BAY AREA
AIR QUALITY
MANAGEMENT
DISTRICT

BOARD OF DIRECTORS
SPECIAL MEETING

May 31, 2017

A special meeting of the Bay Area Air Quality Management District Board of Directors will be held at 9:45 a.m. in the 1st Floor Board Room at the Air District Headquarters, 375 Beale Street, San Francisco, California 94105.

Questions About an Agenda Item

The name, telephone number and e-mail of the appropriate staff Person to contact for additional information or to resolve concerns is listed for each agenda item.

Meeting Procedures

The public meeting of the Air District Board of Directors begins at 9:45 a.m. The Board of Directors generally will consider items in the order listed on the agenda. However, any item may be considered in any order.

After action on any agenda item not requiring a public hearing, the Board may reconsider or amend the item at any time during the meeting.

Public Comment Procedures

Persons wishing to make public comment must fill out a Public Comment Card indicating their name and the number of the agenda item on which they wish to speak, or that they intend to address the Board on matters not on the Agenda for the meeting.

Public Comment on Non-Agenda Matters, Pursuant to Government Code Section 54954.3 Persons submitting Public Comment Cards indicating they wish to speak on matters not on the agenda for the meeting will have three minutes each to address the Board on matters not on the agenda. All Public Comment Cards must be submitted in person to the Clerk of the Boards at the location of the meeting and prior to commencement of the meeting. Speakers typically are allowed three minutes each to speak, however, the Chairperson or other Board Member presiding at the meeting may limit the public comment for all speakers to fewer than three minutes per speaker, or make other rules to ensure that all speakers have an equal opportunity to be heard.

Members of the Board may engage only in very brief dialogue regarding non-agenda matters, and may refer issues raised to District staff for handling. In addition, the Chairperson may refer issues raised to appropriate Board Committees to be placed on a future agenda for discussion.

Public Comment on Agenda Items The public may comment on each item on the agenda as the item is taken up. Public Comment Cards for items on the agenda must be submitted in person to the Clerk of the Boards at the location of the meeting and prior to the Board taking up the particular item. Where an item was moved from the Consent Calendar to an Action item, no speaker who has already spoken on that item will be entitled to speak to that item again.

Speakers typically are allowed three minutes each to speak, however, the Chairperson or other Board Member presiding at the meeting may limit the public comment for all speakers to fewer than three minutes per speaker, or make other rules to ensure that all speakers have an equal opportunity to be heard. The Chairperson or other Board Member presiding at the meeting may, with the consent of persons representing both sides of an issue, allocate a block of time (not to exceed six minutes) to each side to present their issue.

BOARD OF DIRECTORS SPECIAL MEETING AGENDA

WEDNESDAY
MAY 31, 2017
9:45 A.M.

Board Room
1ST Floor

CALL TO ORDER **Chairperson, Liz Kniss**

1. **Opening Comments**
   Roll Call
   Pledge of Allegiance

   The Chair shall call the meeting to order and make opening comments. The Clerk of the Boards shall take roll of the Board members. The Chair shall lead the Pledge of Allegiance.

CONSENT CALENDAR (ITEMS 2 – 3) **Staff/Phone (415) 749-**

2. Minutes of the Board of Directors Regular Meeting of May 17, 2017
   Clerk of the Boards/5073

   The Board of Directors will consider approving the draft minutes of the Regular Board of Directors Meeting of May 17, 2017.

3. Board Communications Received from May 17, 2017 through May 30, 2017
   J. Broadbent/5052
   jbroadbent@baaqmd.gov

   A copy of communications directed to the Board of Directors received by the Air District from May 17, 2017 through May 30, 2017, if any, will be at each Board Member's place.

PUBLIC HEARING

4. Public Hearing to consider staff's evaluation of Regulation 12, Rule 16: Petroleum Refining Facility-Wide Emissions Limits (Rule 12-16) and the associated Environmental Impact Report
   J. Broadbent/5052
   jbroadbent@baaqmd.gov

   The Board of Directors will receive testimony and consider the staff's evaluation of New Regulation 12, Rule 16. The Board may elect to adopt the rule and certify the associated EIR pursuant to the California Environmental Quality Act (CEQA).

PUBLIC COMMENT ON NON-AGENDA MATTERS

5. **Public Comment on Non-Agenda Items, Pursuant to Government Code Section 54954.3**

   Speakers will be allowed one minute each to address the Board on non-agenda matters.

BOARD MEMBERS' COMMENTS

6. *Any member of the Board, or its staff, on his or her own initiative or in response to questions posed by the public, may: ask a question for clarification, make a brief announcement or report on his or her own activities, provide a reference to staff regarding factual information, request staff to report back at a subsequent meeting concerning any matter or take action to direct staff to place a matter of business on a future agenda. (Gov't Code § 54954.2)*

OTHER BUSINESS

7. Report of the Executive Officer/APCO

8. Chairperson's Report

9. Time and Place of Next Meeting:

   Wednesday, June 21, 2017, at 375 Beale Street, San Francisco, CA 94105 at 9:45 a.m.

10. Adjournment

    The Board meeting shall be adjourned by the Board Chair.

CONTACT:

MANAGER, EXECUTIVE OPERATIONS	**(415) 749-5016**
375 BEALE STREET, SAN FRANCISCO, CA 94105	**FAX: (415) 928-8560**
mmartinez@baaqmd.gov	**BAAQMD homepage:**
	www.baaqmd.gov

- To submit written comments on an agenda item in advance of the meeting. Please note that all correspondence must be addressed to the "Members of the Board of Directors" and received at least 24 hours prior, excluding weekends and holidays, in order to be presented at that Board meeting. Any correspondence received after that time will be presented to the Board at the following meeting.

- To request, in advance of the meeting, to be placed on the list to testify on an agenda item.

- Any writing relating to an open session item on this Agenda that is distributed to all, or a majority of all, members of the body to which this Agenda relates shall be made available at the District's offices at 375 Beale Street, Suite 600, San Francisco, CA 94105, at the time such writing is made available to all, or a majority of all, members of that body.

Accessibility and Non-Discrimination Policy

The Bay Area Air Quality Management District (Air District) does not discriminate on the basis of race, national origin, ethnic group identification, ancestry, religion, age, sex, sexual orientation, gender identity, gender expression, color, genetic information, medical condition, or mental or physical disability, or any other attribute or belief protected by law.

It is the Air District's policy to provide fair and equal access to the benefits of a program or activity administered by Air District. The Air District will not tolerate discrimination against any person(s) seeking to participate in, or receive the benefits of, any program or activity offered or conducted by the Air District. Members of the public who believe they or others were unlawfully denied full and equal access to an Air District program or activity may file a discrimination complaint under this policy. This non-discrimination policy also applies to other people or entities affiliated with Air District, including contractors or grantees that the Air District utilizes to provide benefits and services to members of the public.

Auxiliary aids and services including, for example, qualified interpreters and/or listening devices, to individuals who are deaf or hard of hearing, and to other individuals as necessary to ensure effective communication or an equal opportunity to participate fully in the benefits, activities, programs and services will be provided by the Air District in a timely manner and in such a way as to protect the privacy and independence of the individual. Please contact the Non-Discrimination Coordinator identified below at least three days in advance of a meeting so that arrangements can be made accordingly.

If you believe discrimination has occurred with respect to an Air District program or activity, you may contact the Non-Discrimination Coordinator identified below or visit our website at www.baaqmd.gov/accessibility to learn how and where to file a complaint of discrimination.

Questions regarding this Policy should be directed to the Air District's Non-Discrimination Coordinator, Rex Sanders, at (415) 749-4951 or by email at rsanders@baaqmd.gov.

BAY AREA AIR QUALITY MANAGEMENT DISTRICT
375 BEALE STREET, SAN FRANCISCO, CALIFORNIA 94105
FOR QUESTIONS PLEASE CALL (415) 749-5016 or (415) 749-4941

EXECUTIVE OFFICE:
MONTHLY CALENDAR OF AIR DISTRICT MEETINGS

JUNE 2017

TYPE OF MEETING	DAY	DATE	TIME	ROOM
Board of Directors Personnel Committee *(At call of the Chair)*	**Friday**	**2**	**9:30 a.m.**	**1st Floor Board Room**
Board of Directors Regular Meeting *(Meets on the 1st & 3rd Wednesday of each Month)* **- CANCELLED**	**Wednesday**	**7**	**9:45 a.m.**	**1st Floor Board Room**
Board of Directors Executive Committee *(Meets on the 3rd Monday of each Month)*	**Monday**	**19**	**9:30 a.m.**	**1st Floor Board Room**
Board of Directors Stationary Source Committee *(Meets on the 3rd Monday of each Month)*	**Monday**	**19**	**10:30 a.m.**	**1st Floor Board Room**
Board of Directors Regular Meeting *(Meets on the 1st & 3rd Wednesday of each Month)*	**Wednesday**	**21**	**9:45 a.m.**	**1st Floor Board Room**
Board of Directors Mobile Source Committee *(Meets on the 4th Thursday of each Month)*	**Thursday**	**22**	**9:30 a.m.**	**1st Floor Board Room**
Board of Directors Budget & Finance Committee *(Meets on the 4th Wednesday of each Month)*	**Wednesday**	**28**	**9:30 a.m.**	**1st Floor, Yerba Buena Room #109**

JULY 2017

TYPE OF MEETING	DAY	DATE	TIME	ROOM
Board of Directors Regular Meeting *(Meets on the 1st & 3rd Wednesday of each Month)*	**Wednesday**	**5**	**9:45 a.m.**	**1st Floor Board Room**
Board of Directors Executive Committee *(Meets on the 3rd Monday of each Month)*	**Monday**	**17**	**9:30 a.m.**	**1st Floor Board Room**
Board of Directors Stationary Source Committee *(Meets on the 3rd Monday of each Month)*	**Monday**	**17**	**10:30 a.m.**	**1st Floor Board Room**
Board of Directors Regular Meeting *(Meets on the 1st & 3rd Wednesday of each Month)*	**Wednesday**	**19**	**9:45 a.m.**	**1st Floor Board Room**
Board of Directors Climate Committee *(Meets on the 3rd Thursday of every other Month)*	**Thursday**	**20**	**9:30 a.m.**	**1st Floor Board Room**
Advisory Council Meeting *(Meets on Monday Quarterly)*	**Monday**	**24**	**9:45 a.m.**	**1st Floor Board Room**
Board of Directors Budget & Finance Committee *(Meets on the 4th Wednesday of each Month)*	**Wednesday**	**26**	**9:30 a.m.**	**1st Floor, Yerba Buena Room #109**
Board of Directors Mobile Source Committee *(Meets on the 4th Thursday of each Month)*	**Thursday**	**27**	**9:30 a.m.**	**1st Floor Board Room**

BAY AREA AIR QUALITY MANAGEMENT DISTRICT
Memorandum

To: Chairperson Liz Kniss and Members
of the Board of Directors

From: Jack P. Broadbent
Executive Officer/APCO

Date: May 17, 2017

Re: Minutes of the Board of Directors Regular Meeting of May 17, 2017

RECOMMENDED ACTION

Approve the attached draft minutes of the Board of Directors Regular Meeting of May 17, 2017.

DISCUSSION

Attached for your review and approval are the draft minutes of the Board of Directors Regular Meeting of May 17, 2017.

Respectfully submitted,

Jack P. Broadbent
Executive Officer/APCO

Prepared by: Marcy Hiratzka
Reviewed by: Maricela Martinez

Attachment 2A: Draft Minutes of the Board of Directors Regular Meeting of May 17 2017.

Bay Area Air Quality Management District
375 Beale Street, Suite 600
San Francisco, CA 94105
(415) 749-5073

Board of Directors Regular Meeting
Wednesday, May 17, 2017

DRAFT MINUTES

Note: Audio recordings of the meeting are available on the website of the Bay Area Air Quality Management District at http://www.baaqmd.gov/about-the-air-district/board-of-directors/resolutionsagendasminutes

CALL TO ORDER:

1. **Opening Comments:** Chairperson, Liz Kniss, called the meeting to order at 11:11 a.m.

Roll Call:

Present: Chairperson Liz Kniss; Vice Chairperson Dave Hudson; Secretary Katie Rice; and Directors Margaret Abe-Koga, Teresa Barrett, Pauline Russo Cutter, John Gioia, Scott Haggerty, Rebecca Kaplan, Doug Kim, Hillary Ronen, Mark Ross, Pete Sanchez, Jeff Sheehy, Rod Sinks, Jim Spering, Brad Wagenknecht, and Shirlee Zane.

Absent: Directors David J. Canepa, Cindy Chavez, Carole Groom, Nate Miley, Karen Mitchoff, and Tyrone Jue.

PUBLIC COMMENT ON NON-AGENDA MATTERS

2. **Public Comment on Non-Agenda Items, Pursuant to Government Code Section 54954.3**

Public comments were made by Tony Fisher, Coalition for Clean Air; Bob Brown, Western States Petroleum Association; and Mike Miller, United Steel Workers Local 326.

CONSENT CALENDAR (ITEMS 3-7)

3. Minutes of the Regular Board of Directors Meeting of April 19, 2017
4. Board Communications Received from April 19, 2017 through May 16, 2017
5. Air District Personnel on Out-of-State Business Travel
6. Notices of Violation Issued and Settlements in Excess of $10,000 in the Month of April 2017
7. Quarterly Report of the Executive Office and Division Activities for the Months of January 2017 – March 2017

Public Comments:

No requests received.

Board Comments:

None.

Board Action:

Director Kaplan made a motion, seconded by Director Zane, to **approve** the Consent Calendar Items 3 through 7, inclusive; and the motion **carried** by the following vote of the Board:

AYES:	Abe-Koga, Barrett, Cutter, Gioia, Haggerty, Hudson, Kaplan, Kim, Kniss, Rice, Ronen, Ross, Sanchez, Sheehy, Sinks, Spering, Wagenknecht, and Zane.
NOES:	None.
ABSTAIN:	None.
ABSENT:	Canepa, Chavez, Groom, Jue, Miley, and Mitchoff.

COMMITTEE REPORTS

8. Report of the Budget and Finance Committee Meeting of April 26, 2017

Budget and Finance Committee Vice Chair, Katie Rice, read the following Committee report:

The Committee met on Wednesday, April 26, 2017 and approved the minutes of March 22, 2017.

The Committee reviewed and discussed the staff presentation Continued Discussion of Fiscal Year Ending 2018 Proposed Air District Budget and Consideration to Recommend Adoption. The Committee recommends the Board:

1. *Adopt the Fiscal Year Ending 2018 Proposed Budget.*

The Committee then reviewed and discussed the presentation Pension Rate Stabilization Program and Other Post-Employment Benefits Pre-Funding Using 115 Trust Administered by Public Agency Retirement Services (PARS.)

Finally, the Committee reviewed and discussed the staff presentation Third Quarter Financial Report for Fiscal Year Ending 2017.

The next meeting of the Budget and Finance Committee is at the call of the Chair. I move that the Board approve the Budget and Finance Committee's recommendation. This concludes the Chair Report of the Budget and Finance Committee.

Public Comments:

No requests received.

Board Comments:

None.

Board Action:

Secretary Rice made a motion, seconded by Vice Chair Hudson, to **approve** the recommendations of the Budget and Finance Committee; and the motion **carried** by the following vote of the Board:

AYES:	Abe-Koga, Barrett, Cutter, Gioia, Haggerty, Hudson, Kaplan, Kim, Kniss, Rice, Ronen, Ross, Sanchez, Sheehy, Sinks, Spering, Wagenknecht, and Zane.
NOES:	None.
ABSTAIN:	None.
ABSENT:	Canepa, Chavez, Groom, Jue, Miley, and Mitchoff.

9. Report of the Legislative Committee Meeting of May 11, 2017

Legislative Committee Chair, Brad Wagenknecht, read the following Committee report:

The Legislative Committee met on Thursday, May 11, 2017, and approved the minutes of December 12, 2016, and March 30, 2017.

The Committee discussed the following bills and recommends that the Board of Directors take the following positions:

- *AB 378 (C. Garcia): Oppose unless amended;*
- *AB 476 (Gipson): Oppose; and*
- *SB 775 (Wieckowski): Support in concept.*

Three additional bills were discussed at the Committee meeting, and the Committee recommends that the Board of Directors take the following positions:

- *AB 458 (Frazier): Oppose unless amended;*
- *AB 1218 (Obernolte): Support; and*
- *SB 100 (De Leòn): Support in concept.*

The Committee also discussed six principles to guide staff, as the Legislature negotiates changes to AB 378 and SB 775 over the next month, and recommends Board of Directors' approval. Copies of the additional bills and the principles are at your places.

The next meeting of the Committee is at the Call of the Chair. I move that the Board approve the Committee's recommendations. This concludes the Chair's report of the Legislative Committee.

Public Comments:

No requests received.

Board Comments:

The Board and staff discussed the Board's request for titles of new bills under consideration to be included in Committee and Chair reports for Board meetings; why the District supports returning Cap and Trade auction revenues to the public; and whether the District's interests are consistent with those of the California Community Choice Association, as community choice aggregation options are now available within all nine Bay Area Counties.

Board Action:

Director Wagenknecht made a motion, seconded by Vice Chair Hudson, to **approve** the recommendations of the Legislative Committee; and the motion **carried** by the following vote of the Board:

AYES:	Abe-Koga, Barrett, Cutter, Gioia, Haggerty, Hudson, Kaplan, Kim, Kniss, Rice, Ronen, Ross, Sanchez, Sheehy, Sinks, Spering, Wagenknecht, and Zane.
NOES:	None.
ABSTAIN:	None.
ABSENT:	Canepa, Chavez, Groom, Jue, Miley, and Mitchoff.

PRESENTATION

10. Briefing on the Valero Benicia Refinery Incident of May 5, 2017

Jack Broadbent, Executive Officer/Air Pollution Control Officer, introduced Wayne Kino, Director of Compliance and Enforcement, who gave the staff presentation *Briefing on the Valero Benicia Refinery Incident of May 5, 2017,* including: refinery location; incident overview; response; air quality impacts; agencies' monitoring efforts; and investigation.

Public Comments:

Public comments were given by Greg Karras, Communities for a Better Environment.

Board Comments:

The Board and staff discussed why the Valero refinery lacks backup power generation capabilities; whether air monitoring was extended to Community Air Risk Evaluation (CARE) areas adjacent to the refinery following the incident, and the consideration of monitoring resources for future incidents; the status of the District's installation of fence line monitoring systems per Regulation 12, Rule 15 (Petroleum Refining Emissions Tracking), and how such systems might have helped during this incident; the feasibility of a District policy that would result in the ceasing of refinery operations based upon a maximum number of Notices of Violations that are issued to a refinery, pertaining to a significant incident; the monitoring of health effects in vulnerable communities and schools that were affected by this incident; root cause analysis, and which agencies have the authority to remediate the situation; and the frequency of flaring incidents at refineries.

Board Action:

None; receive and file.

PUBLIC COMMENT ON NON-AGENDA MATTERS

11. Public Comment on Non-Agenda Items, Pursuant to Government Code Section 54954.3

No requests received.

BOARD MEMBERS' COMMENTS

12. Board Member's Comments

Director Zane announced that the Sonoma County Water Agency was awarded the Spare the Air Leadership Award, for developing a diverse renewable energy portfolio, and implementing a range of efficiency measures to deliver water without a carbon footprint.

Director Kaplan announced that the dispute over the proposed coal export terminal in West Oakland is continuing, and welcomed any support from agencies who oppose this proposal, as regional impacts are anticipated.

Chair Kniss acknowledged the District's 2016 Annual Report.

OTHER BUSINESS

13. Report of the Executive Officer/Air Pollution Control Officer

Mr. Broadbent's presentation on ozone seasons has been posted on the District website.

14. Chairperson's Report

None.

15. Time and Place of Next Meeting

Wednesday, May 31, 2017, at 375 Beale Street, 1st Floor Board Room, San Francisco, CA 94105 at 9:45 a.m.

16. Adjournment

The meeting adjourned at 12:13 p.m.

Marcy Hiratzka
Clerk of the Boards

BAY AREA AIR QUALITY MANAGEMENT DISTRICT
Memorandum

To: Chairperson Liz Kniss and Members
of the Board of Directors

From: Jack P. Broadbent
Executive Officer/APCO

Date: May 17, 2017

Re: Board Communications Received from May 17, 2017 through May 30, 2017

RECOMMENDED ACTION

None; receive and file.

DISCUSSION

Copies of communications directed to the Board of Directors received by the Air District from May 17, 2017, through May 30, 2017, if any, will be at each Board Member's place at the April 19, 2017, Board meeting.

Respectfully submitted,

Jack P. Broadbent
Executive Officer/APCO

Prepared by: Aloha Galimba
Reviewed by: Maricela Martinez

BAY AREA AIR QUALITY MANAGEMENT DISTRICT
Memorandum

To: Chairperson Liz Kniss and Members of the Board of Directors

From: Jack P. Broadbent
Executive Officer/APCO

Date: May 24, 2017

Re: Public Hearing to consider staff's evaluation of Regulation 12, Rule 16: Petroleum Refining Facility-Wide Emissions Limits (Rule 12-16) and the associated Environmental Impact Report

RECOMMENDED ACTION

Consider new Regulation 12: Miscellaneous Standards of Performance, Rule 16: Petroleum Refining Facility-Wide Emissions Limits for adoption and certify appropriate portions of the EIR dealing with Rule 12-16.

BACKGROUND

On December 16, 2015, the Board unanimously approved the first phase of the Refinery Emission Reduction Strategy which will reduce refinery emissions by 14%. These rules included: Regulation 6-5: Fluid Catalytic Cracking Units, Regulation 8, Rule 18: Equipment Leaks and Regulation 11, Rule 10: Cooling Towers. On April 20, 2016, the Board adopted Regulation 9, Rule 14: Petroleum Coke Calcining Operations which will further reduce refinery industry emissions between 1 and 3%. The Board also adopted Regulation 12, Rule 15: Petroleum Refining Emissions Tracking which will require improved and expanded emissions inventories from Bay Area refineries and support facilities, expanded fence-line monitoring at the refineries and the review of the composition and property data for crude oil and feedstocks processed at the refinery.

At the July 20, 2016 meeting, the Board of Directors further directed staff to develop regulatory language that represents a proposal by Communities for a Better Environment and associated organizations (CBE) to limit emissions from petroleum refining facilities and three support facilities. The CBE proposal specified numeric limits on Greenhouse Gas (GHG), and three criteria pollutants: particulate matter (PM), oxides of nitrogen (NOx) and sulfur dioxide (SO_2). The limits in the CBE proposal are based on historic emission levels. Staff continued to raise concerns about the proposal regarding the legality of certain aspects of the proposal, particularly those associated with specifying criteria pollutant caps on refineries. Staff also investigated alternative methods to address concerns about changing refinery operations increasing combustion emissions and began developing a draft new rule, Regulation 13, Rule 1, concurrently to Rule 12-16 development, Rule 13-1 is intended to be the first step in addressing combustion related emissions, including GHGs, throughout the Bay Area.

At the same Board meeting in July, the Board of Directors directed staff to prepare an Environmental Impact Report (EIR) to analyze the environmental impacts of two rules: the proposal by CBE (draft Regulation 12, Rule 16 or "Rule 12-16") and, a proposal by staff to significantly reduce toxic risk from refineries and hundreds of other sources throughout the Bay Area (draft Regulation 11, Rule 18 or "Rule 11-18") that would address localized impacts of toxic air contaminants to nearby communities.

DISCUSSION

As directed by the Board of Directors, staff developed draft Rule 12-16 to ensure that it represented the concepts developed by CBE to place specific, numeric caps for GHG, PM, NOx and SO_2 on each of the five Bay Area refineries, and on three support facilities that supply products directly to the refineries.

In order to consider and address input from government agencies, hospitals, and small businesses, Rule 11-18 will be brought to the Board in the third quarter of 2017. The Rule 11-18 portion of the EIR will not be considered for certification by the Board in this hearing, because it may need to be revised based on these stakeholder discussions. However, the portion the EIR that addresses Rule 12-16 will be available for the Board to certify, if they so desire, at this hearing where they are considering Rule 12-16.

In addition to working with stakeholders during the rule development process, staff conducted public outreach at four Open House Workshops conducted at Cupertino on March 27th, Benicia on March 28th, Hayward on March 29th and Richmond on March 30th. Public workshop notices, the draft 12-16 rule language, the staff report, the socioeconomic report and the EIR are available on the Air District website at http://www.baaqmd.gov/rulehearings.

BUDGET CONSIDERATIONS/FINANCIAL IMPACTS

Draft Rule 12-16 will require that emissions be appropriately tracked, and compliance determined annually. Increased workloads are expected to result in the need for additional staff in the Engineering Division to conduct these activities. Cost recovery percentages are expected to decrease until fees to refineries can be adjusted to incorporate increased staff costs.

Respectfully submitted,

Jack P. Broadbent
Executive Officer/APCO

Prepared by: Eric Stevenson
Reviewed by: Jean Roggenkamp

Attachment 4A: Final Regulatory Language for Rule 12-16
Attachment 4B: Final Staff Report for Rule 12-16, with Appendices
Attachment 4C: Comments and Responses on Staff Report
Attachment 4D: Final Socioeconomic Report for Rule 12-16
Attachment 4E: Environmental Impact Report for Rule 12-16
Attachment 4F: Comments and Responses on Environmental Impact Report
Attachment 4G: Advisory Council Efficacy of GHG Caps on Bay Area Refineries

AGENDA 4A - ATTACHMENT

REGULATION 12
MISCELLANEOUS STANDARDS OF PERFORMANCE
RULE 16
PETROLEUM REFINING FACILITY-WIDE EMISSIONS LIMITS

INDEX

REGULATION 12
MISCELLANEOUS STANDARDS OF PERFORMANCE
RULE 16
PETROLEUM REFINING EMISSIONS LIMITS

(Adopted May XX, 2017)

12-16-100 GENERAL

12-16-101 **Description:** The purpose of this rule is to limit GHG, PM_{10}, $PM_{2.5}$, NO_x and SO_2 emissions from petroleum refineries and associated support facilities.

12-16-102 **Exemption, Small Refineries**: This rule shall not apply to any refinery that is limited by an Air District Permit to Operate to a total crude oil throughput or total crude oil processing capacity of 5,000 barrels per day or less.

12-16-200 DEFINITIONS

12-16-201 **Accidental Air Release:** An unanticipated emission of a criteria pollutant, toxic air contaminant, and/or greenhouse gas into the atmosphere required to be reported in a Risk Management Plan (RMP) under 40 CFR §68.168.

12-16-202 **Ambient Air:** The portion of the atmosphere external to buildings to which the general public has access.

12-16-203 **Annual Emissions Inventory:** An emissions inventory at a Petroleum Refinery covering a calendar year period.

12-16-204 **Criteria Pollutant:** An air pollutant for which an ambient air quality standard has been established, or that is an atmospheric precursor to such an air pollutant. For the purposes of this rule, criteria pollutants are carbon monoxide (CO), oxides of nitrogen (NOx), particulate matter with an aerodynamic diameter of 10 micrometers or less (PM_{10}), particulate matter with an aerodynamic diameter of 2.5 micrometers or less ($PM_{2.5}$), precursor organic compounds (POC), and sulfur dioxide (SO_2).

12-16-205 **Crude Oil:** Petroleum, as it occurs after being extracted from geologic formations by an oil well, and after extraneous substances may have been removed, and which may be subsequently processed at a Petroleum Refinery.

12-16-206 **Emissions Inventory:** As defined in Rule 12-15-206.

12-16-207 **Greenhouse Gases (GHGs)**: The air pollutant that is defined in 40 CFR § 86.1818-12(a), which is a single air pollutant made up of a combination of the following six constituents: carbon dioxide, nitrous oxide, methane, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride. For the purposes of this rule, GHG emissions should be calculated in manner consistent with California Air Resources Board requirements as contained in §95113 of the Mandatory Greenhouse Gas Emissions Reporting Rule.

12-16-208 **Permit to Operate:** A written authorization obtained per BAAQMD Regulation 2, Rule 1, Section 301.

12-16-209 **Petroleum Refinery:** An establishment that is located on one or more contiguous or adjacent properties that processes crude oil to produce more usable products such as gasoline, diesel fuel, aviation fuel, lubricating oils, asphalt or petrochemical feedstocks. Petroleum Refinery processes include separation processes (e.g., atmospheric or vacuum distillation, and light ends recovery), petroleum conversion processes (e.g., cracking, reforming, alkylation, polymerization, isomerization, coking, and visbreaking), petroleum treating processes (e.g., hydrodesulfurization, hydrotreating, chemical sweetening, acid gas removal, and deasphalting), feedstock and product handling (e.g., storage, crude oil blending, non-crude oil feedstock blending, product blending, loading, and unloading), and auxiliary facilities (e.g., boilers, waste water treatment, hydrogen production, sulfur recovery plant, cooling towers, blowdown systems, compressor engines, and power plants).

12-16-210 **Source:** As defined in BAAQMD Regulation 2, Rule 1, Section 221.

12-16-300 STANDARDS

12-16-301 Greenhouse Gas Emissions Limits: Effective January 1, 2018, the owner/operator of any petroleum refinery or listed related facility shall not emit greenhouse gas emissions that exceed the emissions limits shown in Table 12-16-301.

Table 12-16-301: GHG Emission Limits

Facility	2011–2015 Baseline[1] (metric tons/year)	Seven Percent Operating Variation (metric tons/year)	Emission Limit (metric tons/year)
Chevron Refinery A-0010	4.46 M	312 K	4.77 M
Shell Refinery A-0011	4.26 M	298 K	4.56 M
Phillips 66 Refinery A-0016	1.50 M	105 K	1.61 M
Tesoro Refinery B-2758/2759	2.44 M	171 K	2.61 M
Valero Refinery, B-2626 & Asphalt Plant, B-3193	2.94 M	206 K	3.15 M
Martinez Cogen LP A-1820	421 K	29.5 K	450 K
Air Liquide H2 Plant B7419	885 K	61.9 K	947 K
Air Products H2 Plant B-0295	271 K	19.0 K	290 K

M = Millions, K = Thousands

[1] Maximum annual emissions from 2011 – 2015 baseline years, California Air Resources Board Emissions Inventory: Mandatory GHG Reporting - Reported Emissions, ARB Calculated Covered Emissions (metric tons CO2e) https://www.arb.ca.gov/cc/reporting/ghg-rep/reported-data/ghg-reports.htm

12-16-302 Particulate Matter (PM_{10}) Emissions Limits: Effective January 1, 2018, the owner/operator of any petroleum refinery or listed related facility shall not emit particulate matter (PM_{10}) emissions that exceed the emissions limits shown in Table 12-16-302.

Table 12-16-302: Particulate Matter (PM_{10}) Emission Limits

Facility	2010–2014 Baseline[2] (tons/year)	Seven Percent Operating Variation (tons/year)	Emission Limit (tons/year)
Chevron Refinery A-0010	491	34.4	525
Shell Refinery A-0011	550	38.5	589
Phillips 66 Refinery A-0016	77.7	5.44	83.1
Tesoro Refinery B-2758/2759	90.7	6.35	97.0
Valero Refinery, B-2626 & Asphalt Plant, B-3193	125	8.75	134
Martinez Cogen LP A-1820	17.6	1.23	18.8
Air Liquide H2 Plant	16.1	1.13	17.2

Facility	**2010–2014 Baseline**[2] (tons/year)	**Seven Percent Operating Variation** (tons/year)	**Emission Limit** (tons/year)
B7419			
Air Products H2 Plant B-0295	9.71	0.68	10.4

[2] Maximum annual emissions from 2010 – 2014 baseline years, Annual Emissions Inventories (reported to ARB via CEIDARS), adjusted to exclude Flare and Cooling Water Tower emissions.

12-16-303 Particulate Matter ($PM_{2.5}$) Emissions Limits: Effective January 1, 2018, the owner/operator of any petroleum refinery or listed related facility shall not emit particulate matter ($PM_{2.5}$) emissions that exceed the emissions limits shown in Table 12-16-303.

Table 12-16-303: Particulate Matter ($PM_{2.5}$) Emission Limits

Facility	**2010–2014 Baseline**[3] (tons/year)	**Seven Percent Operating Variation** (tons/year)	**Emission Limit** (tons/year)
Chevron Refinery A-0010	469	32.8	502
Shell Refinery A-0011	463	32.4	495
Phillips 66 Refinery A-0016	70.1	4.91	75.0
Tesoro Refinery B-2758/2759	72.6	5.08	77.7
Valero Refinery, B-2626 & Asphalt Plant, B-3193	124	8.72	133
Martinez Cogen LP A-1820	17.6	1.23	18.8
Air Liquide H2 Plant B7419	15.0	1.06	16.1
Air Products H2 Plant B-0295	9.06	0.63	9.69

[3] Maximum annual emissions from 2010 – 2014 baseline years, Annual Emissions Inventories (reported to ARB via CEIDARS), adjusted to exclude Flare and Cooling Water Tower emissions.

12-16-304 Nitrogen Oxide (NO_x) Emissions Limits: Effective January 1, 2018, the owner/operator of any petroleum refinery or listed related facility shall not emit nitrogen oxide (NOx) emissions that exceed the emissions limits shown in Table 12-16-304.

Table 12-16-304: Nitrogen Oxide (NO_x) Emission Limits

Facility	**2010–2014 Baseline**[4] (tons/year)	**Seven Percent Operating Variation** (tons/year)	**Emission Limit** (tons/year)
Chevron Refinery A-0010	907	63.5	970
Shell Refinery A-0011	998	69.9	1.07 K
Phillips 66 Refinery A-0016	270	18.9	289
Tesoro Refinery	949	66.4	1.02 K

Facility	**2010–2014 Baseline[4]** (tons/year)	**Seven Percent Operating Variation** (tons/year)	**Emission Limit** (tons/year)
B-2758/2759			
Valero Refinery, B-2626 & Asphalt Plant, B-3193	1.20 K	84.0	1.28 K
Martinez Cogen LP A-1820	111	7.77	119
Air Liquide H2 Plant B7419	12.7	0.90	13.6
Air Products H2 Plant B-0295	8.25	0.58	8.83

K = Thousands

[4] Maximum annual emissions from 2010 – 2014 baseline years, Annual Emissions Inventories (reported to ARB via CEIDARS), adjusted to exclude Flare and Cooling Water Tower emissions.

12-16-305 Sulfur Dioxide (SO_2) Emissions Limits: Effective January 1, 2018, the owner/operator of any petroleum refinery or listed related facility shall not emit sulfur dioxide (SO_2) emissions that exceed the emissions limits shown in Table 12-16-305.

Table 12-16-305: Sulfur Dioxide (SO_2) Emission Limits

Facility	**2010–2014 Baseline[5]** (tons/year)	**Seven Percent Operating Variation** (tons/year)	**Emission Limit** (tons/year)
Chevron Refinery A-0010	368	25.8	394
Shell Refinery A-0011	1.36 K	95.2	1.46 K
Phillips 66 Refinery A-0016	365	25.6	391
Tesoro Refinery B-2758/2759	602	42.1	644
Valero Refinery, B-2626 & Asphalt Plant, B-3193	65.1	4.56	69.7
Martinez Cogen LP A-1820	2.15	0.15	2.30
Air Liquide H2 Plant B7419	2.35	0.16	2.51
Air Products H2 Plant B-0295	2.70	0.19	2.89

K = Thousands

[5] Maximum annual emissions from 2010 – 2014 baseline years, Annual Emissions Inventories (reported to ARB via CEIDARS), adjusted to exclude Flare and Cooling Water Tower emissions.

12-16-400 ADMINISTRATIVE REQUIREMENTS

12-15-500 MONITORING AND RECORDS

12-16-501 **Determination of Compliance**: Compliance is determined by comparing the Annual Emissions Inventory submitted by each petroleum refinery and support facility, reviewed and approved by the APCO, to the total emissions limits established in Section 12-16-301 - 305.

501.1 **Annual Emissions Inventory:** The Annual Emissions Inventory shall be submitted to the Air District by June 30 of each year as required by Regulation 12, Rule 15, Section 401.

501.2 **Adjusted Annual Emissions Inventory:** The District will adjust the Annual Emissions Inventory to exclude Flare and Cooling Water Tower emissions. The adjusted Annual Emissions Inventory establishes the actual emissions for each calendar year, and will be compared to each facility's emissions limits.

501.3 **Emissions Limits:** Emissions limits are established in Sections 12-16-301 – 305.

501.4 **Compliance Determination:** Beginning in 2019 the District will compare the previous year's annual emission inventory for each pollutant from each facility with the emission limit for each pollutant from each facility. If the emission limit is greater than the annual emission inventory for each of the five limited pollutants (GHG, PM_{10}, $PM_{2.5}$, NO_x and SO_2) the facility is in compliance.

501.5 **Emission Limit Exceedance:** If the annual emission inventory is greater than the emission limit for any of the five limited pollutants (GHG, PM_{10}, $PM_{2.5}$, NO_x and SO_2) the facility is not in compliance. Each exceedance of an emission limit shall be considered a violation for each day of the calendar year for the relevant emission inventory.

12-16-502 **Records**: The Annual Emissions Inventory Report shall be submitted to the District by June 30 of each year, as required by Regulation 12, Rule 15, Section 401.

12-15-600 MANUAL OF PROCEDURES

12-16-601 **Determination of Compliance Procedure**: Manual of Procedures (MOP) Volume 1, Enforcement Procedures; Part XX, Assessment of Refinery and Support Facility Emissions Compliance establishes the procedure for excluding Flare and Cooling Water Tower emissions from the Annual Emissions Inventories, and comparing the Annual Emissions Inventories to the Emission Limits for each Petroleum Refinery and Support Facility.

AGENDA 4B- ATTACHMENT

BAY AREA
AIR QUALITY
MANAGEMENT
DISTRICT

Regulation 12, Rule 16:
Petroleum Refining Facility-Wide Emissions Limits

FINAL STAFF REPORT

May 2017

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Table of Contents

I. EXECUTIVE SUMMARY

Petroleum refineries are significant sources of harmful pollutants on both the global (greenhouse gases) and regional/local scale (toxic air contaminants and criteria pollutants). Many Bay Area residents have expressed concern about the impact of this pollution on the environment and public health. Though refinery emissions have declined over time, it is possible that, as refinery operations change in the future, emissions of these pollutants could increase.

Communities for a Better Environment and several associated organizations (CBE) have developed a concept and the Board of Directors have directed Air District staff to develop regulatory language reflecting that concept into new Regulation 12, Rule 16: Petroleum Refining Facility-Wide Emissions Limits (Rule 12-16 or “Refining Caps Rule”). This rule would set numeric limits on specific refinery emissions. Rule 12-16 would apply only to the Bay Area’s five petroleum refineries and three facilities associated with the refineries.

Air District staff has analyzed Rule 12-16 and found the limits in the rule to have been set at a level consistent with the current production capacity of the refineries as a group. Compliance would be demonstrated through the annual emissions inventory process. The economic impacts of the rule are uncertain and depend on whether overall California refinery capacity decreases due to closure or unexpected incidents or whether the consumption of transportation fuels declines, as predicted by the California Air Resources Board (CARB), or increases as it has been doing since 2012. Air District staff believes CBE’s proposed concept for Rule 12-16 would likely be found to be beyond the Air District’s authority, especially where criteria pollutant compounds are capped, and/or potentially arbitrary and capricious by a Court. Staff’s analysis also indicates that the refining caps concept will not improve air quality in refinery communities.

The staff of the Air District believes that the suite of rules under development or recently adopted will better address community concerns about the air quality impacts from refinery emissions. Rules already adopted by the Air District are projected to reduce criteria pollutant emissions from the refining sector by 17 percent. Other emission reduction rules currently under development will further reduce those criteria pollutant emissions. Regulation 11, Rule 18 (Rule 11-18), currently under development, will limit health risk from Toxic Air Contaminants (TAC) from refineries and other sources across the Air District, addressing concerns about impacts in areas near affected facilities. Regulation 13, Rule 1 (Rule 13-1), currently under development, will limit the carbon intensity of refining. It is designed to prevent significant increases in combustion emissions, including CO_2, due to changes in refining operations that have the potential to result in burning more fuel to process different crude oil feedstocks, such as heavier and more sulfurous crude oil.

In response to the direction of the Board of Directors, staff has prepared the refining caps concept as a rule package. This final staff report is a summary and explanation of Rule 12-16. The report will be published along with the Environmental Impact Report required under the California Environmental Quality Act.

II. BACKGROUND

Air District staff has developed regulatory language at the direction of its Board of Directors based on a concept proposed by CBE to limit refinery combustion emissions at a level consistent with the refineries' recent operations. Air District staff has developed Rule 12-16 working with CBE to ensure the regulatory language meets the goals of the concept. The draft rule would establish emissions limits for greenhouse gases (GHG's), nitrogen oxides (NO_x), sulfur dioxide (SO_2), and particulate matter 10 microns and smaller (PM_{10}) and particulate matter 2.5 microns and smaller ($PM_{2.5}$).

At the direction of the Board, the staff of the Air District has prepared this staff report to describe the draft Rule 12-16, and to provide an assessment of the rule's consistency with the Air District's statutory authority.

A. Petroleum Refinery

Currently, the five petroleum refineries located in the Bay Area within the jurisdiction of the Air District that would be affected by the rule are:

1. Chevron Products Company, Richmond (BAAQMD Plant #10)
2. Phillips 66 Company—San Francisco Refinery, Rodeo (BAAQMD Plant #21359)
3. Shell Martinez Refinery, Martinez (BAAQMD Plant #11)
4. Tesoro Refining and Marketing Company, Martinez (BAAQMD Plant #14628)
5. Valero Refining Company—California, Benicia (BAAQMD Plant #12626) and associated Asphalt Plant (BAAQMD Plant #13193)

The three affected, refinery-related facilities are:

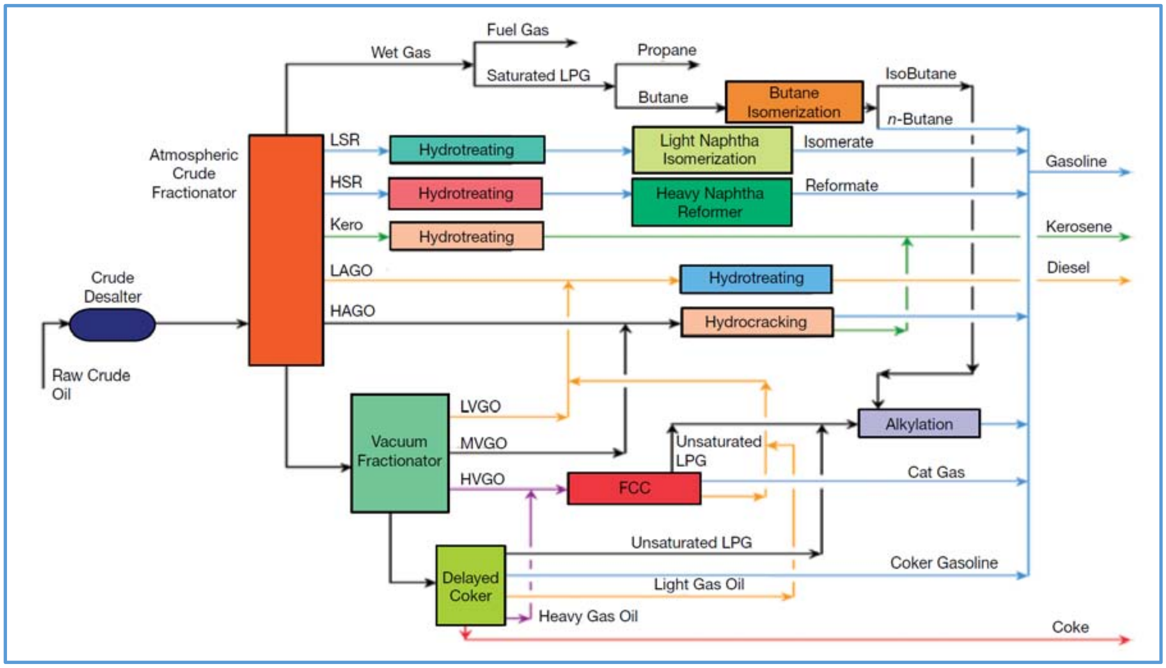
1. Air Products and Chemicals hydrogen plant, Martinez (BAAQMD Plant #10295)
2. Air Liquide hydrogen plant, Rodeo (BAAQMD Plant #17419)
3. Martinez Cogen, L.P. (BAAQMD Plant #1820)

These three support facilities are subject to provisions of the rule because each is closely linked to the operations of a refinery.

1. PETROLEUM REFINERY PROCESS DESCRIPTION

These facilities process crude oil into a variety of products such as gasoline, aviation fuel, diesel and other fuel oils, lubricating oils, and feedstocks for the petrochemical industry. The diagram in Figure 1 illustrates how various process units at petroleum refineries convert raw crude oil (petroleum) into fuels and other products.

Figure 1: Refinery Flow Diagram



Legend: LSR = light straight-run naphtha; HSR = heavy straight-run naphtha; Kero = kerosene; LAGO = light atmospheric gas oil; HAGO = heavy atmospheric gas oil; LVGO = light vacuum gas oil; MVGO = medium vacuum gas oil; HVGO = heavy vacuum gas oil.

The processing of crude oil occurs in various process units or plants; some of the primary process units include:

- Crude Desalter: Crude oil is mixed with water to separate the salt and sediments from the crude.
- Crude Unit: The incoming desalted crude oil is heated and distilled into various fractions for further processing in other units.
- Gas Concentration Unit: Light hydrocarbons from the top of the crude unit are separated and distributed in the refinery fuel gas (RFG) system for use as fuel for heaters and boilers.
- Vacuum Distillation Unit: The residue oil from the bottom of the crude oil distillation unit is further distilled under heavy vacuum.
- Hydrotreater: Naphtha, kerosene, and gas oil are desulfurized from the crude unit by using hydrogen and converting the organically bound sulfur into hydrogen sulfide (a toxic compound).
- Fluidized Catalytic Cracker Unit: Longer chain, higher boiling hydrocarbons such as heavy oils are broken (or “cracked”) into lighter, shorter molecules at high temperatures and moderate pressure in the presence of a catalyst. This process is so named because the catalyst is so fine that it behaves like a fluid.
- Butane Isomerization Unit: Polymers of butane are reformed into isobutane for use in the alkylation process. Alkylates are used in blending gasoline to boost the octane rating. Alkylates are considered one of the highest quality refinery products.

- Light Naphtha Isomerization Unit: Benzene is saturated and short, straight-chain hydrocarbons are isomerized into branched-chain hydrocarbons.
- Heavy Naphtha Reformer and Hydrotreater: Low-octane linear hydrocarbons (paraffins) are converted into aromatics using a catalyst. The process also forms hydrogen - used in the refinery's hydrocracking and hydrotreating units - and benzene, toluene, and xylene (BTX) feedstocks, used in other process units.
- Hydrocracker Unit: Hydrogen is used to upgrade heavier fractions into lighter, more valuable products, such as diesel and jet fuel, in a high-pressure system.
- Alkylation Unit: Butene and propene are reacted with isobutane into alkylate, a high-octane gasoline component.
- Delayed Coker: Very heavy residual oils are converted into end-product petroleum coke as well as naphtha and diesel oil byproducts.
- Claus Sulfur Plant: A two-step (thermal and catalytic) process for recovering sulfur from gaseous hydrogen sulfide (H_2S) derived from refining crude oil. In the thermal step, H_2S laden gas is combusted to form elemental sulfur and sulfur dioxide (SO_2). In the catalytic step, a catalyst is used to boost the sulfur yield. In this step, H_2S reacts with SO_2 to form elemental sulfur.

a. Separation Processes

Crude oil consists of a complex mixture of hydrocarbon compounds with small amounts of impurities such as sulfur, nitrogen, and metals. The first phase in petroleum refining is the separation of crude oil into its major constituents using distillation and "light ends" recovery (i.e., gas processing) that splits crude oil constituents into component parts known as "boiling-point fractions."

b. Conversion Processes

Crude oil components such as residual oils, fuel oils, and other light fractions are converted to high-octane gasoline, jet fuel, and diesel fuel, gasoline by various processes. These processes, such as cracking, coking, and visbreaking (a form of thermal cracking that breaks the viscosity), are used to break large petroleum molecules into smaller ones. Polymerization and alkylation processes are used to combine small petroleum molecules into larger ones. Isomerization and reforming processes are applied to rearrange the structure of petroleum molecules to produce higher-value molecules using the same atoms.

c. Treating Processes

Petroleum treating processes stabilize and upgrade petroleum products by separating them from less desirable products, and by removing other elements. Treating processes, employed primarily for the separation of petroleum products, include processes such as de-asphalting. Elements such as sulfur, nitrogen, and oxygen are removed by hydrodesulfurization, hydrotreating, chemical sweetening, and acid gas removal.

d. Feedstock and Product Handling

Refinery feedstock and product handling operations consist of unloading, storage, blending, and loading activities.

e. Auxiliary Facilities

A wide assortment of processes and equipment not directly involved in the processing of crude oil are used in functions vital to the operation of the refinery. Examples include steam boilers, wastewater treatment facilities, hydrogen plants, cooling towers, and sulfur recovery units. Products from auxiliary facilities (e.g., clean water, steam, and process heat) are required by most process units throughout a refinery.

f. Emissions from Refinery Processing

These primary process units, minor process units, auxiliary equipment (boilers, turbines, heat exchangers, etc.), and other refinery activities (such as truck and loader traffic) emit a variety of criteria pollutants, toxic pollutants (toxic air contaminants), and climate pollutants (greenhouse gases). Other sources of emissions include waste water treatment, tanks, leaking equipment, pressure release devices, flares, marine terminals, and product loading, which are collectively subject to at least ten different Air District regulations. (A more detailed discussion on refinery emissions is provided below is subsection 3.)

2. PETROLEUM CRUDE OIL

Petroleum crude oil consists of a complex mixture of hydrocarbon compounds with smaller amounts of impurities, including sulfur, nitrogen, oxygen, a variety of toxic compounds, organic acids, and metals (e.g., iron, copper, nickel, and vanadium). Crude oil is most often characterized by the oil's density (light to heavy) and sulfur content (sweet to sour). A more detailed explanation of these terms and others used to describe crude oil follows below.

Each of the properties described below is required to be included in the periodic monthly Crude Slate Report described in Regulation 12, Rule 15 (Rule 12-15) because each relates to emissions of air pollutants. The purpose of the crude slate reporting in Rule 12-15 is to establish a baseline crude slate for each of the refineries and then to track changes in that crude slate, along with improved emissions data, to monitor the relationship between crude slate and emissions from the refineries.

a. API Gravity

The industry standard measure for crude oil density is American Petroleum Institute (API) gravity, which is expressed in units of degrees, and which is inversely related to density (i.e., a lower API gravity indicates higher density; a higher API gravity indicates lower density). Refineries convert crude oils to gaseous products (propane gas for sale and "fuel gas" that is consumed at the refinery), high-value transportation fuels (gasoline, diesel and jet fuel) and lower-value heavy oils (such as "bunker fuel" that is used by ocean-going vessels). Crude oils with higher API gravity can theoretically be converted to higher-value light products with less processing than crude oils with lower API gravity. Refinery operators have asserted that, although this may suggest that a refinery operator would prefer to use high API gravity crudes exclusively, this is not the case because each refinery is designed and equipped to process crude oil with API gravity in a certain range. Processing crude oil outside of the design range—even if it is "light" crude—will result in processing bottlenecks that reduce the overall efficiency of the refinery.

b. Sulfur Content ("Sweet" and "Sour" Crude)

Sulfur is an impurity that occurs in crude oil and arrives in various forms including: elemental sulfur (S), hydrogen sulfide (H_2S), carbonyl sulfide (COS), inorganic forms, and most importantly, organic forms that include: mercaptans, sulfides, and polycyclic sulfides. "Sweet crude" is commonly defined as crude oil with sulfur content less than 0.5 percent, while "sour crude" has sulfur content greater than 0.5 percent. Sweet crude is more desirable because sulfur must be removed from the crude oil to produce more valuable refined products such as gasoline, diesel and aviation fuels.

c. Vapor Pressure

Vapor pressure is a measure of crude oil volatility. Higher vapor pressure crude oil contains greater amounts of light Volatile Organic Carbon (VOC) compounds.

d. BTEX (Benzene, Toluene, Ethylbenzene, Xylene) Content

BTEX content is a measure of the benzene, toluene, ethylbenzene, and xylene content in crude oil.

e. Metals (Iron, Nickel and Vanadium) Content

The metals content of crude oil indicates both the solids contamination of crude oil and the potential for organic metals compounds in the heavy gas oil component of crude oil.

f. Possible Changes in Emissions Due to Changes in Crude Oil

In the past several years, new sources of crude oil—including American shale oil and Canadian tar sands-derived oil—have become available to petroleum refineries in North America, including Bay Area refineries. The crude oil derived from shale, now accessible because of technological improvements in hydraulic fracturing ("fracking"), tends to be light and sweet. However, this crude oil has higher VOC and H_2S content than some other crude oils. Crude oil from tar sands, currently under development in the Canadian province of Alberta, tends to be heavy and sour.

To maximize production, refineries are designed to process crude oils within a certain range of compositions—often referred to as “crude window.” For example, a refinery that is designed to process more sour crude must have the capacity to remove large amounts of sulfur from the crude oil, while a refinery designed to process sweet crude does not require as much sulfur processing capacity. Bay Area refineries traditionally process heavier and more sour crude oils because, for many years, much of the crude supply has been heavy sour crude from Kern County and medium sour crude from Alaska. The refineries would likely need to make changes to their facilities to accommodate different sources of crude oil with different compositions to maintain current production levels.

It is anticipated that refineries will update and/or modify their equipment to meet stricter regulatory fuel requirements and potentially to process crude oil from different sources. Rule 12-15 was adopted to monitor the key data so that staff can determine if emissions changes are potentially driven by changes in crude slate. The intent of Rule 12-16 is to discourage or prevent refineries in the Bay Area from making changes that would lead to increases in emissions of certain pollutants. There are permit limits to prevent increases in criteria pollutants from equipment already operating and state, federal and Air District regulatory requirements in place to ensure that emissions of criteria pollutants in the region do not increase as equipment is updated or new equipment and processes are added.

3. AIR POLLUTANTS EMITTED FROM PETROLEUM REFINERIES

Air pollutants are categorized and regulated based on their properties and there are three primary categories of regulated air pollutants: (1) criteria pollutants; (2) toxic pollutants (toxic air contaminants, which in federal programs are referred to as "hazardous air pollutants"); and (3) climate pollutants (e.g., greenhouse gases). Additional categories of air pollutants include odorous compounds and visible emissions, although these are most often also components of one or more of the three primary categories of regulated air pollutants listed above.

a. Criteria Pollutants

Criteria pollutants have regional or basin-wide impacts and are emissions for which ambient air quality standards (AAQS) have been established, or are atmospheric precursors to such air pollutants (i.e., they participate in photochemical reactions to form a criteria pollutant, such as ozone). The AAQS are air concentration–based standards that are established to protect public health and welfare. The U.S. Environmental Protection Agency (EPA) sets AAQS on a national basis (National Ambient Air Quality Standards, or NAAQS), and CARB sets AAQS for the state of California (California Ambient Air Quality Standards, or CAAQS). Although there is some variation in the specific pollutants for which NAAQS and CAAQS have been set, the term "criteria pollutants" generally refers to the following:

- Carbon monoxide (CO);
- Nitrogen dioxide (NO_2) and oxides of nitrogen (NO_X);
- Particulate matter (PM) in two size ranges—diameter of 10 micrometers or less (PM_{10}), and diameter of 2.5 micrometers or less ($PM_{2.5}$);
- Precursor Organic Compounds (POCs) for the formation of ozone and $PM_{2.5}$; and
- Sulfur dioxide (SO_2).

Each of these criteria pollutants is emitted by petroleum refineries.

b. Toxic Pollutants

Toxic pollutants, also known as toxic air contaminants (TACs), have localized impacts and are emissions for which AAQS generally have not been established, but that nonetheless may result in human health risks. TACs generally are emitted in much lower quantities than criteria pollutants, and may vary markedly in their relative toxicity (i.e., some TACs cause health impacts at lower concentrations than other TACs). The state list of TACs currently includes approximately 190 separate chemical compounds and groups of compounds. TACs emitted from petroleum refineries include volatile organic TACs (e.g., acetaldehyde, benzene, 1,3-butadiene, formaldehyde, and xylenes); semi-volatile and non-volatile organic TACs (e.g., benzo(a)pyrene, chlorinated dioxin/furans, cresols, and naphthalene); metallic TACs (e.g., compounds containing arsenic, cadmium, chromium, mercury, and nickel); and inorganic TACs (e.g., chlorine, hydrogen sulfide, and hydrogen chloride). These pollutants are not addressed by Rule 12-16. The Air District is proposing to address TAC emissions from refineries and other sources through draft Regulation 11, Rule 18: Reduction of Risk from Air Toxic Emissions at Existing Facilities.

c. Climate Pollutants

Climate pollutants (greenhouse gases or GHGs) are emissions that contribute to global anthropogenic climate change. Carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), and three groups of fluorinated compounds (hydrofluorocarbons, or HFCs; perfluorocarbons, or PFCs; and sulfur hexafluoride, or SF_6) are the major anthropogenic GHGs, and are regulated under the federal Clean Air Act and the California Global Warming Solutions Act (AB 32). The climate pollutants emitted from petroleum refineries include CO_2, CH_4, and N_2O.

d. Refinery Air Pollution in Context

Refineries are a significant source of air pollutants in general. In the counties where the refineries are located, their emissions can be more significant on a percentage basis, especially for SO_2 and $PM_{2.5}$.

The tables below are based on 2012 emissions data and do not account for the benefits of recent Air District rulemaking that are projected to reduce refinery criteria pollutant emissions by approximately 17 percent. They also do not include the benefits of rules under development to reduce SO_2 emissions from refineries. The tables compare refinery emissions of key criteria pollutants to other emissions both in the Bay Area and in Contra Costa and Solano counties where the refineries are located.

Table 1: Bay Area Emissions of Relevant Pollutants by Source Category

Source Category	**Emissions**							
	$PM_{2.5}$		**Anthropogenic ROG**		**NO_X**		**SO_2**	
	(tons/yr.)	%	(tons/yr.)	%	(tons/yr.)	%	(tons/yr.)	%
Refineries	1,524	9	5,399	6	4,248	4	2,890	41
Coke Calcining	28	0.2	0.2	< 0.1	239	0.2	1,242	17
Cement Plant	23	0.1	40	< 0.1	2,170	2	912	13
Major Industrial	1,839	11	17,639	18	5,765	5	581	8
Residential/Commercial	5,519	34	27,862	28	5,531	5	326	5
Agricultural	471	3	2,049	2	0	0	0	0
Miscellaneous	986	6	116	0.1	10	< 0.1	0	0
Mobile Sources	5,945	36	44,659	46	91,473	83.6	1,168	16
Total Emissions	**16,335**	**100%**	**97,763**	**100%**	**109,436**	**100%**	**7,119**	**100%**

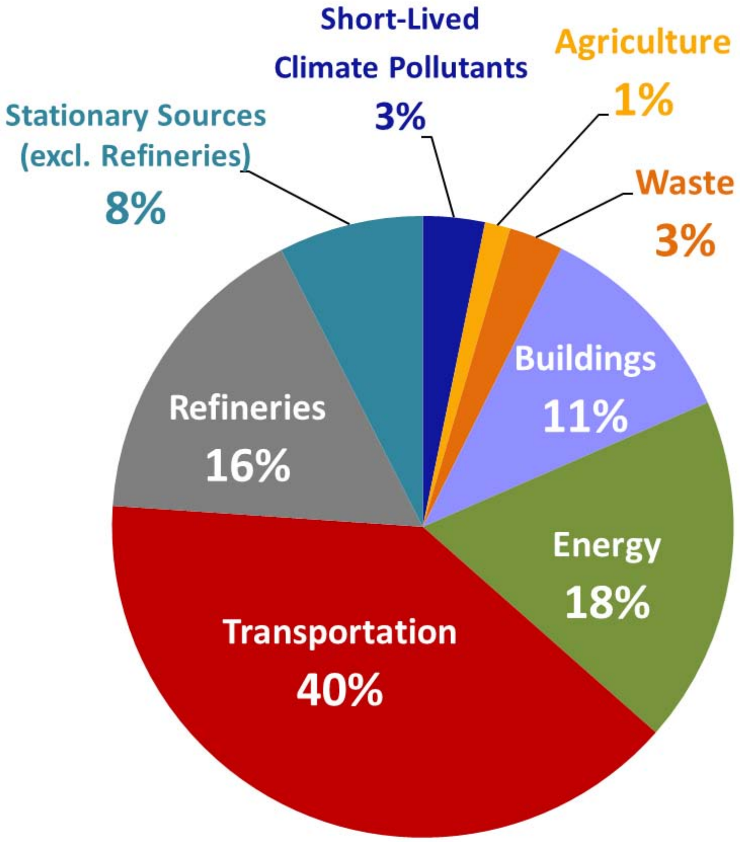
Table 2: Emissions of Relevant Pollutants by Source Category for Contra Costa and Solano Counties

Source Category	Emissions							
	$PM_{2.5}$		Anthropogenic ROG		NO_X		SO_2	
	(tons/yr.)	%	(tons/y.r)	%	(tons/yr.)	%	(tons/yr.)	%
Refineries	1,524	29	5,399	23	4,248	17	2,890	63
Coke Calcining	28	1	0.2	0.001	239	1	1,242	27
Cement Plant	0	0	0	0	0	0	0	0
Major Industrial	569	11	3,383	14	2,131	8	85	2
Residential/Commercial	1,548	29	5,649	24	1,122	4	49	1
Agricultural	97	2	369	2	0	0	0	0
Miscellaneous	294	6	20	0.1	2	0	0	0
Mobile Sources	1,212	23	9,041	38	17,703	70	296	6
Total	**5,272**	**100%**	**23,859**	**100%**	**25,445**	**100%**	**4,563**	**100%**

1. Emissions from biogenic sources and accidental fires are not included in this inventory. Mobile emissions include shipping emissions within 3 nautical miles of the Bay Area coastline.
2. $PM_{2.5}$ emissions for the Refineries category include condensable and filterable PM. Condensable PM data are not available for other source categories at this time.

Refineries are also a significant source of GHG emissions. They produce about two-thirds of the industrial GHG emissions in the Bay Area. Mobile sources are the largest source of GHG emissions overall. Refining and use of transportation fuels together account for 56 percent of GHG emissions in the Bay Area.

Figure 2: Bay Area GHG Emissions by Economic Sector for Year 2013



1. Emissions for the energy sector include electricity generation and co-generation for the Bay Area region, including imported electricity.
2. Emissions associated with fuel usage (solid, liquid and gas) are apportioned according to its use; residential and commercial fuel usage is attributed to the buildings sector while industrial fuel usage is accounted for in the stationary sources or refinery sectors.

B. Regulation of Air Pollutants from Petroleum Refineries

1. CRITERIA POLLUTANTS

Bay Area refineries are subject to various air quality regulations that have been adopted by the Air District, CARB, and the EPA. These regulations contain standards that ensure emissions are effectively controlled, including:

- Requiring the use of specific emission control strategies or equipment (e.g., the use of floating roofs on tanks for VOC emissions);
- Requiring that emissions generated by a source be controlled by at least a specified percentage (e.g., 95% control of VOC emissions from pressure relief devices);
- Requiring that emissions from a source not exceed specific concentration levels (e.g., 100 parts per million [ppm] by volume of VOC for equipment leaks unless those leaks are repaired within a specific timeframe; 250 ppm by volume SO_2 in exhaust gases from sulfur recovery units; 1,000 ppm by volume SO_2 in exhaust

gases from catalytic cracking units);

- Requiring that emissions not exceed certain quantities for a given amount of material processed or fuel used at a source (e.g., 0.033 pounds NO_X per million BTU of heat input, on a refinery-wide basis, for boilers, process heaters, and steam generators);
- Requiring that emissions be controlled sufficiently so that concentrations beyond the facility's property are below specified levels (e.g., 0.03 ppm by volume of hydrogen sulfide [H_2S] in the ambient air);
- Requiring that emissions from a source not exceed specified opacity levels based on visible emissions observations (e.g., no more than 3 minutes in any hour in which emissions are as dark or darker than No. 1 on the Ringelmann Smoke Chart); and
- Requiring that emissions be minimized by the use of all feasible prevention measures (e.g., flaring prohibited unless it is in accordance with an approved Flare Minimization Plan).

Air quality rules generally do not expressly limit mass emissions (e.g., pounds per year of any specific air pollutant) from affected equipment unless that equipment was constructed or modified after March 7, 1979, and was subject to the Air District's New Source Review (NSR) rule. All Bay Area refineries have "grandfathered" emission sources that were not subject to NSR but are generally regulated by equipment-specific Air District regulations or operational conditions contained in Air District permits. As a result, none of the Bay Area refineries have overall mass emission limits that apply to the entire refinery as they are defined in Rule 12-16. Nonetheless, mass emissions of regulated air pollutants from Bay Area refineries are tracked at the source level, and these mass emissions generally have been substantially reduced over the past several decades.

Air pollutant emissions from Bay Area petroleum refineries have been regulated for more than 50 years, with most of the rules and regulations adopted following enactment of the 1970 Clean Air Act amendments. The Air District has the primary responsibility to regulate "stationary sources" of air pollution in the Bay Area, and the Air District has adopted many rules and regulations that apply to petroleum refineries.

2. TOXIC POLLUTANTS

The Air District uses three approaches to reduce TAC emissions and to reduce the health impacts resulting from TAC emissions: (1) Specific rules and regulations, including federal, state, and Air District regulation; (2) Preconstruction review; and (3) the AB 2588 Air Toxics "Hot Spots" Program. Rule 12-16 would not impact existing regulations of these pollutants as it does not directly address them.

3. ACCIDENTAL RELEASE REGULATION

In addition to Air District regulations, petroleum refineries are also subject to regulatory programs that are intended to prevent accidental releases of regulated substances. Accidental release prevention programs in California are implemented and enforced by local administering agencies, which, in the case of the Bay Area refineries, are Solano County (for the Valero Refining Company) and Contra Costa County (for Chevron Products Company, Phillips 66 Company, Shell Martinez Refinery, and Tesoro Refining and Marketing Company).

The primary regulatory programs of this type are based on requirements in the amendments to the1990 Clean Air Act as follows: (1) the Process Safety Management (PSM) program, which focuses on protecting workers, and which is administered by the U.S. Occupational Safety & Health Administration (OSHA); and (2) the Accidental Release Prevention program (commonly referred to as the Risk Management Program, or RMP), which focuses on protecting the public and the environment, and which is administered by EPA. Bay Area refineries are subject to Cal/OSHA's PSM program, which is very similar to the federal OSHA program focusing on worker safety, but with certain more stringent state provisions. Bay Area refineries are subject to the California Accidental Release Prevention (CalARP) Program, which is very similar to EPA's RMP program to limit exposure of the public, but with certain more stringent State provisions. In addition, Contra Costa County and the City of Richmond have both adopted an Industrial Safety Ordinance (ISO). These ISOs are very similar to CalARP requirements, but with certain more stringent local provisions.

4. AIR DISTRICT RULES AFFECTING REFINERIES

The following is a partial list of the air pollution rules and regulations that the Air District implements and enforces at Bay Area refineries:

- Regulation 1: General Provisions and Definitions
- Regulation 2, Rule 1: Permits, General Requirements
- Regulation 2, Rule 2: New Source Review
- Regulation 2, Rule 5: New Source Review of Toxic Air Contaminants
- Regulation 2, Rule 6: Major Facility Review (Title V)
- Regulation 6, Rule 1: Particulate Matter, General Requirements
- Regulation 6, Rule 5: Particulate Emissions from Refinery Fluidized Catalytic Cracking Units
- Regulation 8, Rule 1: Organic Compounds, General Provisions
- Regulation 8, Rule 2: Organic Compounds, Miscellaneous Operations
- Regulation 8, Rule 5: Storage of Organic Liquids
- Regulation 8, Rule 6: Terminals and Bulk Plants
- Regulation 8, Rule 8: Wastewater (Oil-Water) Separators
- Regulation 8, Rule 9: Vacuum Producing Systems
- Regulation 8, Rule 10: Process Vessel Depressurization
- Regulation 8, Rule 18: Equipment Leaks
- Regulation 8, Rule 28: Episodic Releases from Pressure Relief Devices at Petroleum Refineries and Chemical Plants
- Regulation 8, Rule 44: Marine Vessel Loading Terminals
- Regulation 9, Rule 1: Sulfur Dioxide

- Regulation 9, Rule 2: Hydrogen Sulfide
- Regulation 9, Rule 8: Nitrogen Oxides and Carbon Monoxide from Stationary Internal Combustion Engines
- Regulation 9, Rule 9: Nitrogen Oxides and Carbon Monoxide from Stationary Gas Turbines
- Regulation 9, Rule 10: Nitrogen Oxides and Carbon Monoxide from Boilers, Steam Generators and Process Heaters in Petroleum Refineries
- Regulation 9, Rule 14: Petroleum Coke Calcining Operations
- Regulation 11, Rule 10: Cooling Towers
- Regulation 12, Rule 11: Flare Monitoring at Petroleum Refineries
- Regulation 12, Rule 12: Flares at Petroleum Refineries
- Regulation 12, Rule 15: Petroleum Refinery Emissions Tracking
- 40 CFR Part 60, Subpart J: Standards of Performance for Petroleum Refineries (NSPS)
- 40 CFR Part 61, Subpart FF: Benzene Waste Operations (NESHAP)
- 40 CFR Part 63, Subpart CC: Petroleum Refineries (NESHAP)
- 40 CFR Part 63, Subpart UUU: Petroleum Refineries: Catalytic Cracking, Catalytic Reforming, and Sulfur Plant Units (NESHAP)
- State Airborne Toxic Control Measure for Stationary Compression Ignition (Diesel) Engines (ATCM).

III. REQUIREMENTS

Explanations of the various provisions of Rule 12-16 are provided below.

A. Applicability and Exemptions

Rule 12-16 would apply to the five large refineries in the Bay Area:

1. Chevron Products Company, Richmond (BAAQMD Plant #10)
2. Phillips 66 Company—San Francisco Refinery, Rodeo (BAAQMD Plant #21359)
3. Shell Martinez Refinery, Martinez (BAAQMD Plant #11)
4. Tesoro Refining and Marketing Company, Martinez (BAAQMD Plant #14628)
5. Valero Refining Company—California, Benicia (BAAQMD Plant #12626) and associated Asphalt Plant (BAAQMD Plant #13193)

The rule would also apply to three support facilities:

1. Air Products and Chemicals hydrogen plant, Martinez (BAAQMD Plant #10295)
2. Air Liquide hydrogen plant, Rodeo (BAAQMD Plant #17419)
3. Martinez Cogen, L.P. (BAAQMD Plant #1820)

Small oil refineries less than 5,000 bpd capacity would be exempt from the requirements of this rule.

B. Definitions

Rule 12-16 definitions are identical to the definitions in related Rule 12-15.

C. Standards

Rule 12-16 sets emission limits for each affected facility. These emission limits were established by analyzing emissions to establish a baseline five-year period. Criteria pollutant emissions were analyzed for calendar years 2010, 2011, 2012, 2013, and 2014, as this was the most recent five-year period for which the Air District has complete criteria pollutant emissions data. Emission reductions of approximately 17 percent garnered by recent regulatory action would not be included in the baseline data since these reductions will occur after 2014. GHG emissions were analyzed for calendar years 2011, 2012, 2013, 2014, and 2015, as this was the most recent five-year period for which CARB has released GHG emissions data. The rule would then establish an emission limit that is seven percent higher than the highest emission rate during the baseline period. The methodology used to establish the emissions limits is presented in Appendix A.

1. GREENHOUSE GASES

- Each facility must provide GHG emissions to CARB as part of CARB's Mandatory Reporting of Greenhouse Gas Emissions Requirements (MRR). GHG Emissions Inventory information for each year was obtained from an Excel spreadsheet available on the CARB website,[1] using the entries under "Calculated Covered Emissions, metric tons CO2e."
- The highest annual GHG emissions for the five-year baseline period is used to establish the 2011 – 2015 Baseline shown in Table 12-16-301 in the rule language, and repeated below for clarity.
- Emissions limits are increased by seven percent over the baseline to provide what CBE contends is adequate operating flexibility and to account for normal year-to-year variations in emissions.
- Annual emission limits for each facility are shown below.

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[1] https://www.arb.ca.gov/cc/reporting/ghg-rep/reported-data/ghg-reports.htm

Table 12-16-301: GHG Emission Limits

Facility	**2011–2015 Baseline**[1] (metric tons CO_2e/yr.)	**Seven Percent Allowance for Operating Variation** (metric tons CO_2e/yr.)	**Emissions Limits** (metric tons CO_2e/yr.)
Chevron Refinery A-0010	4.46 M	312 K	4.77 M
Shell Refinery A-0011	4.26 M	298 K	4.56 M
Phillips 66 Refinery A-0016	1.50 M	105 K	1.61 M
Tesoro Refinery B-2758/2759	2.44 M	171 K	2.61 M
Valero Refinery, B-2626 & Asphalt Plant, B-3193	2.94 M	206 K	3.15 M
Martinez Cogen LP A-1820	421 K	29.5 K	450 K
Air Liquide H2 Plant B7419	885 K	61.9 K	947 K
Air Products H2 Plant B-0295	271 K	19.0 K	290 K

M = Millions, K = Thousands

[1] Maximum annual emissions from 2011 – 2015 baseline years, California Air Resources Board Emissions Inventory: Mandatory GHG Reporting - Reported Emissions, ARB Calculated Covered Emissions (metric tons CO_2e)

2. PARTICULATE MATTER - < 10 MICRONS

- Air District criteria pollutant PM_{10}, $PM_{2.5}$, NO_x and SO_2 emissions inventories for each year during the baseline period were used as the basis for the emissions limits.
- PM_{10} emissions from flare and cooling towers were excluded from the emissions inventories at CBE's request. They were concerned that additional restrictions on flare emissions could pose a safety problem. They asked to exclude cooling tower emissions since these emissions are unrelated to combustion.
- The highest annual PM_{10} emissions for the five-year baseline period is used to establish the 2010 – 2014 Baseline shown in Table 12-16-302 in the rule language, and repeated in this report for clarity.
- Emissions limits are increased by seven percent over the baseline to provide what CBE contends is adequate operating flexibility.
- Annual emission limits for each facility are shown below.

Table 12-16-302: Particulate Matter (PM_{10}) Emission Limits

Facility	**2010–2014 Baseline** (tons/yr.)	**Seven Percent Allowance for Operating Variation** (tons/yr.)	**Emissions Limits** (tons/yr.)
Chevron Refinery A-0010	491	34.4	525
Shell Refinery A-0011	550	38.5	589
Phillips 66 Refinery A-0016	77.7	5.44	83.1
Tesoro Refinery B-2758/2759	90.7	6.35	97.0
Valero Refinery, B-2626 & Asphalt Plant, B-3193	125	8.75	134
Martinez Cogen LP A-1820	17.6	1.23	18.8
Air Liquide H2 Plant B7419	16.1	1.13	17.2
Air Products H2 Plant B-0295	9.71	0.68	10.4

3. PARTICULATE MATTER - < 2.5 MICRONS

- The highest annual $PM_{2.5}$ emissions for the five-year baseline period is used to establish the 2010 – 2014 Baseline shown in Table 12-16-303 in the rule language, and repeated in this report for clarity.
- $PM_{2.5}$ emissions from flare and cooling towers were excluded for reasons explained above.
- Emissions limits are increased by seven percent over the baseline to provide what CBE contends is adequate operating flexibility.
- Annual emission limits for each facility are shown below.

Table 12-16-303: Particulate Matter ($PM_{2.5}$) Emission Limits

Facility	**2010–2014 Baseline** (tons/yr.)	**Seven Percent Allowance for Operating Variation** (tons/yr.)	**Emissions Limits** (tons/yr.)
Chevron Refinery A-0010	469	32.8	502
Shell Refinery A-0011	463	32.4	495
Phillips 66 Refinery A-0016	70.1	4.91	75.0
Tesoro Refinery B-2758/2759	72.6	5.08	77.7
Valero Refinery, B-2626 & Asphalt Plant, B-3193	124	8.72	133
Martinez Cogen LP A-1820	17.6	1.23	18.8
Air Liquide H2 Plant B7419	15.0	1.06	16.1
Air Products H2 Plant B-0295	9.06	0.63	9.69

4. NITROGEN OXIDES

- The highest annual NO_x emissions for the five-year baseline period is used to establish the 2010 – 2014 Baseline shown in Table 12-16-304 in the rule language, and repeated in this report for clarity.
- NO_x emissions from flares were excluded for reasons explained above.
- Emissions limits are increased by seven percent to provide what CBE contends is adequate operating flexibility.
- Annual emission limits for each facility are shown below.

Table 12-16-304: Nitrogen Oxide (NO_x) Emission Limits

Facility	**2010–2014 Baseline** (tons/yr.)	**Seven Percent Allowance for Operating Variation** (tons/yr.)	**Emissions Limits** (tons/yr.)
Chevron Refinery A-0010	907	63.5	970
Shell Refinery A-0011	998	69.9	1.07 K
Phillips 66 Refinery A-0016	270	18.9	289
Tesoro Refinery B-2758/2759	949	66.4	1.02 K
Valero Refinery, B-2626 & Asphalt Plant, B-3193	1.20 K	84.0	1.29 K
Martinez Cogen LP A-1820	111	7.77	119
Air Liquide H2 Plant B7419	12.7	0.90	13.8
Air Products H2 Plant B-0295	8.25	0.58	8.83

K = Thousands

5. SULFUR DIOXIDE

- The highest annual SO_2 emissions for the five-year baseline period is used to establish the 2010 – 2014 Baseline shown in Table 12-16-305 in the rule language, and repeated in this report for clarity.
- SO_2 emissions from flares were excluded for reasons explained above.
- Emissions limits are increased by seven percent to provide what CBE contends is adequate operating flexibility.
- Annual emission limits for each facility are shown below.

Table 12-16-305: Sulfur Dioxide (SO_2) Emission Limits

Facility	**2010–2014 Baseline** (Tons/yr.)	**Seven Percent Allowance for Operating Variation** (Tons/yr.)	**Emissions Limits** (Tons/yr.)
Chevron Refinery A-0010	368	25.8	394
Shell Refinery A-0011	1.36 K	95.2	1.46 K
Phillips 66 Refinery A-0016	365	25.6	391
Tesoro Refinery B-2758/2759	602	42.1	644
Valero Refinery, B-2626 & Asphalt Plant, B-3193	65.1	4.56	69.7
Martinez Cogen LP A-1820	2.15	0.15	2.30
Air Liquide H2 Plant B7419	2.35	0.16	2.51
Air Products H2 Plant B-0295	2.70	0.19	2.89

K = Thousands

6. ADMINISTRATIVE REQUIREMENTS

Rule 12-16 has no administrative requirements. Each refinery and support facility will report emissions based on the requirements in Rule 12-15, Section 401. The APCO will review and approve the annual emissions inventory per Rule 12-15, Section 402. Air District staff will then take the steps needed to exclude flare and cooling tower emissions from the annual emissions inventory, where needed. Refinery and support facility emissions for each pollutant, after exclusions, will be compared to the emissions limits established in Rule 12-16, Section 300. Determination of Compliance is described in the next section of this report.

The emissions limits shown for each pollutant in Rule 12-16, Section 300 will need to be adjusted for a variety of reasons:

- as emissions measurement methods improve,
- as emissions estimates for various process operations, startups, shutdowns, and malfunctions improve,
- as information regarding condensable particulate matter improves,
- as new regulations establish more restrictive limits on specific emissions sources, any resulting emission reductions (or associated increases) will be subtracted from (or added to) the emissions limits,
- as emissions data from cargo carriers become available, and those emissions are incorporated into the total facility emissions limits, and

- to account for any other improvements in emissions inventory methods and reporting that are not yet anticipated.

Staff considered building an emissions limit adjustment process into the Administrative Requirements section of Rule 12-16, but, based on discussions with CBE to ensure the language represented their concept, decided that transparency required Board of Director's approval of any adjusted emissions limits. Staff anticipates that Rule 12-16 will need to be amended regularly to include a variety of adjustments in the emissions limits, as described above.

Facility emissions limits for each pollutant would not be adjusted to accommodate any new projects that have been permitted through the New Source Review process governed by Regulation 2, Rule 2: New Source Review. Under current rules that apply to all facilities, projects permitted through the New Source Review process that result in emissions increases can offset those emissions increases with reductions elsewhere in the region. Rule 12-16 would, in effect, eliminate that option for refineries and would require all emission increases to be offset within the individual facility. This is one of the intended consequences of CBE's policy recommendation and staff believes may cause significant legal issues.

7. COMPLIANCE DETERMINATION

Compliance with Rule 12-16 is determined by comparing each facility's GHG, PM_{10}, $PM_{2.5}$, NO_x, and SO_2 emissions as set forth in the facility's inventory, after exclusions of flare and cooling tower emissions, with the emissions limits in Section 12-16-300. If the inventory emissions of each pollutant (after exclusions) are less than the limit, the facility complies. If the inventory emissions of any pollutant (after exclusions) exceeds the limit, the facility is out of compliance for the entire year and would be liable for a violation for each pollutant limit exceeded for each day of the calendar year. It would be unlikely that compliance determination could be made throughout the year, since adjustments to emission caps caused by changes in quantification and discussed previously would not be enacted until Board action is taken to codify changes in caps.

IV. EMISSIONS AND EMISSIONS REDUCTIONS

A. Petroleum Refining Emissions Impact

Emissions from refinery equipment depend on the specific equipment and how pollutants are emitted at that equipment. Some equipment has defined emissions points (e.g. stack or vent) while others do not.

In the above sections, specific equipment (e.g. crude unit, fluid catalytic cracker, coker, hydrogen plant, etc.) were mentioned as affected by key crude oil and petroleum feedstock parameters. Depending on the equipment, an affected unit may directly emit pollutant in a stack or indirectly through either equipment leaks or unexpected failure.

A summary of the refinery equipment and emissions points is listed in Table 3.

Table 3 – Summary of Refinery Equipment by Emission Points and Pollutant

Refinery Equipment	Emission Point	Pollutants
Storage Tanks		VOCs, toxics
External Floating Roof Tank	Tank seals, guide poles, gauge poles, pressure relief devices, drains	
Internal Floating Roof Tank	Pressure relief devices, hatches	
Geodesic Dome Tank	Pressure relief devices, hatches	
Fixed Roof Tank	Pressure relief devices, hatches	
Sphere	Pressure relief devices	
Combustion Equipment		CO_2, NOx, SO_2, PM,
Boiler	Stack	
Furnace/Process Heater	Stack	
Gas Turbine	Stack	
Stationary Engines	Stack	
Flares	Open top	
Thermal Oxidizers	Stacks	
Fugitive Equipment Leaks (at all refinery equipment)		VOCs, toxics
Valves	Valve stems	
Connection	Connection gaps	
Pump	Pump seals	
Compressor	Gaps	
Pressure Relief Device	Gaps in relief horn seat	
Drain	Opening	
Heat Exchanger/Cooling Tower	Holes in heat exchanger tubes and cooling tower water	VOCs, toxics
Process Units		CO_2, NOx, SO_2, PM,
Catalytic Reformer	Stack	
Hydrogen Plant	Stack	
Hydrocracker	Stack	
Fluid Catalytic Cracking Unit	Stack	
Delayed Coker	Stack	
Fluid Coker	Stack	
Flexicoker	Stack	
Solvent Deasphalting	Stack	
Sulfur Recover Unit/Sulfur Plant	Stack	
Process Units (excluding combustion sources and fugitive emissions)		VOCs, toxics, PM
Crude Unit	None	
Gas Plant	None	
Isomerization	None	
Polymerization	None	
Alkylation	None	
Hydrotreaters	None	
Loading Racks		VOCs, toxics, PM
Rail Loading Rack	Pressure relief devices, loading arms	
Truck Loading Rack	Pressure relief devices, loading arms	
Marine Loading Rack	Pressure relief devices, loading arms	
Vapor Recovery	Stack, pressure relief devices	
Wastewater Treatment		VOCs, toxics
Oil Water Separator	Hatches	

Refinery Equipment	Emission Point	Pollutants
Oxidation Pond	Surface area	
Wetland Marsh	Surface area	
Marine Wharf		VOCs, toxics, PM, NOx, SO_2, CO_2
Tug Boat	Stack	
Marine Vessel	Stack, hatches	
Vapor Recovery	Stack, pressure relief devices	
Rail	Stack, hatches, pressure relief devices	VOCs, toxics, PM, NOx, SO_2, CO_2

B. Baseline Emissions

The Air District has established a baseline emissions inventory that shows baseline emissions for pollutants targeted by Rule 12-16: GHGs, PM (including directly-emitted filterable PM and condensable PM), NOx, and SO_2. It includes emissions from petroleum refinery processes (e.g., feedstock and product handling, petroleum separation, and conversion and treating processes) as well as from auxiliary facilities such as hydrogen production, sulfur recovery, and power plants. Calendar years 2010 through 2014 were chosen as the baseline years for PM_{10}, $PM_{2.5}$, NO_X, and SO_2 because this is the most recent period for which the Air District has complete emissions data. Calendar years 2011 through 2015 were chosen as the baseline years for GHGs because this is the most recent period for which CARB has released GHG emissions data from their MMR program.

Chevron / A0010

Pollutant	Annual Emissions (tons/year)						
	2010	**2011**	**2012**	**2013**	**2014**	**2015**	**Maximum**
PM_{10}	455	491	426	450	456	–	**491**
$PM_{2.5}$	434	469	407	428	436	–	**469**
NO_X	833	870	907	828	657	–	**907**
SO_2	365	368	334	320	360	–	**368**

Pollutant	Annual Emissions (millions of MT CO_2e/year)						
	2010	**2011**	**2012**	**2013**	**2014**	**2015**	**Maximum**
GHG	–	4.46	3.95	3.91	4.12	4.42	**4.46**

Note: CY 2015 data for criteria pollutant emissions are not currently available.

Phillips 66 / A0016

Pollutant	Annual Emissions (tons/year)						
	2010	**2011**	**2012**	**2013**	**2014**	**2015**	**Maximum**
PM_{10}	50.9	47.3	47.7	77.7	75.9	–	**77.7**
$PM_{2.5}$	50.7	47.3	47.5	70.1	68.3	–	**70.1**
NO_X	270	266	262	229	222	–	**270**
SO_2	365	316	316	349	354	–	**365**

Pollutant	Annual Emissions (millions of MT CO_2e/year)						
	2010	**2011**	**2012**	**2013**	**2014**	**2015**	**Maximum**
GHG	–	1.50	1.32	1.36	1.28	1.32	**1.50**

Note: CY 2015 data for criteria pollutant emissions are not currently available.

Shell / A0011

Pollutant	Annual Emissions (tons/year)						
	2010	**2011**	**2012**	**2013**	**2014**	**2015**	**Maximum**
PM_{10}	434	419	400	431	550	–	**550**
$PM_{2.5}$	407	390	371	401	463	–	**463**
NO_X	998	950	868	928	844	–	**998**
SO_2	1151	1242	1073	1360	1055	–	**1360**

Pollutant	Annual Emissions (millions of MT CO_2e/year)						
	2010	**2011**	**2012**	**2013**	**2014**	**2015**	**Maximum**
GHG	–	4.26	4.06	4.19	3.97	4.13	**4.26**

Note: CY 2015 data for criteria pollutant emissions are not currently available.

Tesoro / B2758

Pollutant	Annual Emissions (tons/year)						
	2010	**2011**	**2012**	**2013**	**2014**	**2015**	**Maximum**
PM_{10}	70.0	80.4	77.3	85.9	90.7	–	**90.7**
$PM_{2.5}$	63.6	63.4	62.0	67.6	72.6	–	**72.6**
NO_X	694	710	683	949	945	–	**949**
SO_2	405	602	510	586	554	–	**602**

Pollutant	Annual Emissions (millions of MT CO_2e/year)						
	2010	**2011**	**2012**	**2013**	**2014**	**2015**	**Maximum**
GHG	–	2.40	2.09	2.44	2.33	2.06	**2.44**

Note: CY 2015 data for criteria pollutant emissions are not currently available.

Valero Refinery / B2626 and Asphalt Plant / A0901

Pollutant	Annual Emissions (tons/year)						
	2010	**2011**	**2012**	**2013**	**2014**	**2015**	**Maximum**
PM_{10}	–	120	125	119	123	–	**125**
$PM_{2.5}$	–	120	124	119	123	–	**124**
NO_X	–	1041	1199	1081	1150	–	**1199**
SO_2	–	52.0	60.5	61.3	65.1	–	**65.1**

Pollutant	Annual Emissions (millions of MT CO_2e/year)						
	2010	**2011**	**2012**	**2013**	**2014**	**2015**	**Maximum**
GHG	–	2.64	2.94	2.74	2.71	2.84	**2.94**

Note: CY 2015 data for criteria pollutant emissions are not currently available.

Air Liquide / B7419

Pollutant	Annual Emissions (tons/year)						
	2010	**2011**	**2012**	**2013**	**2014**	**2015**	**Maximum**
PM_{10}	12.9	13.7	16.1	4.94	5.09	–	**16.1**
$PM_{2.5}$	12.1	12.9	15.0	4.61	4.75	–	**15.0**
NO_X	0.89	1.08	1.28	10.8	12.7	–	**12.7**
SO_2	1.54	1.75	2.32	2.35	0.61	–	**2.35**

Pollutant	Annual Emissions (millions of MT CO_2e/year)						
	2010	**2011**	**2012**	**2013**	**2014**	**2015**	**Maximum**
GHG	–	0.65	0.77	0.88	0.82	0.82	**0.88**

Note: CY 2015 data for criteria pollutant emissions are not currently available.

Air Products / B0295

Pollutant	Annual Emissions (tons/year)						
	2010	2011	2012	2013	2014	2015	Maximum
PM_{10}	7.96	9.60	8.02	9.71	0.29	–	**9.71**
$PM_{2.5}$	7.43	8.95	7.49	9.06	0.29	–	**9.06**
NO_X	4.04	5.04	5.74	8.25	7.47	–	**8.25**
SO_2	1.78	2.15	1.79	2.18	2.70	–	**2.70**

Pollutant	Annual Emissions (millions of MT CO_2e/year)						
	2010	2011	2012	2013	2014	2015	Maximum
GHG	–	0.26	0.22	0.27	0.26	0.20	**0.27**

Note: CY 2015 data for criteria pollutant emissions are not currently available.

Martinez Cogen / A1820

Pollutant	Annual Emissions (tons/year)						
	2010	2011	2012	2013	2014	2015	Maximum
PM_{10}	17.1	17.6	17.3	16.1	17.2	–	**17.6**
$PM_{2.5}$	17.0	17.6	17.2	16.1	17.1	–	**17.6**
NO_X	107	111	109	102	108	–	**111**
SO_2	2.08	2.15	2.11	1.97	2.10	–	**2.15**

Pollutant	Annual Emissions (millions of MT CO_2e/year)						
	2010	2011	2012	2013	2014	2015	Maximum
GHG	–	0.42	0.41	0.39	0.41	0.40	**0.42**

Note: CY 2015 data for criteria pollutant emissions are not currently available.

C. Emissions Reductions

Rule 12-16 sets maximum limits on annual emissions of various pollutants. However, the rule does not require reductions of any of the listed pollutants. Because of this, the rule will not achieve any emissions reductions; it would only prevent increases in emissions beyond those of the base years used to set the caps from affected facilities.

V. ECONOMIC IMPACTS

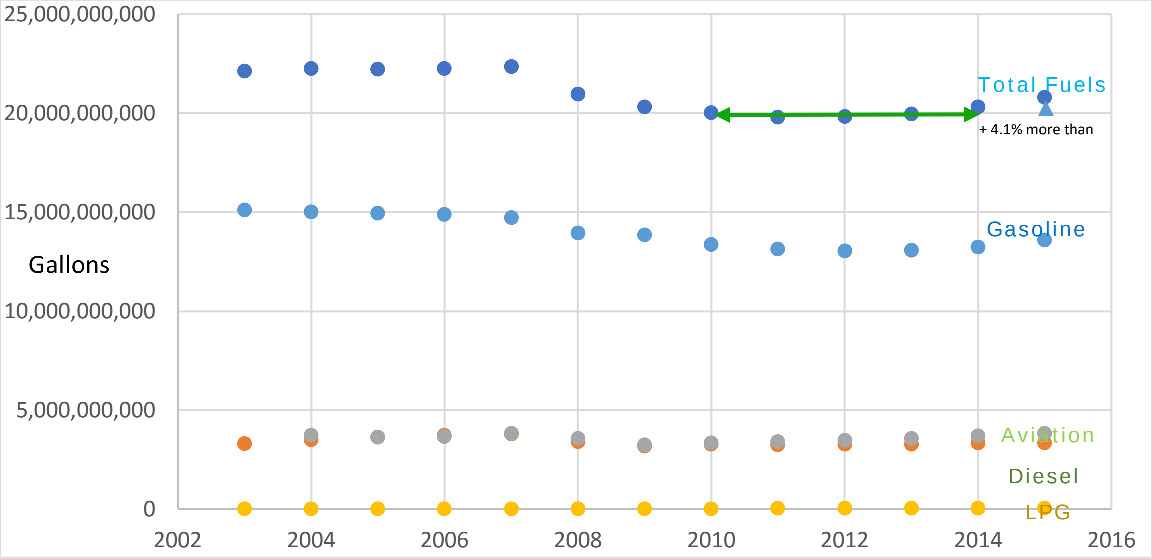
The California Health and Safety Code generally requires two different economic analyses for regulations planned and proposed by an air district. The first (H&S Code §40728.5) is a socioeconomic analysis of the adverse impacts of compliance with the proposed regulation on affected industries and business. The second analysis (H&S Code §40920.6) is an incremental cost effectiveness analysis when multiple compliance approaches have been identified by an Air District. Section 40920.6 applies only to rules requiring retrofit control technology. Since Rule 12-16 does not explicitly require installation of retrofit control technology, it is not possible to perform an incremental cost analysis.

In the case of draft Rule 12-16, there are two general scenarios to consider when evaluating the impact of capping refining emissions. In one general scenario, the refineries decide to make physical improvements to reduce emissions to allow for increases in refining capacity while staying below the cap. In the other general scenario, refineries elect to limit production to a level consistent with the cap.

In the first scenario, there will be economic and environmental impacts from the physical changes made at the refineries. For example, a refinery may elect to put in a wet scrubber to reduce PM and SO_2 emissions. Other abatement techniques can be employed reduce NOx emissions. This would have an impact on their profits which will be evaluated in the socioeconomic analysis. This would also have environmental impacts. A wet scrubber, for example, would have water supply and water quality impacts. Air District staff has developed a list of possible equipment changes that may be made in response to Rule 12-16 and evaluated those as part of the socioeconomic analysis and as part of the Environmental Impact Report (EIR) required under the California Environmental Quality Act (CEQA). This list was not intended to be comprehensive, but instead focused on the types of controls most likely to have significant environmental and economic impact.

In the second scenario, where the refineries limit their production to stay under the cap, there are potential costs to both the refineries and the larger economy. Whether these costs are realized depends on whether consumption of refinery products increases or decreases. Currently, consumption of refinery products is increasing, but it is still below peak demand. Figure 3, below, provides the relevant information.

Figure 3: California Refined Fuel Consumption



Source: http://www.energy.ca.gov/almanac/transportation_data/gasoline/, http://www.energy.ca.gov/almanac/petroleum_data/

Figure 3 shows trends in refined fuels consumption in California since 2003. Consumption peaked in 2008 at 22.3 billion gallons per year. CBE used the years 2010 through 2014 to determine the emission limits for Rule 12-16. The peak consumption in those years was 20.3 billion gallons per year. Fuel consumption increased to 20.8 billion gallons per year in 2015 and continues to increase.

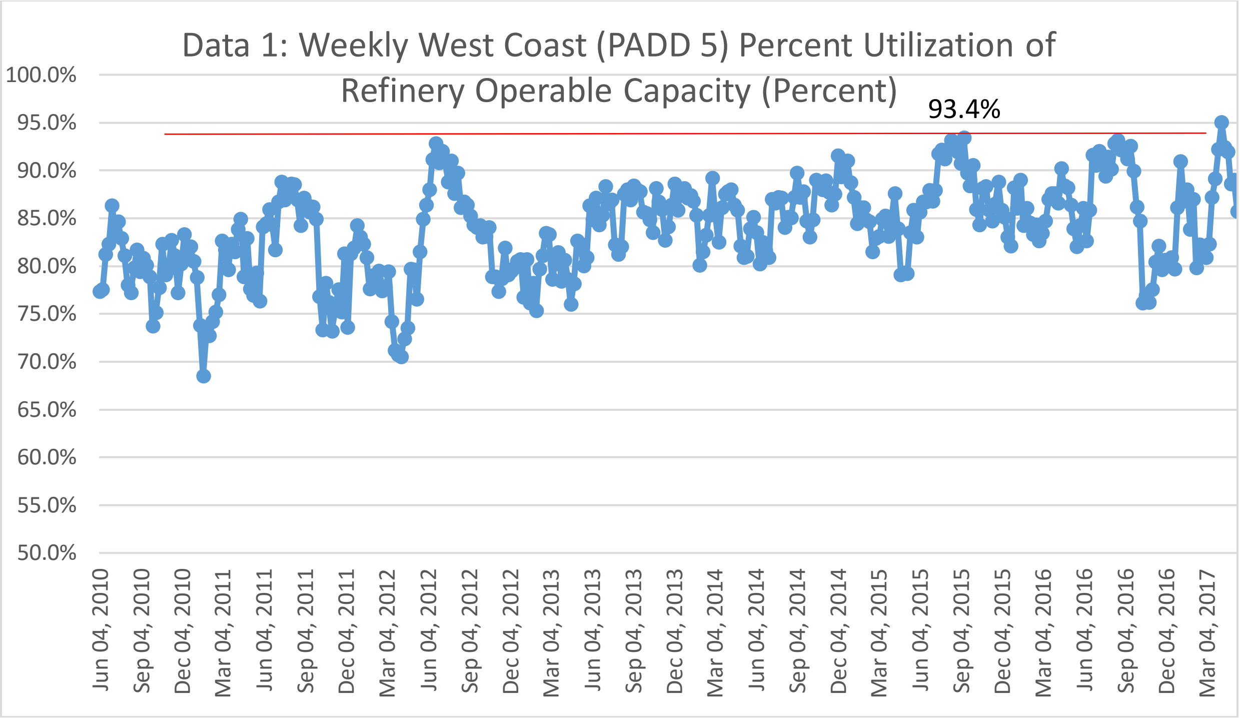
Staff also analyzed refinery operating utilization from the U.S. Energy Information Administration during the five-year baseline period from 2010 – 2014. This information is displayed on Figure 4, and is summarized in the Table 4 below:

Table 4: Average US West Coast Refinery Operating Utilization

Year	**Average Utilization** (%)	**Peak Utilization** (%)
2010 – 2014	82.6	93.4
2010	80.3	86.3
2011	80.7	88.8
2012	82.0	92.8
2013	83.4	88.6
2014	85.8	91.5
2015	86.5	93.4
2016	85.9	93.1

Note: Utilization data available for PADD 5 refineries, but not available for Bay Area refineries alone.

Figure 4: U.S. West Coast Refinery Utilization



Analysis of refinery utilization was performed to determine if the caps in Rule 12-16 would create a de facto production limitation for Bay Area refineries.

The data in Table 4 shows that the US West Coast refineries averaged 82.6 percent utilization during the 2010 – 2014 baseline period, ranging from an average utilization of 80.3 percent in 2010 to 85.8 percent in 2014. As shown in Figure 4, gasoline and total fuel consumption was relatively stable during this baseline period. Refinery utilization increased in 2015, driven by higher gasoline and total fuel consumption, and by a significant refinery outage.[2] Refining utilization continued to be high in 2016. Peak refining utilization appears to be about 93.5 percent. Given the few times when that peak was achieved, it's unlikely to be sustained over a long period due to unplanned outages and planned maintenance.

As described above, facility emissions limits were based on the highest annual emissions during the baseline period. During this period, refinery utilization averaged 82.6 percent, and the highest annual utilization during the baseline period was 85.8 percent. The facility emissions limits have been increased 7 percent to allow for normal year-to-year changes on an individual refinery basis. Assuming the Bay Area refineries are fairly represented by the overall PADD 5 refinery utilization, and that the refinery operators choose to comply with the cap by limiting production, the post-cap production capacity of Bay Area refineries will be limited to somewhere between (82.6 + 7 =) 89.6 percent to (85.8 + 7 =) 92.8 percent annual average utilization.

Assume Bay Area Refining Utilization PADD 5 Refinery Utilization
Emission based limit – low 82.6% + 7% = 89.6%
Emission based limit – high 85.8% + 7% = 92.8%
2015 PADD 5 utilization was 86.5%, and 2016 PADD 5 utilization was 85.9%
2017 YTD has been the highest PADD 5 utilization observed at 87.1 percent.

On average, the emissions limits do not appear to inhibit refining capacity considering Bay Area refineries as a group, since typical annual average utilization is 80 – 87 percent, and the emissions limits appear to establish production capacity limits at approximately 89 – 93 percent utilization. That is, the emission limits in Rule 12-16 appear to be consistent with the current maximum production capability of the refineries as a group. However, the emissions limits may impose effective production caps on individual refineries.

Given that the emission limits are consistent with the current production capacity for the refineries as a group; Air District staff do not expect the cap in Rule 12-16 to have significant impacts on the market for refined fuels if fuel consumption does not significantly increase or production capacity is not reduced by refinery closure or outage.

If the demand for refined fuels continues to increase or if overall statewide refinery capacity is reduced, the cap on individual refineries may end up being a significant constraint on the market. When the supply for fuels is constrained, the impacts can be

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[2] ExxonMobil's Torrance refinery was off-line from March 2015 – May 2016.

dramatic and felt statewide. In 2015, the ExxonMobil refinery in Torrance was offline for most of the year. This reduced refining production capacity in the state by roughly 10 percent. Because of this moderate reduction in supply, gasoline prices increased 27.6 cents over the typical cost of gasoline in California. The direct cost to the California economy was over $2 billion.[3] In addition, imports of refined products increased ten-fold, resulting in additional GHG emissions from shipping. CARB projects that gasoline consumption will decrease over time due to stricter fuel consumption standards and other factors. However, the trend since 2012 has been toward increasing consumption. If this trend continues, and refineries respond to the cap by limiting production, Rule 12-16 may eventually have a significant economic impact on the Bay Area and the rest of California. This would also be the case if statewide refinery capacity was significantly reduced due to a refinery closure or incident like the 2015 ExxonMobil incident.

A. SOCIOECONOMIC IMPACT ANALYSIS OF RULE 12-16

The economic analysis of Rule 12-16 considers two possible responses to the proposed emission limits. In one scenario, refineries will make improvements to allow for production to increase above current capacity. These improvements will have both economic and environmental impacts. In the other scenario, refineries will limit production to stay under the emissions limits. These two assumptions were used to determine the maximum possible impact of the rule. The refineries have other, lower-cost options that they could pursue to comply with the rule, such as improving the efficiency of their operations. The economic and environmental impacts of this response depend upon future demand for transportation fuels or reduction in overall refinery capacity. If demand decreases, as CARB projects, it is likely that there will be no impacts. If demand increases, as it has been since 2012, or statewide refinery capacity decreases, there could be significant economic impacts and potentially a net increase in GHG emissions due to Rule 12-16.

Scenario 1: Installation of a Wet Gas Scrubber

Of the eight potentially affected facilities, it is assumed that only three would possibly elect to install a wet gas scrubber to stay in compliance with the emissions limits of Rule 12-16 because these facilities operate fluidized catalytic cracking units (FCCU), which are significant sources of NOx, SO_2, and PM.

Cost of Compliance

In the event affected sources adopt physical improvements to comply with Rule 12-16, it is probably that affected sources will adopt one of two scrubbers, i.e. a FCCU non-regenerative scrubber or a FCCU regenerative scrubber. One FCCU non-regenerative scrubber with a flow rate of 275,000 dry standard cubic feet per minute (dscfm) annually costs $6,336,978. Of this amount, $5,170,880 is the annual capital cost associated with a non-regenerative scrubber, with the balance of $1,166,098 being the annual operating cost associated with maintaining this scrubber. The annual cost of one FCCU regenerative scrubber with a flow rate of 275,000 dscfm is $12,818,246. Of this amount,

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[3] Gonzales, Dan, Timothy Gulden, Aaron Strong and William Hoyle. Cost–Benefit Analysis of Proposed California Oil and Gas Refinery Regulations. Santa Monica, CA: RAND Corporation, 2016.

$10,999,872 is the cost of the equipment, and $1,818,374 is the annual operating cost.[4]

Of the five large refineries in the Bay Area, three could adopt scrubbers, with each implementing one, i.e. either a non-regenerative scrubber or a regenerative scrubber. It is important to note that these three refineries could choose to adopt scrubbers to ensure compliance with Rule 12-16 because they operate FCCUs that are significant sources of NOx, SO_2 and PM, which are addressed by the rule. Furthermore, one refinery and three non-refineries subject to the rule do not need to consider installing scrubbers as they do not operate FCCUs. Another refinery already operates an FCCU wet scrubber.

In Table 5 below we estimate the annual cost of compliance associated with Rule 12-16, should affected sources achieve the aims of the rule by adopting new equipment to stay below the emission cap. If the three refineries in need of implementing a scrubber did so, they would face a combined annual cost ranging from $19.0 million to $38.4 million.

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[4] Price Quote, Ed Hutter, DuPont Sustainable Solutions - Clean Technologies, Belco Technologies Corporation, October 28, 2014, 14-126-B-EDV.

Table 5: Aggregate Annual Capital and Operating Cost By Affected Industry: Low Scenario and High Scenario

Industry	NAICS	Nos. of Pieces of Equipment	Low Scenario (Non-Regenerative Scrubber)	High Scenario (Regenerative Scrubber)
Refineries	324111	3	$19.0M	$38.5M
Others				
Industrial Gas Manufacturing	325120	N/A	N/A	N/A
Other Electric Power	221118	N/A	N/A	N/A

Profile of Affected Sources

The three affected refineries (NAICS 324111) generate an estimated $26.6 billion in combined annual revenues and $1.0 billion in net profits. The two industrial gas manufacturers (NAICS 325120) generate anywhere between $200 million and $500 million in combined revenues, and between $15 million and $25 million in annual profits. Martinez CoGen (NAICS 221118) generates between $5 million and $15 million in annual revenues, and $225,000 to $500,000 in net profits.

Table 6: Economic Profile of Sources Affected By Rule 12-16

Industry	NAICS	Facilities	Est. Annual Revenues	Est. Annual Net Profits
Refineries	324111	3	$26.6B	$1.0B
Others				
Industrial Gas Manufacturing	325120	2	$200M - $500M	$15M - $25M
Other Electric Power	221118	1	$5M - $15M	$225K - $500K

Note: B = Billion, K = Thousand, and M = Million.

Source: Applied Development Economics, based on InfoUSA, California Energy Commission, the US Energy Information Administration, US Internal Revenue Service, and the Economic Census

Socioeconomic Impact Analysis of Rule 12-16

In both the low or high cost scenarios, the three affected refineries are not significantly impacted by Rule 12-16, should they choose to achieve the emissions-limitation aims of the measure by installing new scrubbers.

Table 7: Socioeconomic Impact of Rule 12-16 on Affected Industries

Industry	**NAICS**	**Establishments**	**Low Scenario**: FCCU Non-Regenerative Scrubber Cost Effectiveness	**High Scenario**: FCCU Regenerative Scrubber Cost Effectiveness	**Low Scenario**: FCCU Non-Regenerative Scrubber Cost Effectiveness: Cost to Net Profit	**High Scenario**: FCCU Regenerative Scrubber Cost Effectiveness: Cost to Net Profit
Refineries	324111	3	$19.0M	$38.5M	1.8%	3.6%
Others						
Industrial Gas Manufacturing	325120	2	N/A	N/A	N/A	N/A
Other Electric Power	221118	1	N/A	N/A	N/A	N/A

Source: Applied Development Economics

Small Business Disproportionate Impacts

According to the State of California, among other things, small businesses generate annual sales of less than $10 million.[5] Of the three sources affected by Rule 12-16, none are small businesses. Thus, small businesses would not be disproportionately impacted by Rule 12-16.

Scenario Two: Limiting Refinery Production

In this second part of the socioeconomic analysis, staff presents possible impacts resulting from a limit on production at refineries. Air District staff analyzed a variety of data sources on refinery capacity and utilization, and observed that emissions limits contemplated in Rule 12-16 do not appear to inhibit refining capacity as a whole, as the caps in the rule appear to be consistent with the current maximum production capability of area refineries.

It is not expected that the emissions caps in Rule 12-16 would have significant impacts on the market for refined fuels so long as fuel consumption does not significantly increase or statewide refining capacity does not significantly decrease. Consumption for fuel can increase in absolute and relative terms for a variety of reasons, with a corresponding increase in price of fuel at the retail level. For example, population growth and an increase in the number of persons commuting into the area would result in greater demand for fuel whose supply could be limited by Rule 12-16, resulting in a bidding-up of the price of fuel.

While the impact of a limited supply of refined product relative to demand on the retail price of fuel is observable in that prices tend to go up, how much prices increase can vary widely. Price spikes tend to be an inherent, if latent, feature of the oil refining-gasoline consuming activity, due to the combined facts that people tend to keep buying gas to drive their cars to work and other places even as the price of gas rises, and that California refineries tend to operate very close to capacity, meaning that refineries are unable to boost supply significantly when demand increases. As Borenstein notes, “The market

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[5] http://www.leginfo.ca.gov/cgi-bin/displaycode?section=gov&group=14001-15000&file=14835-14843

can easily become out of balance if there is an unexpected jump in demand, or more commonly, if a refinery experiences a supply disruption or outage and output is reduced."[6] Thus, in the case of the temporary shut-down of the southern Californian refinery in Torrance in 2015, California Energy Commission report that found that the 10 percent reduction in supply led to 27.6 cents increase in the cost of gasoline.[7] Local price increases can be more substantial. ADE, the Air District's socio-economic contractor, estimates that between February 12, 2015 and March 13, 2015 the average price of gasoline in the City of Los Angeles increased by 32 percent because of the Torrance shutdown, going from $2.65 a gallon to $3.51 a gallon.[8] The peculiarities of the California market also explain the magnitude of price increases in California when supply shocks occur. By way of example, Phoenix, Arizona in 2003 experienced a 30 percent drop in fuel volume resulting from a pipeline failure, which then led to a 37 percent increase in price of gas in Phoenix.[9] The FTC observed that prices in Phoenix in 2003 did not rise even faster largely because West Coast refineries were able to ship more gasoline into Arizona to hold down prices. The unique blend required in California makes it difficult (but not impossible) to ameliorate the effects of supply shocks along the lines of Phoenix in 2003, which perhaps explains why in one instance a ten percent drop in supply in southern California leads to almost 32 percent increase in price while a steeper 30 percent supply drop in Phoenix led to 37 percent price increase there.[10]

While the Torrance and the Phoenix examples demonstrate the potential for prices to rise when fuel supplies are decreased, projecting these variations following supply shocks is not an exact science. However, one could apply the Torrance and Phoenix examples to roughly estimate price impacts. Thus, if production at refineries is capped per the limits contemplated in Rule 12-16, then a percentage increase in population over a given time period would be equivalent to a reduction in supply of gasoline by a similar percentage over the same period. Since ABAG projects the nine-county San Francisco Bay Area region to grow by 9.2 percent over the ten-year 2015-2025 period, application of the Torrance example results in an estimated 29.4 percent increase in price over the same ten-year period.[11] This price increase would average less than three percent a year,

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[6] Borenstein, Bushnell, and Lewis, "Market Power in California's Gasoline Market" (May 2004), page 8

[7] Bay Area Air Quality Management District, Draft 12-16 and Draft 11-18 (Draft Staff Report: October 2016) page 23 (citing California Energy Commission)

[8] GasBuddy California http://archive.is/tlKBy

[9] Federal Trade Commission, Gasoline Price Changes: The Dynamic of Supply, Demand, and Competition (2005), page 29

[10] While it is true that California's market for refined product is almost a closed market due to the special blends generated only for Californians, there are some refiners outside of California who produce to California's standard, although delivery of their products takes 2 to 5 weeks and entails prohibitive transport costs. See Borenstein, Bushnell, and Lewis, "Market Power in California's Gasoline Market" (May 2004), page 20 ; see also US EIA, "California's gasoline imports increase 10-fold after major refinery outage" (October 2015) http://archive.is/oRGoI

[11] See http://archive.is/qGomH: The nine-county San Francisco Bay Area region is projected to grow over the ten-year 2015-2025 period by 672,600 persons, from 7,461,400 to 8,134,000. Including estimated number of non-residents commuting daily into the Bay Area for jobs, the total number of persons in the Bay Area will go from 7,938,800 in 2015 to 8,668,700 in 2025, for a 9.2 percent increase over the ten-year 2015-2025 period.

which would have a cumulative effect but would be much less than a short-term price shock such as occurred in the Torrance incident, or other price fluctuations that occur due to market conditions. For example, in January 2015, regular gasoline in California cost $2.68 per gallon, of which $1.29 was attributable to the price of crude oil purchased by the refinery. Six months later, a gallon of regular gas was $3.45, of which $1.45 was attributable to crude oil, for a 12 percent increase over a six-month period in the cost of a gallon of gas attributable to crude oil.[12] The overall price of gas in this six month-period increased by 29 percent, from $2.68 to $3.45 a gallon. In short, Rule 12-16 may introduce a regime to limit the production of refined petroleum products, but for various reasons, the price of these refined products can go up and down, consequently lessening the effect in modelling the socioeconomic impacts of a limit on the production of refined petroleum products supply on the wider economy.

VI. REGULATORY IMPACTS

Staff is concerned that a fixed numeric cap on refinery emissions may not be consistent with requirements of the Federal Clean Air Act (CAA) and the California Health and Safety Code (H&SC) where criteria pollutants are concerned. Both laws require the Air District to develop permitting programs that allow for criteria pollutant emissions to increase at a facility as long as those emissions are offset by an equal or greater amount of reductions of the same pollutant from a location within the region (CAA Sections 173(a) and 173(c)(1) and H&SC Sections 40918(a) and 40709(a)). The Air District has such a permitting program embodied in Regulation 2: Permits, Rule 2: New Source Review (Rule 2-2). This rule applies equally to all facilities in the Bay Area. Although state and local agencies may adopt more stringent rules than required by federal and state law, there is a significant argument that a fixed numeric cap for criteria pollutants conflicts with these federal and state provisions that allow facilities to increase emissions if certain conditions are met. It may be difficult to legally justify the necessity for such a measure, considering that jurisdictions with far worse air quality, such as the South Coast and San Joaquin air basins, have not adopted one.

Staff is also concerned that there is no support for imposing a specific regulatory approach on one sector of the regulated community without factual support for such selective treatment. Setting a fixed cap on PM, NO_X and SO_2 emissions for refineries as proposed by CBE would mean that these facilities would be required to offset any emission increases above the cap within their individual fence-lines. In addition, the proposed cap may prevent the construction and operation of new equipment already permitted by the Air District. That means a different set of permitting rules would apply to these refineries and support facilities than to other sources in the Bay Area. The rule would address pollutants of primarily regional concern by limiting those pollutants from one Bay Area industrial sector through a mechanism unique to that industry and unlike the mechanism for all other industrial sectors, which relies on standards for the equipment operated by the industry and measures compliance through scientifically-tested methods rather than

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[12] See http://bit.ly/2mkDgLW

inventory approximations. This would likely be viewed by a court as arbitrary and capricious. This is a problem for criteria pollutants, given that, as explained below, the Air District's current air quality monitoring data does not show that the concentrations of the criteria pollutants covered under the cap in Rule 12-16 are higher in refinery communities than in other urbanized areas of the region.

The Air District currently has multi-pollutant air monitoring stations located near refineries in San Pablo, Concord, Vallejo and San Rafael with multiple additional stations measuring sulfur compounds surrounding the refineries. The data from these monitoring stations show that air quality in refinery areas is comparable to other urbanized locations for $PM_{2.5}$, NO_x, and $SO_{2.}$ Air District maximum readings for $PM_{2.5}$ or NO_x do not come from the refinery-area monitors. In addition, data show that concentrations of SO_2 in refinery communities are well below the National and California Ambient Air Quality Standards. It is important to note that $PM_{2.5}$ from refineries is produced predominantly from combustion, resulting in the $PM_{2.5}$ being sent aloft, and therefore typically contributes to regional $PM_{2.5}$ as opposed to producing localized impacts such as those associated with wood smoke or diesel engines. It is possible that some combustion sources may have more localized impacts depending on stack height, weather and topography. Those types of sources are more effectively addressed through direct regulation than through a facility-wide cap which would allow for emissions to be shifted around the facility.

Figure 5 below compares measured concentrations of $PM_{2.5}$ in refinery-area monitors with concentrations measured elsewhere in the Air District. Note that San Jose consistently has the highest $PM_{2.5}$ concentrations in the Bay Area. Concentrations of this pollutant measured in the refinery areas are similar to measured concentrations in Livermore and San Francisco. All the monitors show concentrations lower than the National Ambient Air Quality Standard (NAAQS) for $PM_{2.5}$.

Figure 5: Ambient Measurements of PM$_{2.5}$

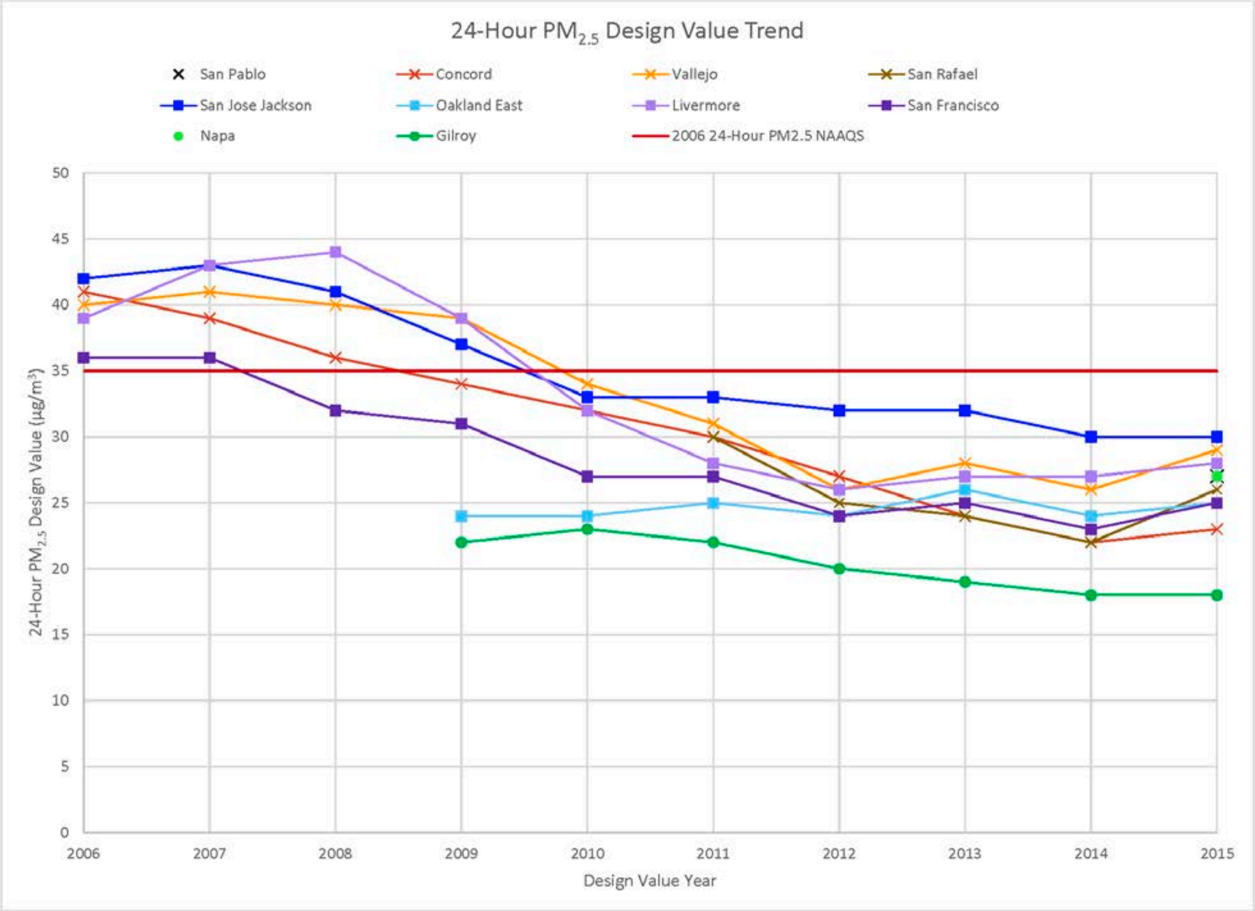

Figure 5: Ten years of 24-Hour PM$_{2.5}$ design values at Bay Area monitoring stations. The design value for 24-hour PM$_{2.5}$ is the three-year average of the 98th percentile of daily values. The Design Value Year is the last year of the three-year average. Source: US EPA's Air Quality Systems (AQS) database (October 7, 2016).

The Air District's evaluation of risk from toxic air contaminants indicates that most of the toxic risk from refineries is from benzene from leaks and particulate matter from diesel-fired engines (diesel PM). The proposed cap would have no effect on the risk from these toxic air contaminants. This is why Air District staff is developing Rule 11-18, which will reduce the risk from air pollution in refinery communities and across the Bay Area in a manner that directly requires actions to reduce health risk from air pollution.

In conclusion, Air District staff believes CBE's proposed concept for Rule 12-16 would likely be found by a Court to be beyond the Air District's authority and/or arbitrary and capricious, where criteria pollutants are concerned. Staff's analysis also indicates that the proposed rule is unlikely to improve air quality in refinery communities since it does not reduce emissions.

VII. THE RULE DEVELOPMENT / PUBLIC PARTICIPATION PROCESS

The publication of this document is intended to support the initial public comment portion of the development of these two rules. Key milestones dates for the rest of the process are as follows:

November 9, 2016	Open House in Richmond
November 10, 2016	Open House in Oakland
November 14, 2016	Open House/Scoping Meeting in San Francisco
November 15, 2016	Open House in San Jose
November 16, 2016	Open House/Scoping Meeting in Martinez
November 17, 2016	Open House in Fremont
December 2, 2016	Comment deadline for draft rules and NOP/IS
March 24, 2017	Final rules, staff report, draft EIR published for comment
March 27, 2017	Workshop in Cupertino
March 28, 2017	Workshop in Benicia
March 29, 2017	Workshop in Hayward
March 30, 2017	Workshop in Richmond
May 8, 2017	Comment deadline for final rules
May 25, 2017	Board Package, including Final Staff Report, Responses to Comments, and final rule language published
May 31, 2017	Public Hearing - Board consideration of final rules

IV. CONCLUSION

Pursuant to the California Health and Safety Code Section 40727, before adopting, amending, or repealing a rule the Board of Directors must make findings of necessity, authority, clarity, consistency, non-duplication and reference. The Air District staff believes the GHG portion of the proposal meets the requirements of this statue for the reasons listed below.

Necessity Finding

The proposal is necessary because neither top-down nor market-based approaches to climate protection have proven effective in sufficiently reducing climate pollutants[13] and there are no finalized plans to impose a carbon tax nor direct regulation of industrial sources of GHGs. Because there has been two decades of efforts without significant demonstrable progress on the state, federal or international levels, it is imperative / necessary for local governing agencies such as the Air District with the political will to do as much as legally possible to regulate GHG emissions. Because of this imperative, the Air District is compelled to act within its authority to limit and reduce GHG emissions from refineries and other significant sources to achieve short-term, interim, and long-term GHG reduction goals until such efforts are no longer necessary.

- International Treaties: Little to no progress has been made since the ratification of the 1997 Kyoto Protocol was adopted in Kyoto, Japan, on and became effective in 2005. Although the United States was a signatory to the Protocol, it has never been ratified. While, the U.S. also entered into the Paris Agreement, it appears unlikely that the current Administration will honor the commitment to the accord.

- Market-Based Approach: The State's Cap-and-Trade approach to reducing GHGs from various industrial sectors have yet to produce significant reductions from the refineries in the Bay Area. Changes in GHG emissions from the petroleum refining industrial sector have not been the result of regulation—but primarily due to economic and market forces, relating more to the state of the economy, with decreases since the passing of AB 32 related to the downturn in the economy and more currently, trending to increase as the economy improves.

- No Direct State Regulation of Refinery GHG Emissions: Since the passing of AB 32, in 2006, CARB has not adopted any regulation that directly limits or reduces the GHG emissions from refineries. Up to this point, the State has solely relied on market forces via Cap-and-Trade to address GHG emissions from this sector. It is imperative to ensure that GHG emissions are limited as soon as possible to curtail increases in GHG emissions from major sources such as refineries in our efforts to control the contributing pollutants to anthropogenic climate change.

- Global Pollutant, Locally Emitted: While it is accepted that GHGs collectively have a global impact, these pollutants are emitted locally from various sources, including mobile / fuel, stationary source / industrial, energy, agricultural, water, waste management, and natural lands sectors. Historically, the stationary sources are controlled most effectively at the local level by the agencies most familiar with them, that have a long history regulating their emissions – the local air districts.

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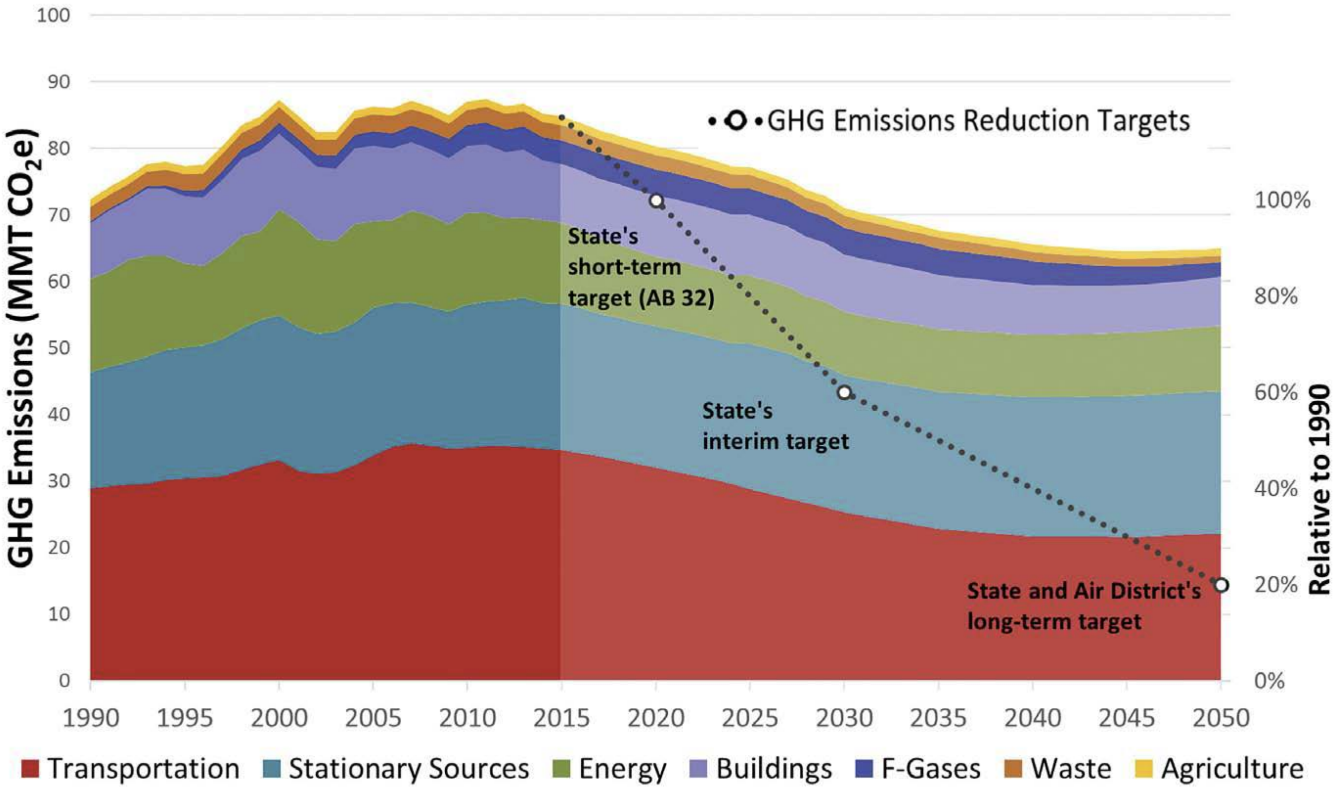
[13] Air District GHG emissions projection indicate that stationary source GHG emissions will not achieve the short term 2020 goal of 1990 emissions.

- Necessary First Step to Limiting GHG Emissions: Limiting GHG emissions from refineries is a needed first step to ensure that as demand for transportation grows and crude and product slates change, GHG emissions from this significant source does not erase any progress made in the last few years while CARB and the Air District look for additional ways to limit or reduce GHG emissions.

- State and Air District Interim and Long-term GHG Reduction Targets: In 2013 the Air District adopted a long-term GHG emissions reduction goal of 80 percent of 1990 levels by 2050. Recently, in the 2017 Clean Air Plan, the Air District adopted the interim GHG reduction goal of 40 percent reduction by 2030. These goals are consistent with the State's interim and long-term GHG reduction goals. AB 32 also established a short-term goal of reducing the State's GHG emissions to 1990 levels by 2020. Figure 3-9 from the Air District Clean Air Plan shows that we are NOT on-track to meet the 2020 goal, and dramatic reductions are needed in less than 13 years to achieve the 2030 goal.

Air District Clean Air Plan: Figure 3-9. **Projected Bay Area GHG Emissions by Sector Based on State Policies, (100-year GWP)**



- To achieve these goals, major sources of GHG emissions in the Air District would have to make significant reductions in their GHG emissions. Air District emissions inventory indicates that refineries were responsible for 68 percent of the stationary source GHG emissions in 2015. The following table illustrates the annual emissions and percent emission reduction needed if refineries were to proportionate reduce their GHG emissions to meet the short-term, interim and long-term goals.

Refinery GHG Emissions Projections Based on State and Air District GHG Goals

Calendar Year	**State and/or Air District GHG Reduction Goals** (relative to 1990)	**Refinery GHG Emissions** (MMT CO_2e)	**% Reduction of 2015 GHG Emissions needed**	**% Reduction needed each year**
2015	n/a	14.5	n/a	n/a
2020	100%	11.6	20%	5%
2030	40% Below	7.2	50%	3%
2050	80% Below	2.2	85%	1.75%

The Air District's best estimated projections show that the Air Basin would not achieve its goals for 2020, 2030, nor 2050 even considering state policies and regulations already adopted, as well as those that are likely to be adopted and implemented over the next ten to 15 years.[14] To successfully implement many of the state policies and regulations, the State will need cooperation and assistance from the regional and local agencies.[15]

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[14] Potential emission reductions from additional stat actions that may be included in the 2017 Scoping Plan update are not reflected in this analysis.

[15] Bay Area Air Quality Management District, 2017 Clean Air Plan, p. 3-19.

Responses to Comments on Rule 12-16

Comments from Individuals

Individual Comments of Support for Rule 12-16:

Twenty-three (23) individuals from many locations in the Bay Area wrote to support adoption of Rule 12-16. Some of the reasons for support include: fighting climate change, prevention of large increases in refining of Canadian "tar sands" crude oil, does not unduly limit refinery operations since the cap is set higher than current emissions, would avoid increases in health impacts on the community associated with processing "dirtier" crude sources, the Bay Area is tied for 6th place worst particulate matter pollution – according to the American Lung Association, Californians should lead by example in addressing carbon emissions, refinery emissions are a health burden in communities of color, need to establish overall emissions caps on refineries.
Some of these comments in support of Rule 12-16 also expressed concern that the staff opposed the Rule.

One individual commented in support of greater control on refinery emissions, but opposed Rule 12-16 as being too lenient.

Staff Response:
Staff shares the concerns expressed in these emails. However, as explained in the Staff Report, there are concerns about the legal defensibility and unintended impacts of Rule 12-16, as currently drafted in accordance with the policy vision developed by CBE and their associates. Staff believes that there are better, more defensible and more effective methods to accomplish the goals of Rule 12-16 and address the concerns detailed in these emails.

Increasing PM and GHGs Trends

Comment: According to the Air District's own data and in contrast to some other pollutant emissions, both particulate matter emissions and greenhouse gasses from Bay Area refineries have increased significantly over the past several decades, in contrast to some other pollutants.

C. Davidson

Staff Response:
Air District staff does agree with this comment. There is no evidence that refinery GHG and PM emissions are increasing.

Loopholes in Rule 13-1

Comment: Rule 13-1's first potential GHG loophole regards the highly variable diluting of very heavy oils with much lighter solvent oils to obtain a much lighter, more liquid and more "workable refinery blend" which would still require very high-GHG processing, but remain just below the per barrel limit. The case-in-point regards refineries developing new capacity to refine bitumen as feedstock, which is an extremely high-sulfur, semi-solid non-conventional oil. So by dilution, a refinery could still process large amounts bitumen and yet, remain under almost any per barrel GHG limit.

C. Davidson

<u>*Staff Response:*</u>
The commenter has provided no information that would support the claim the refineries would opt to blend heavy oils with much lighter solvent oils and that the resulting product, diluted bitumen (DilBit) would always meet the carbon intensity limits contained in Rule 13-1 and result in greater emissions of various pollutants.

<u>Comment:</u> The second GHG loophole for Rule 13-1 is to first separate the heaviest oil fractions out of DilBit, by distillation at one facility and then further process this semi-refined, heaviest fraction of bitumen at a second facility. In fact, from anywhere in the world, partially refined or pre-processed extra heavy bottom oils, from tar sands or otherwise, could be diluted significantly to below any per barrel limit and then delivered by ship to any local area refinery.

C. Davidson

<u>*Staff Response:*</u> *The scenario outline in this comment could also act as a basis to ensure compliance with Rule 12-16 in its current form. Refiners could preprocess crude at refineries outside of the Air District to be finished at a Bay Area refinery, thus reducing the refineries' over all GHG emissions and, therefore, ensure compliance with the GHG emissions of 12-16 through displacement of the GHG emissions associated with the initial steps of crude refinement.*

<u>Comment:</u> The third major GHG loophole in Rule 13-1 regards the questionable status quo of having, as undisclosed and proprietary, major chemical constituents of crude feedstocks that markedly distinguish the various quality types of crude oils that create the varieties of processing required and the levels of emissions produced. In the case of DilBit, the asphalt content is both the primary constituent fraction of bitumen and the primary cause of bitumen being the most GHG-intensive to refine into gasoline.

C. Davidson

<u>*Staff Response:*</u> *As currently drafted, Rule 13-1 is agnostic regarding the characteristic of the crude oils processed. While the quality of the crude would may impact refinery emissions, for determining compliance, the rule would rely on the volume of crude or other input relative to the amount of GHGs emitting from the refinery and other associated processes.*

<u>Comment:</u> Air District's fourth stationary source GHG loophole now exists. Not directly related to Rule 13-1, but to Rule 12-16, the fourth loophole to refinery-wide GHG limits is Air District's recently proposed Draft 2017 Clean Air Plan. The Plan includes a Stationary Source Control Measure SS 12, which would establish Petroleum Refining Climate Impacts Limit, ostensibly, to limit facility-wide carbon intensity. According to the plan, if carbon intensity "limits" were exceeded, a scheme is provided to "offset" the increase in carbon intensity through the "Low Carbon Fuel Standard (LCFS) framework." Since the LCFS framework includes credits for biofuels production, the offset would allow increased biofuel production to offset increased carbon intensity from processing tar sands.

C. Davidson

Staff Response: That measure has been update in the Clean Air Plan. The current draft of Rule 13-1 does not allow for the purchases of offsets through the LCFS framework.

Rule 12-16 Is a No-Cost Proposal

Comment: Finally, I am curious why BAAQMD District Counsel Brian Bunger would have articulated strongly, in the recent past, that Rule 12-16, the refinery-wide emissions limit is "arbitrary and capricious", but not Rule 13-1, the per barrel limit? Yet, just this week, CARB's executive director has affirmatively clarified the legality of Rule 12-16 and 13-1 by stating clearly:

> "With regard to the District's draft Regulation 12, Rule 16, limiting emissions increases from refineries, and the new concept of Regulation 13, Rule 1, establishing a carbon intensity cap for refineries [C.D.: i.e., a per barrel CO2/GHG emissions cap], we agree that both the approaches could help to ensure that these sources do not add to the state's overall emissions of greenhouse gasses and criteria or toxic pollutants." (5)

I am not opposed to Rule 13-1, the per barrel emissions limit, but believe that Rule 12-16's refinery-wide GHG and criteria emissions limits 1) need not hamper profitable refinery operations; 2) nor produce jobs loss; 3) nor require each refinery to reverse long-standing proprietary policies on crude chemistry information. Importantly, Rule 12-16 greatly needs rapid adoption after four years and it should ultimately make for safer refineries and communities.

C. Davidson

Staff Response: Staff disagrees that Rule 12-16 offers a no-cost option for limiting GHG emissions. It is reasonable to assume that at some point a refinery's emissions may be on the verge of exceeding or exceed its emission limits for any one of the pollutants addressed by Rule 12-16; if this potentiality were not the case, there would be no need for Rule 12-16. In evaluating this potential, staff determined that there were three scenarios under which adverse environmental impact could occur—the installation a selective catalytic reduction (SCR) unit to control NOx emissions and the installation and operation of a wet gas scrubber to control SO2 emissions. The socioeconomic impact analysis (summarized in the Staff Report) found that compliance with Rule 12-16 by installing a wet gas scrubber could cost as much as $10,999,872 for the equipment, and $1,818,374 in annual operating cost.

Individual Comments in Opposition to Rule 12-16:

CJN

I believe in smart, scientifically-based regulation that provides real emissions reductions. I fear that these rules are being rushed through the rule making process without proper thoughtfulness and consideration leaving many environmentalists, community members, and industry workers confused about the real value to Bay Area citizens.

Staff Response: Rule 12-16 has been in development for more than 1 year, with adequate time for input and comment from all affected parties.

12-16 is narrow-sighted and fails to consider the larger issues of greenhouse gas pollution such as leakage and consumer energy needs.

Staff Response: Rule 12-16 provides +7% increase in emissions from each refinery's highest annual emissions during the baseline period from 2010 – 2015, and is likely adequate to supply the Bay Area's current transportation fuel needs. Future needs are uncertain, as population growth is anticipated to be offset by increased use of mass transit, improved fuel economy, and more alternate fuel vehicles. Projections by the Energy Information Administration indicate total transportation fuels are expected to peak at approximately 7% above the baseline period in 2018, at a level 4% less than the peak fuel demand in 2007.

Refineries are already subject to permit limits, caps, emissions limits, and emissions concentration limits.

Staff Response: The Air District agrees that source permit limits and emissions limits are very effective. However, some refinery process units are "grandfathered" and do not have specific permit limits. Changes in operation could lead to higher emissions from those specific grandfathered units.

K M -

Why is the BAAQMD trying to make this regulation law when it is clear that the District believes it will not have an impact on air quality in the Bay Area?

Staff Response: Rule 12-16 is intended to prevent future increases in air emissions, rather than reduce existing air emissions.

Do the Refinery 2010-2014 baselines (table 12-16-301 and 302) take into account the Refineries not operating at full capacity during certain years (i.e. because of equipment failure, large turnarounds, etc.), and if not, can you propose a new baseline that would include this analysis?

Staff Response: Rule 12-16 proposes using the highest annual emissions during the baseline period of 2010 – 2015, plus 7% as the limit for each criteria pollutant and for GHG emissions.

P V -

This commenter wrote to oppose any regulation of CO_2, expressing concern about impacts on gasoline prices. He also expressed concern about the rule increasing net GHG emissions due to production constraints in the Bay Area leading to production elsewhere and shipping emissions. He asked the Air District to focus on more traditional pollutants.

Staff Response: CO_2 is an air pollutant whose impacts are felt globally. Controls are needed everywhere to prevent severe impacts from climate change. The Air District has set aggressive goals to reduce local GHG pollution and some local rulemaking will be required to meet those goals.

Comments from Organizations

California Air Resources Board

Regarding 12-16 and 13-1, we agree that both approaches could help ensure no increases of pollutants. We recommend establishing an industrial source action committee within the California Air Pollution Control Officers' Association, with an initial focus on refineries.

Staff Response: The Air District looks forward to working with CARB through an industrial source action committee of CAPCOA.

Citizens Against Pollution, Peninsula Interfaith Climate Action

These groups commented in support of Rule 12-16 for reasons like those expressed by individuals supporting the rule.

Staff Response: As mentioned above, staff shares the commenters' concerns about the impact of air pollution from refineries. However, we are concerned about the legal defensibility and effectiveness of the policy recommended by CBE and their associates.

National Resources Defense Council

In its staff report for Regulation 12, Rule 16 BAAQMD focuses on two potential mechanisms for reducing greenhouse gas (GHG) and criteria emissions: (1) installation of wet gas scrubbers in facilities operating fluidized catalytic cracking units (FCCU); and (2) limiting refinery production. These are not the only mechanisms available to limit refinery emissions and to fully inform the public, BAAQMD's discussion and evaluation of Regulation 12, Rule 16 should reflect the full range of emissions reductions mechanisms available.

There are a number of options for reducing refinery GHG and criteria emissions, which include shifting to sweeter and cleaner crude feedstocks and curtailing production. However, refineries can also undertake energy efficiency improvements or equipment upgrades, independent of wet gas scrubbers, which have the potential to greatly reduce refinery emissions and would not require cuts in refinery production.

Staff Response: The staff's socioeconomic and CEQA analysis focused on these two potential responses to the limits in Rule 12-16 because these responses are the most environmentally and economically impactful mechanisms that the refineries might employ to address the rule.

NRDC has also analyzed various studies showing that energy efficiency measures can reduce refinery carbon dioxide emissions in a cost-effective manner. According to McKinsey and Co., the refining industry could reduce energy use 13% by 2020 through commercially available technologies, and at an internal rate of return of at least 10%. Energetics Incorporated found that technical potential was as high as 26%, if best practices and state-of-the-art technologies are used.

Staff Response: Each refinery submitted a list of refinery-specific energy improvement projects to the California Air Resources Board in response to the California Regulation for Energy Efficiency and Co-Benefits Assessment of Large Industrial Facilities in late 2011. Review of those range of energy improvement projects finds that projects with simple payback within 10 years results in emissions benefits for particular refineries of 0.02% to 4.02% if all projects are implemented and achieve the expected results. The emission reduction potential shown in the NRDC's more general studies may not be achievable at the specific refineries in the Bay Area.

United Steelworkers (USW)
United Steelworkers (USW) District 12 is writing you to offer updated comments on Draft Regulation 12-16, which are currently under consideration by the Bay Area Air Quality Management District (BAAQMD). While we strongly support action to reduce greenhouse gases (GHGs) and emissions of criteria pollutants and toxic air contaminants (TACs) that can harm workers and communities, we continue to have unanswered questions about rule 12-16. We therefore respectively urge the board to postpone a decision on this draft rule – beyond the current May 31 meeting date – until our concerns are adequately addressed.

Our fundamental questions concern a) whether local emission caps on GHGs at refineries will have the intended impact of reducing emissions of GHGs overall; b) whether those same caps are an effective method for reducing the emissions of criteria pollutants and TACs, which are a primary cause of negative health impacts on public and worker health; and c) whether the rule will cause refiners to rely more heavily on imported fuels, if they are prohibited from growing their business in California – resulting in a larger GHG footprint for California's fuels; higher fuel prices that will be felt most directly by lower income residents; reduced ability of the California fuel supply to respond quickly in the event of a refinery failure or upset; and job loss at refineries and all the local businesses that are part of the same economic ecosystem.

Staff Response:

a) *The economic impacts of the rule are uncertain and depend on whether the consumption of transportation fuels declines, as predicted by the California Air Resources Board (CARB), or increases as it has been doing since 2012.*
b) *GHG emissions are correlated to criteria pollutant and TAC emissions, validated by Tracking and Evaluation of Benefits and Impacts of Greenhouse Gas Limits in Disadvantaged Communities: Initial Report from CalEPA Office of Health Hazards Assessment, February 2017*
c) *Rule 12-16 proposes using the highest annual emissions during the baseline period of 2010 – 2015, plus 7% as the limit for each criteria pollutant and for GHG emissions. These limits should provide adequate capacity to supply current transportation fuels needed in the Bay Area.*

Until we can predict with some measure of certainty that rule 12-16 will not increase the import of fuels with a greater carbon footprint and thus send us in the wrong direction on GHG reduction, and until we can say with certainty that it will significantly improve the health of local residents in refinery communities, we urge the board to table this rulemaking.

We are continuing to analyze Rule 12-16; however, in light of what we have learned thus far, we are urging the Board to postpone its decision, now slated for May 31, based on the following unanswered questions:

1) What will be the impact on worker and community health?
The Rule does not address criteria pollutants or TACs, which are important for both worker and community health. For refineries, these include diesel particulate matter from diesel-fired equipment, benzene from process leaks, 1,3-butadiene and others. We believe an emissions rule should include both criteria pollutants and TACs, in addition to GHGs.

Staff Response: It is correct that Rule 12-16 does not include Toxic Air Contaminants (TACs). The staff believes that these contaminants are best addressed in a risk-based rule and we are developing Rule 11-18 for that purpose. That rule will cap toxic risk from refineries and other sources all over the Bay Area.

2) Is there evidence of co-benefits at the specific refineries covered by the proposed rule?
It is not clear to us that, in this case, that placing caps on GHGs would have the co-benefit of also reducing criteria pollutants and TACs. The pollution control technologies to capture particulate matter, for example, differ from those that are designed to capture volatile organic compounds (VOCs), such as 1,3-butadiene and others. It is also not clear to us that BAAQMD could regulate emissions based on the theory that doing so would provide indirect co-benefits to health.

Furthermore, the BAAQMD's own October 2016 staff report (page 20) raised significant questions about the efficacy of co-benefits when applied to specific Bay Area refineries.

Staff Response: As state in the staff reports, rules need to be justified for their own results, rather than for co-benefits. That said, GHG emissions are correlated to criteria pollutant and TAC emissions, validated by Tracking and Evaluation of Benefits and Impacts of Greenhouse Gas Limits in Disadvantaged Communities: Initial Report from CalEPA Office of Health Hazards Assessment, February 2017, and by A PRELIMINARY ENVIRONMENTAL EQUITY ASSESSMENT OF CALIFORNIA'S CAP-AND-TRADE PROGRAM. However, since many of these correlated pollutants are emitted from tall, hot stacks, the pollution usually lofts over the nearby community and contributes to regional, rather than localized pollution. A risk-based analysis is a better way to protect local communities.

3) Will capping GHGs at refineries align with the state's cap-and-trade program?
It is not clear to us how capping GHGs from individual sources can be consistent with both the theory and operation of the state's cap-and-trade policies under Health and Safety Code §40727. Shouldn't this also be resolved before proceeding with this Rule? We recognize that the California Air Resources Board recently weighed in with a suggestion that CARB and BAAQMD work together to ensure Rule 12-16, Rule 13-01 and CARB regulations are complementary. CARB suggested establishing an "industrial source action committee" within the California Air Pollution Control Officers' Association. We support this proposed structure so that the BAAQMD and ARB can together and take the necessary time to figure out how various approaches might work – or not work – together and alone. As noted above, the USW will gladly participate in such a committee.

Staff Response: CARB has commented that Rule 12-16 (and 13-1) could help ensure no increases of pollutants. The Air District looks forward to working with CARB through an industrial source action committee of CAPCOA.

4) Would the cap proposed under Rule 12-16 conflict with the occasional need for refineries to increase capacity due to a failure in the system?
This is a unique requirement in California because the state is isolated by time and distance from other sources of transportation fuels and is therefore nearly self-sufficient in fuel production. Imports make up only between three and six percent of total statewide supply for the 15 billion gallons of gasoline consumed each year. Total statewide gasoline demand rose 3.9 percent between 2013-2015.

California is able to shift production capacity internally when needed. Following the February 2015 Exxon Mobil explosion, which took that refinery off line, Bay Area refineries went from supplying about 45 percent of the state's gasoline to supplying about 60 percent, an increase of 33 percent. This required an increase in output from two million barrels per week to about 3.2 million barrels per week. The capacity of the Bay Area's refineries to expand was an important factor in mitigating the negative economic impact of the Exxon incident, which a 2015 RAND analysis concluded caused a $6.9 billion contraction in the state's economy.

Would Rule 12-16 trigger a violation if a refinery increased their output in response to a supply failure?

Staff Response: Rule 12-16 proposes using the highest annual emissions during the baseline period of 2010 – 2015, plus 7% as the limit for each criteria pollutant and for GHG emissions. These limits should provide adequate capacity to supply current transportation fuels needed in the Bay Area. An extended unplanned emergency refinery shutdown is quite rare. A situation such as the 2015 Exxon Mobil incident that drastically affects statewide supply is best handled through the variance process or, if a variance cannot be obtained, through enforcement discretion as appropriate. Structuring the 12-16 emissions cap to accommodate production in emergency situations would undermine the purpose of the rule.

5) Will Rule 12-16 result in GHG "leakage" and higher gasoline prices?
In the wake of the Exxon explosion, imported gasoline from foreign sources rose from meeting about three percent of total statewide demand to about eight percent of demand, or from about 140,000 barrel per week to 420,000 barrels per day. This represented an increase of 42 percent in total imported gasoline statewide.

In light of the 3.9 percent growth in statewide gasoline demand between 2013-15, as well as the potential for system failures, could Rule 12-16 lead to an increase in imported gasoline, both continuously and episodically, as refineries find it impossible to increase production?

Would this imported gasoline come with a larger GHG footprint for refining and transportation, thereby defeating the purpose of Rule 12-16 to reduce GHGs? Would the higher costs associated with importing gasoline into California be passed along to the public, where it would be felt most immediately among lower income residents?

We believe the possibility of "GHG leakage," whereby carbon and other GHGs are simply moved from one regulated location (in this case the Bay Area) to a less regulated location, should be investigated as a potential unintended consequence of this rule before it is subject to further actions by the Board.

Staff Response: The economic impacts of the rule are uncertain and depend on whether the consumption of transportation fuels declines, as predicted by the California Air Resources Board (CARB), or increases as it has been doing since 2012. Rule 12-16 provides +7% increase in emissions and production capacity from each refinery's highest annual emissions during the baseline period from 2010 – 2015, and is adequate to supply the Bay Area's current transportation fuel needs. Future needs are uncertain, as population growth is anticipated to be offset by increased use of mass transit, improved fuel economy, and more alternate fuel vehicles. Projections by the Energy Information Administration indicate total transportation fuels are expected to peak at approximately 7% above the baseline period in 2018, at a level 4% less than the peak fuel demand in 2007.

Moreover, we recognize that 12-16 could impede the ability of any of the state's refineries to expand, even if the expansion would be necessary to produce transportation fuels with lower carbon intensity. To meet its GHG objectives by 2020, California must be able to take every step to reduce the carbon intensity of transportation fuels, since this sector is by far the largest emitter of GHGs each year. If a refinery expansion could meet the state's need for lower-carbon fuels, why would the District implement rules that would prohibit such an expansion?

Staff Response: Refinery expansion and modifications may continue to occur through Regulation 2, Rule 2: New Source Review. However, any increase in air emissions must be off-set within the refinery. This represents a significant deviation from the current new source review requirements.

Western States Petroleum Association (WSPA)
Attachment A: WSPA Legal Comments on Proposed Rule 12-16

As the District is aware, WSPA submitted comments on the District's Project Description for Rule 12-16 on September 9, 2016, and on the District's Proposed Draft Rule 12-16 on December 2, 2016. WSPA continues to have significant concerns with the conceptual goal of Rule 12-16 and with the practical implementation of the rule's provisions. In general, WSPA agrees with District Staff's assessment that Rule 12-16 would not withstand judicial scrutiny. Proposed Rule 12-16 is inconsistent with existing federal and state air programs, would not be in harmony with the state cap and trade program for greenhouse gas emissions, arbitrarily limits specific refinery emissions to levels that are not necessary to protect local communities, and is beyond the District's statutory authority.

Staff Response: Air District staff does not recommend Rule 12-16 in its current form because of the legal concerns expressed in the staff report.

WSPA has submitted multiple letters and sets of comments to the District discussing its concerns over the legality of imposing numeric caps on emissions of GHGs, PM_{10}, $PM_{2.5}$, NO_X, and SO_2

from petroleum refineries. WSPA summarizes its concerns here, and incorporates by reference its past comment letters on Rule 12-16.1

The Board Cannot Adopt Rule 12-16 Without Making the Six Statutory Findings Required under the California Health and Safety Code

Prior to adopting a new or amended rule, the District must make six statutory findings: necessity; authority; clarity; consistency; non-duplication; and reference. Cal. Health & Safety Code § 40727. The Staff Report to Rule 12-16 was prepared "[a]t the direction of the Board … to provide an assessment of the rule's consistency with the Air District's statutory authority." Staff Report, at 5. The Staff Report fails to make these required findings; in fact, it cannot, because District Staff have concluded that adoption of Rule 12-16 would likely be beyond the Air District's authority and/or arbitrary and capricious. See Staff Report, at 39. Assuming that the Board is considering Rule 12-16 for adoption, the Board cannot adopt proposed Rule 12-16 without first demonstrating that the rule is within the District's authority, and providing an opportunity for public review and comment on that analysis. See id. § 40727.2(a) & (i).

Staff Response: Air District staff does not recommend Rule 12-16 in its current form because of the legal concerns expressed in the staff report.

Numeric Emissions Caps are Not Necessary

The numeric emissions caps under proposed Rule 12-16 are not necessary to protect public health or to address an existing air quality concern in the Bay Area. Emissions of GHGs, PM_{10}, $PM_{2.5}$, NO_X, and SO_2 are already extensively regulated at the federal, state, and local level. As the Staff Report explains, these rules apply standards "that ensure emissions are effectively controlled." Staff Report, at 13. Further, the broad range of air quality regulations that have been adopted by the District, California Air Resources Board (CARB), and the U.S. Environmental Protection Agency (EPA) were designed to ensure that emissions decrease over time and air quality improves. And indeed, existing ambient monitoring data and emissions inventories demonstrate just that: there have been consistent decreases in emissions and improvement in air quality in the Bay Area. See, e.g., Staff Report, at 14 ("mass emissions generally have been substantially reduced over the past several decades").

Proposed Rule 12-16 does not address any *current* emissions problem. Rather, it is rooted in the *possibility* that refinery emissions will increase in the future based on an assumption that changes in crude oil sources (from traditional sources to heavier sources requiring more intensive processing) will affect refinery emissions. See Staff Report, at 9-10 ("The intent of Rule 12-16 is to discourage or prevent refineries in the Bay Area from making changes that would lead to increases in emissions of certain pollutants"). WSPA and its members have repeatedly pointed out in prior comment letters that the possibility that new sources of crude oil will result in increased emissions is not supported by the facts, because, as the Staff Report briefly mentions, each refinery is designed to process a certain range of crude oil feedstocks, and its emissions from these operations are limited by the terms of its permit. See Staff Report, at 8-9. Any physical changes made to refinery operations to accommodate a different crude feedstock would already trigger permitting requirements and new emissions limits under the District's existing New Source Review (NSR) rules.2 Thus, increased emissions stemming from operational changes at a facility would already be within the District's permitting authority. The hypothesis that refinery emissions may increase in the future based on changes in crude slate therefore does not constitute a "need" for numeric emissions caps today, given the District's existing regulatory authority in this area.

Staff Response: To the extent the comment asserts that a rule intended to prevent future increases in emissions cannot be supported as "necessary" under H&S Code § 40727, the Air District disagrees. Supporting the necessity of such a rule entails establishing the likelihood of emission increases such that the increases are shown to be more than hypothetical. The Air District believes it has done so here by explaining that changes in crude can affect emissions. While existing permit limits are a significant constraint on the potential for emissions to increase due to changes in crude, they are not an absolute barrier. Grandfathered sources (i.e., sources that have not been through New Source Review and therefore do not have limits on usage) are one reason why.

Furthermore, the Board cannot legally adopt Rule 12-16 without supporting the need for selectively targeting petroleum refineries. WSPA agrees with the assessment in the Staff Report that the imposition of numeric emissions caps on petroleum refineries would effectively create "a different set of permitting rules" for refineries than other sources in the Bay Area "by limiting pollutants from one Bay Area industrial sector through a mechanism unique to that industry and [that is] unlike the mechanism for all other industrial sectors." Staff Report, at 37. Imposing a different regulatory scheme on refineries is not currently justified in either law or air quality science.

Staff Response: Air District staff does not recommend Rule 12-16 in its current form because of the legal concerns expressed in the staff report.

Proposed Rule 12-16 Would Conflict with Existing Local, State, and Federal Air Programs and Policies

Proposed Rule 12-16 is likely to restrict refinery emissions to levels that are lower than those authorized under the refineries' current operating permits. These permits were obtained in accordance with the District's existing regulatory program (the NSR program), following detailed technical analyses by the District of refinery operations and emissions data; by law, these permits incorporate emissions limits and control requirements that represent the most stringent of all existing regulatory requirements, within thresholds determined by District Staff to be protective of public health.

Proposed Rule 12-16 would establish a new emissions cap, not based on available technology or public health thresholds, but rather solely on historical emissions. This approach has no basis in science. Refineries have vested rights in operating consistent with the emissions levels in their legally obtained permits, and generally rely on being able to operate up to their permitted potential to emit if needed. Rule 12-16 would arbitrarily re-set those authorized limits, in direct conflict with the District's current permitting rules and policies, without any showing of necessity (as described above).

Staff Response: To the extent the comment asserts that the Air District cannot under any circumstances adopt a rule requiring operation below what is allowed in current permits, the Air Disagrees. However, as expressed in the staff report, Air District staff does have concerns regarding taking such an action in the present circumstances.

In addition, the Staff Report explains that, if adopted, the emissions limits shown for each pollutant in Rule § 12-16-300 would need to be adjusted over time for various reasons, including, for example, as emissions measurement methods are improved, new information on criteria pollutants becomes available, or new regulations are adopted. Staff Report, at 23. However, no adjustments to the emissions limits would be made to accommodate new projects permitted through the NSR process, or recent projects permitted through the NSR process but still under construction. While this was an "intended consequence" of CBE's concept, it is an arbitrary and unjustified limitation on the permitting of new refinery projects. Staff Report, at 23. The Staff Report fails to describe how this limitation is necessary or within the District's authority. More importantly, this would directly conflict with existing policies and programs for permitting new projects in the Bay Area. The Clean Air Act (CAA) requires that the District's permitting program allow emissions increases at a facility as long as emissions are offset by an equal or greater amount of reductions of the same pollutant(s) from a location within the region. Staff Report, at 37. As the Staff Report explains, "Rule 12-16 would, in effect, eliminate that option for refineries and would require all emission increases to be offset within the individual facility." Staff Report, at 23. Thus, Rule 12-16 would directly conflict with the intent of the federal CAA and the District's NSR program to provide facilities with the maximum operational flexibility possible, within the constraints of the overall emissions limits that EPA, the State, and the District have determined are necessary to protect health and the environment. It would also disincentive refineries from investing in improvements to refinery facilities and technology, which technology could be intended to ultimately reduce a refinery's emissions.

Staff Response: Air District staff does not recommend Rule 12-16 in its current form because of the legal concerns expressed in the staff report. However, it seems unlikely that refineries would need permits for increased emissions if the end intent of a project is to "ultimately reduce" refinery emissions.

GHG Caps are Ineffective, Counterproductive, and Inconsistent with Current State Efforts

Rule 12-16 would impose an enforceable limit on a refinery's direct emissions of GHGs. WSPA remains opposed to the localized regulation of GHG emissions from existing Bay Area refinery operations by the District. GHG emissions contribute to a global, not local, challenge; the local GHG regulation of refineries in the Bay Area Air Quality District are likely to simply shift GHG emissions elsewhere in the State or nation.3 This has been recognized by District staff, the District's Advisory Council, CARB, and the Intergovernmental Panel on Climate Change.4 Furthermore, the potential for rulemaking at multiple levels of government can lead to duplication of effort; or, of even more concern, regulations that work at cross purposes and undermine the effectiveness and efficiency of regulatory programs. WSPA supports pragmatic, market-based approaches to meeting California's climate goals, and is therefore concerned that the District's proposed GHG caps would undermine and interfere with the comprehensive refinery GHG regulations that CARB is developing as part of its state-wide GHG reduction scheme.

Given the significant existing efforts at the State level to regulate GHGs, Rule 12-16 raises significant concerns with the "authority," "consistency," and "nonduplication" requirements under the Health & Safety Code. As the Staff Report acknowledges, GHGs are regulated under the federal CAA and the California Global Warming Solutions Act (AB 32). AB 32 requires CARB to develop a comprehensive approach that California will take to reduce GHG emissions to levels mandated by the Legislature. In 2016, the California Legislature approved SB 32, which extends California's GHG emissions targets through 2030, with an objective of achieving a 40% reduction in emissions as compared to 1990 levels.

Although local regulations may reduce Bay Area GHG emissions, there remains a real potential for these regulations to increase global GHG emissions, which would work at cross-purposes to California's climate goals. The five Bay Area refineries that are the target of these rules represent some of the most efficient, highly-regulated refineries in the world. Ordering these refineries to reduce GHG emissions may require them to pursue a variety of different options, including curtailing production operations (which would necessarily increase production elsewhere to meet the demand for the products these refineries create) to meet the proposed requirements. To the extent that these options simply result in more processing by refineries that are not local, they result in no reduction in global GHGs; indeed, they would likely increase overall GHG emissions, as non-California refineries increase production to offset the decreases in production from the Bay Area.

Response to Comment: CARB has commented that Rule 12-16 (and 13-1) could help ensure no increases of pollutants. The Air District looks forward to working with CARB through an industrial source action committee of CAPCOA. Air District staff remains concerned about the leakage described by WSPA. However, with improving gas mileage, gasoline consumption is projected to decrease in the future by both CARB and the EIA. Given that the caps are consistent with current production capacity, the leakage described by WSPA seems unlikely.

On January 20, 2017, CARB released its proposed "2017 Climate Change Scoping Plan Update" (the "Proposed Scoping Plan") – its fifth update to the Scoping Plan, which specifically implements the new targets imposed by SB 32.5 CARB has announced numerous public hearings on the Proposed Scoping Plan to take place in 2017, and is currently engaged in extensive efforts to improve and finalize the Proposed Scoping Plan and amendments to CARB's current GHG regulations. The cornerstone of the Proposed Scoping Plan is California's Cap-and-Trade Program, which is a comprehensive, economy-wide program to reduce GHG emissions in California.

In addition to AB 32 and SB 32, AB 197 compels CARB to prioritize "[e]mission reduction rules and regulations that result in direct emission reductions at large stationary sources of greenhouse gas emissions." Cal. H&S Code § 38562.5. Again, the Proposed Scoping Plan addresses these obligations, imposing "prescriptive regulations for refineries that would reduce greenhouse gases" and other air emissions, and in particular targeting a "20 percent reduction in greenhouse gas emissions from the refinery sector." Proposed Scoping Plan at ES3, ES5. The Legislature's decision to authorize CARB – and not the District – to seek these direct GHG emissions reductions continues its longstanding strategy of harmonizing GHG reductions at the state level, not within individual air districts.6

Even assuming the District had the authority to implement Rule 12-16, at best, that rule would merely duplicate the program developed by CARB, in violation of the "nonduplication" requirement. At worst, Rule 12-16 has the potential to interfere with CARB's efforts to implement its own regulations in a reasoned and effective manner, in violation of the "consistency" requirement. CARB is not planning to adopt refinery-focused GHG measures until at least late June, 2017. WSPA is concerned that the District's decision to proceed with GHG emissions caps at this time – before CARB itself has evaluated the available options and determined the most appropriate course of action – will instead create a duplicative, potentially inconsistent, and unnecessary regulatory scheme, and interfere with an orderly implementation of the Proposed Scoping Plan.

Further, refineries already are extensively regulated for GHG emissions. They are subject to California's Cap-and-Trade program; they must comply with CARB's Low Carbon Fuel Standard (which already regulates the carbon intensity of transportation fuels); and they will soon be subject to another statewide program aimed at further direct reductions in refinery GHG emissions once CARB determines the appropriate course of action. Given CARB's prior success in reducing GHG emissions across California, and the Legislature's express grant of authority to CARB to regulate in this area, the District's efforts are unnecessary, disruptive, and will impose a layer of burdensome bureaucracy that has little or no environmental benefit.

Staff Response: CARB has commented that Rule 12-16 (and 13-1) could help ensure no increases of pollutants. The Air District looks forward to working with CARB through an industrial source action committee of CAPCOA. However, it is unclear what the result of that effort would be or how long it would take. In the meantime, refinery GHG emissions have not been decreasing.

Rule 12-16 is Not Within the District's Authority to Adopt

In proposing a new rule or regulation, H&SC § 40001 requires that the District "determine that there is a problem that the proposed rule or regulation will alleviate and that the rule or regulation will promote the attainment or maintenance of state or federal ambient air quality standards[.]" Id. § 40001(c). As discussed above, the District has not identified an air quality problem that would justify the numeric emissions caps in Rule 12-16, nor has the District demonstrated that Rule 12-16 would promote the attainment or maintenance of the NAAQS. This is because Rule 12-16 addresses a problem that may occur; the District does not have the authority under the federal Clean Air Act to adopt regulations that do not address existing air quality issues.

While CARB may elect "to partner with California's local air districts," it has yet to determine whether to do so and is currently considering a range of possibilities.

Staff Response: Air District staff does not recommend Rule 12-16 in its current form because of the legal concerns expressed in the staff report.

Emissions Caps Based on Historical Emissions are Technically Problematic

WPSA incorporates by reference its discussion of this issue in WSPA's comment letter dated November 29, 2016. *(Staff note: date of letter was 12/4/2016.)*

Not only are the proposed emissions caps in §§ 12-16-301 to -305 duplicative of existing federal and state programs targeted at reducing toxic emissions, they are also technically problematic and could potentially require refineries to cut production altogether or risk non-compliance.

As WSPA has previously described, facilities purchase capital equipment today based on what may happen in the future. The District, and every other air permitting jurisdiction in the United States, issues air permits based on the impacts of a facility's potential emissions. In California, refineries pay to offset the potential emissions at the time the equipment is permitted. For the District to now propose capping emissions based on actual emissions levels from 2010-2014 raises significant Takings concerns and conflicts with these other District regulatory programs (which continue to exist). Further, the proposed emissions caps in §§ 12-16-301 to -305 would be inconsistent with refineries' existing permit limits, which in most cases were specifically designed (and paid for) by the refineries to ensure necessary operational flexibility.

Staff Response: Air District staff does not recommend Rule 12-16 in its current form because of the legal concerns expressed in the staff report.

The specific historical emissions baselines chosen are similarly problematic. First, refineries have found that the values in the proposed regulation that are supposedly based in reported emissions do not match the official records of reported emissions.

Staff Response: Air District staff has been working with each facility to identify and reconcile any discrepancies If there are any remaining discrepancies, WSPA needs to identify them specifically.

Second, as the District's own Staff Report makes clear, the selected baseline period encompasses a period of artificially low demand, coming out of the last Recession. Staff Report at page 21, Figure 3. As a result, Rule 12-16, as currently drafted, would "lock in" this temporary drop in demand as a permanent, facility-wide cap. At a minimum, the District's economic analysis must evaluate the significant impacts of imposing the cap at such an artificially low level that does not reflect current or anticipated future demand.

Staff Response: Rule 12-16 provides +7% increase in emissions and production capacity from each refinery's highest annual emissions during the baseline period from 2010 – 2015, and is adequate to supply the Bay Area's current transportation fuel needs. Future needs are uncertain, as population growth is anticipated to be offset by increased use of mass transit, improved fuel economy, and more alternate fuel vehicles. Projections by the Energy Information Administration indicate total transportation fuels are expected to peak at approximately 7% above the baseline period in 2018, at a level 4% less than the peak fuel demand in 2007.

The methodology by which this cap is calculated and revised also raises significant concerns. As currently drafted, Rule 12-16 would require ongoing revisions to these caps (each of which would require Board approval) whenever the methods used to calculate emissions changed. Yet the proposed baselines in §§ 12-16-301 to -305 are themselves based on annual emissions calculations from years 2010-2014 that were developed using different emissions calculation methodologies than are being used today. In other words, the current rule is comparing apples and oranges: the District calculated historic actual emissions (the values that the proposed caps are based on) differently than it currently requires actual emissions to be calculated, and differently than it will require the caps be recalculated in the future when the methodologies change once again; yet these changes are never evaluated for consistency against the original methodology that was used to calculate the initial cap. As a result, the caps under which the Refineries will be required to operate will routinely fluctuate based solely on methodology changes, which may not accurately reflect the “real” emissions that the caps purportedly reflect. For most sources, the District’s current emissions inventory guidelines (Guidelines) significantly deviate from the methods that the District has used in previous years. The Guidelines require reporting emission sources, including cargo carriers, road dust, and equipment maintenance emissions, which the District has not included in previous emission inventories. The Guidelines specify emission factors that may not have been used in previous emission inventories. Similarly, in the case of California’s GHG reporting rule, there have been changes with respect to which sources are reported and how they had to go through a regulatory approval process.

The nature of the Guidelines themselves further exacerbates this concern. The District’s current Guidelines are not yet finalized, meaning that WSPA and its members cannot fully and fairly evaluate how the final Guidelines may change the calculation methodologies as compared to the prior reported emissions inventories on which the caps are based. Furthermore, these Guidelines can be changed at any point in the future without a public Board action – and frequently, as the District’s own practice has made clear, without involving or informing stakeholders. Thus, the refineries may not have sufficient time to respond or even be informed of changes to the Guidelines that affect compliance with the limits. Board approval of changes to the limits that incorporate changes to the Guidelines may never occur, or may occur at a date too late for refineries to comply with the annual limit.

Similarly, the “Determination of Compliance Procedure” in § 12-16-601 refers to an as-yet unwritten part of the District’s Manual Of Procedures. If the compliance procedure is not finalized by rule adoption, it may not be possible for the refineries to comply. Sufficient time is needed to implement compliance.

Finally, the January 1, 2018 compliance deadline does not provide enough time for refineries to comply with Rule 12-16. The refinery emissions estimates using the Guidelines may not even be finalized by January 1, 2018 due to the iterative review, corrective action, APCO Action and public inspection process provided in § 12-15-402. Once the emission calculation methods and estimates are finalized, baseline emissions would need to be updated in order to obtain Board approval of changes to the limits. The emission estimation method must be finalized for a refinery to implement a compliance program. The refineries cannot reasonably plan to comply with Rule 12-16 by January 1, 2018, when the actual emissions limits – or, indeed, even the methodology by which those limits will be determined – may well be unknown as of that date.

Staff Response: Air District staff agrees that as methods for the emissions inventory guidelines improve, adjustments to the emissions limits will be required. These adjustments will go through the rule-making process with ample opportunity for comment, and lead-time for implementation. However, this is not an issue for the GHG portion of the rule. For those emissions, the methodology used to determine the baseline period and the methodology to determine compliance are the same.

AGENDA 4D - ATTACHMENT

March 8, 2016

Socioeconomic Impact Analysis of Proposed Rule 12-16 Regulation 12, Miscellaneous Standards of Performance; Rule 16, Petroleum Refining Facility-Wide Emissions Limits

Prepared for:

Bay Area Air Quality Management District

Prepared by:

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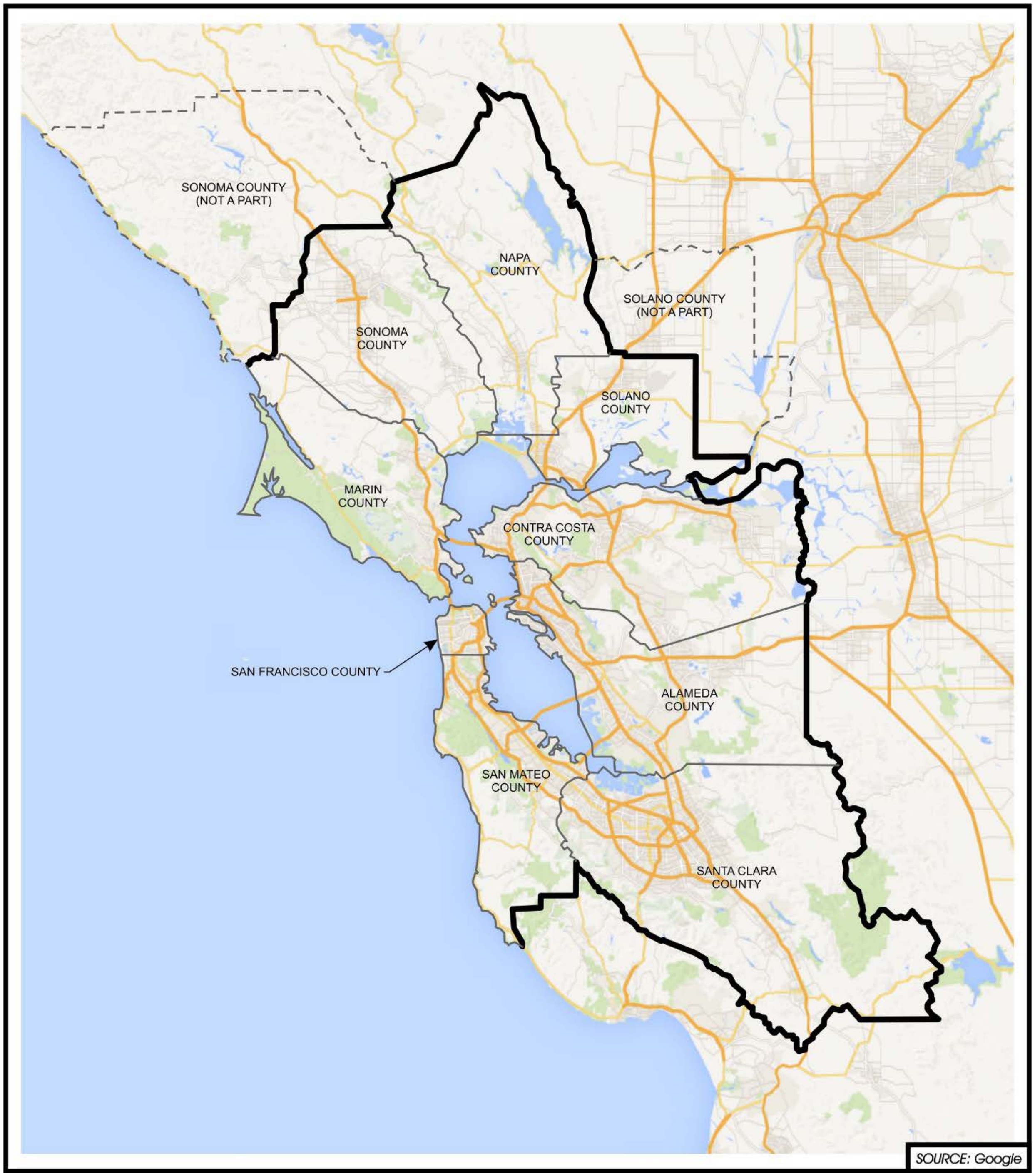
1. INTRODUCTION

In response to concerns of harmful pollutants emanating from petroleum refineries operating in the nine-county San Francisco Bay Area region, particularly with respect to greenhouse gases and toxic air contaminants and criteria pollutants, the Board of Directors of the Bay Area Air Quality Management District (Air District) directed staff to bring forward two proposed rules for their consideration. At the request of the Board, District staff has prepared one proposed rule that reflect policies recommended by environmental advocacy organizations, and a second that follows an approach recommended by District staff. Air District staff has developed proposed "Regulation 12, Miscellaneous Standards of Performance; Rule 16, Petroleum Refining Facility-Wide Emissions Limits (Rule 12-16)" based on input by a consortium of environmental groups in the region including Communities for a Better Environment (CBE). A key provision sought by CBE is a cap on refinery combustion emissions at levels consistent with refineries' recent operations. In addition, proposed Rule 12-16 establishes emissions limits for greenhouse gases (GHG's), nitrogen oxides (NOx), sulfur dioxide (SO2), and particulate matter 10 microns and smaller (PM_{10}) and particulate matter 2.5 microns and smaller ($PM_{2.5}$).

After this introduction, this report discusses in greater detail proposed Rule 12-16 (Section Two). After that discussion, the report describes the socioeconomic impact analysis methodology and data sources (Section Three). The report describes population and economic trends in the nine-county San Francisco Bay Area (Section Four), which serves as a backdrop against which the Air District is contemplating the three sets of rule changes. Finally, the socioeconomic impacts stemming from the proposed rule changes are discussed in Section Five. The report is prepared pursuant to Section 40728.5 of the California Health and Safety Code, which requires an assessment of socioeconomic impacts of proposed air quality rules. The findings in this report can assist Air District staff in understanding the socioeconomic impacts of the proposed requirements, and can assist staff in preparing a refined version of the rule. Figure 1 is a map of the nine-county region that comprises the San Francisco Bay Area Air Basin.

Figure 1 – Map of San Francisco Bay Area Region



SOURCE: Google

2. BACKGROUND AND OVERVIEW OF PROPOSED RULE 12-16

Proposed Rule 12-16 would apply to the five large refineries operating in the Bay Area. These are Chevron Products Company (BAAQMD Plant #10 in Richmond), Phillips 66 Company Refinery (BAAQMD Plant #21359 I Rodeo), Shell Martinez Refinery (BAAQMD Plant #11 in Martinez), Tesoro Refining and Marketing Company (BAAQMD Plant #14628 in Martinez), and Valero Refining Company (BAAQMD Plant #12626 in Benicia). Three facilities that support a number of these facilities would also be affected. These are Air Products and Chemicals hydrogen plant (BAAQMD Plant #10295), Air Liquide hydrogen plant (BAAQMD Plant #17419), and Martinez Cogen, L.P. (BAAQMD Plant #1820). Proposed Rule 12-16 sets the emission limits for each affected facility. The emissions limits cover greenhouse gases (GHG), sulfur dioxide (SO_2), nitrogen oxides (NOx), particulate matter less than 2.5 microns ($PM_{2.5}$), and particulate matter less 10 microns (PM_{10}).

Each refinery and support facility would report emissions based on the requirements in proposed Rule 12-15, Section 401. The District would review and approve the annual emissions inventory per Rule 12-15, Section 402. District staff would then take the steps needed to exclude flare and cooling tower emissions from the annual emissions inventory, where needed. Refinery and support facility emissions for each pollutant, after exclusions, would be compared to the emissions limits established in Rule 12-16, Section 300. Determination of compliance is described in the staff report prepared for Rule 12-16.

In the case of proposed Rule 12-16, District staff report that there are two general scenarios to consider when evaluating the impact of capping refining emissions. In one general scenario, the refineries decide to make physical improvements in order to reduce emissions to allow for increases in refining capacity while staying below the cap. In this first scenario, a refinery may elect to put in a wet scrubber to reduce PM and SO_2 emissions. In the other general scenario, refineries elect to limit production to a level consistent with the cap.

3. METHODOLOGY

Applied Development Economics (ADE) began this analysis by preparing a statistical description of the industry groups of which the affected sources are a part, analyzing data on the number of establishments, jobs, and payroll. We also estimated sales generated by impacted industries, as well as net profits for each affected industry.

This report relies heavily on the most current data available from a variety of sources, particularly InfoUSA. In addition, this report relies on data from the US Census County Business Patterns, as well as from the US Internal Revenue Service. ADE also utilized employment data from the California Employment Development Department – Labor Market Information Division (EDD LMID).

With the above information, ADE was able to estimate net after tax profit ratios for sources affected by the proposed rule. ADE calculated ratios of profit per dollar of revenue for affected industries. The result of the socioeconomic analysis shows what proportion of profits the compliance costs represent. Based on assumed thresholds of significance, ADE discusses in the report whether the affected sources are likely to reduce jobs as a means of recouping the cost of rule compliance or as a result of reducing business operations. To the extent that such job losses appear likely, the indirect multiplier effects of the jobs losses are estimated using a regional IMPLAN input-output model. In some instances, particularly where consumers are the ultimately end-users of goods and services provided by the affected sources, we also analyzed whether costs could be passed to households in the region.

When analyzing the socioeconomic impacts of proposed new rules and amendments, ADE attempts to work closely within the parameters of accepted methodologies discussed in a 1995 California Air Resources Board (ARB) report called “Development of a Methodology to Assess the Economic Impact Required by SB513/AB969” (by Peter Berck, PhD, UC Berkeley Department of Agricultural and Resources Economics, Contract No. 93-314, August, 1995). The author of this report reviewed a methodology to assess the impact that California Environmental Protection Agency proposed regulations would have on the ability of California businesses to compete. The ARB has incorporated the methodologies described in this report in its own assessment of socioeconomic impacts of regulations generated by the ARB. One methodology relates to determining a level above or below which a rule and its associated costs is deemed to have significant impacts. When analyzing the degree to which its rules are significant or insignificant, the ARB employs a threshold of significance that ADE follows. Berck reviewed the threshold in his analysis and wrote, “The Air Resources Board’s (ARB) use of a 10 percent change in [Return on Equity] ROE (i.e. a change in ROE from 10 percent to a ROE of 9 percent) as a threshold for a finding of no significant, adverse impact on either competitiveness or jobs seems reasonable or even conservative.”

4. ECONOMIC AND DEMOGRAPHIC TRENDS

This section of the report discusses the larger context within which the Air District is contemplating proposed Rule 12-16. This section begins with a broad overview of demographic and economic trends, with discussion then narrowing to industries and sources affected by the proposed rule.

REGIONAL POPULATION TRENDS

Table 1 tracks population growth in the nine-county San Francisco Bay Area between 2006 and 2016, including data for the year 2011. Between 2006 and 2017, the region grew by approximately 1.0 percent a year. Between 2011 and 2016, the region grew annually at a somewhat faster rate of 1.2 percent per year. Overall, there are 7,649,565 people in the region. At 1,927,888 Santa Clara County has the most people, while Napa has the least, at 142,028. Santa Clara grew the fastest between 2011 and 2016, at 1.3 percent a year, while Marin grew by the slowest rate (0.6 percent a year) over the same period.

Table 1: Population Trends: Bay Area Counties, Region, and California

JURISDICTION	2006	2011	2016	06-11 CAGR	11-16 CAGR	06-16 CAGR
California	36,116,202	37,536,835	39,255,883	0.8%	0.9%	0.8%
SF Bay Area	6,915,872	7,220,443	7,649,565	0.9%	1.2%	1.0%
Alameda	1,462,371	1,525,695	1,627,865	0.9%	1.3%	1.1%
Contra Costa	1,007,169	1,059,495	1,123,429	1.0%	1.2%	1.1%
Marin	246,969	253,964	262,274	0.6%	0.6%	0.6%
Napa	131,330	136,913	142,028	0.8%	0.7%	0.8%
San Francisco	781,295	815,854	866,583	0.9%	1.2%	1.0%
San Mateo	699,347	726,305	766,041	0.8%	1.1%	0.9%
Santa Clara	1,706,676	1,803,362	1,927,888	1.1%	1.3%	1.2%
Solano	410,964	413,438	431,498	0.1%	0.9%	0.5%
Sonoma	469,751	485,417	501,959	0.7%	0.7%	0.7%

Source: ADE, Inc., based on California Dept. of Finance E-5 Reports (note: CAGR = compound annual growth rate)

REGIONAL ECONOMIC TRENDS

Data in Table 2 describe the larger economic context within which officials are contemplating the proposed Rule 12-16. Businesses in the region employ almost three and a half million workers, or 3,431,643. The number of private and public sector jobs in the region grew annually by 3.0 percent between 2010 and 2015, after having declined slightly between 2005 and 2010 by 0.6 percent a year. Of the 3,431,643 workers, 168,837, or 4.9 percent, are civil servants in the public sector. This figure does not include public sector education, which was combined with private sector education and placed in the private sector portion of the table, in an effort to present a picture as to the total number of persons in the education profession in the Bay Area. The most current annual employment data are for the year 2015 as California EDD has not yet posted detailed all-year 2016 employment data.

Table 2 — San Francisco Bay Area Employment Trends By Sector: 2005 - 2015

INDUSTRY SECTOR		2005	2010	2015	2015	2015 CA	SFBA CAGR* 05-10	SFBA CAGR 10-15	CA CAGR 05-10	CA CAGR 10-15
Total		**3,049,802**	**2,963,021**	**3,431,643**	**100.0%**	**100.0%**	**-0.6%**	**3.0%**	**-1.1%**	**2.3%**
Private Sector		2,869,200	2,774,555	3,262,806			-0.7%	-0.7%	3.3%	2.6%
62	Health	300,775	340,492	453,880	13.2%	13.9%	2.5%	5.9%	2.5%	6.5%
54	Prof., Scientific	293,262	322,617	417,902	12.2%	7.4%	1.9%	5.3%	1.2%	3.2%
44-45	Retail	335,744	306,798	340,197	9.9%	10.2%	-1.8%	2.1%	-1.8%	1.8%
31-33	Manufacturing	350,962	305,378	326,362	9.5%	7.9%	-2.7%	1.3%	-3.8%	0.7%
722	Food Srv, Drnkng	214,142	227,750	288,896	8.4%	8.0%	1.2%	4.9%	0.6%	4.2%
561	Admin. Support	170,727	157,319	192,097	5.6%	6.2%	-1.6%	4.1%	-2.4%	4.2%
61	Education	185,310	192,195	180,382	5.3%	8.5%	0.7%	-1.3%	0.1%	0.8%
23	Construction	188,473	129,820	171,403	5.0%	4.4%	-7.2%	5.7%	-9.2%	4.9%
51	Information	112,690	110,725	158,943	4.6%	2.9%	-0.4%	7.5%	-2.1%	2.2%
42	Wholesale	124,390	113,072	125,215	3.6%	4.4%	-1.9%	2.1%	-0.9%	2.1%
81	Other Services	140,159	155,133	121,676	3.5%	3.2%	2.1%	-4.7%	0.9%	-6.6%
52	Finance, Insrnce	151,375	118,163	120,272	3.5%	3.2%	-4.8%	0.4%	-4.4%	0.4%
55	Mgt. of Comp.	54,856	55,605	75,726	2.2%	1.4%	0.3%	6.4%	-2.9%	3.6%
48-49	Trnsprt-Warehsng	51,880	46,721	72,947	2.1%	2.9%	-2.1%	9.3%	-1.0%	3.6%
71	Culture	49,572	52,315	58,669	1.7%	1.8%	1.1%	2.3%	0.6%	3.0%
53	Real Estate	61,402	52,676	57,463	1.7%	1.7%	-3.0%	1.8%	-2.7%	1.6%
721	Accommodation	46,156	44,734	49,490	1.4%	1.3%	-0.6%	2.0%	-0.5%	1.9%
99	Unclassified	338	6,846	18,517	0.5%	0.6%	82.5%	22.0%	-5.5%	12.2%
11	Agriculture	20,082	18,009	14,069	0.4%	2.6%	-2.2%	-4.8%	0.1%	1.9%
562	Waste Mgt.	10,333	11,018	11,866	0.3%	0.3%	1.3%	1.5%	0.7%	3.1%
22	Utilities	4,603	6,367	5,254	0.2%	0.4%	6.7%	-3.8%	0.4%	0.1%
21	Mining	1,969	802	1,584	0.0%	0.2%	-16.4%	14.6%	2.1%	2.1%
Public Sector**		180,602	188,466	168,837	5.0%	6.8%	0.9%	-2.2%	0.4%	-0.8%

*Source: Applied Development Economics, based on State of California, Employment Development Department Labor Market Information Division, "Quarterly Census of Employment and Wages" (*Note: CAGR = compound annual growth rate \ **Note: Public sector education placed in Private Sector NAICS 61 -- similarly Public sector health placed into NAICS 62).*

Economic sectors in the table above are sorted by the share of total employment. The top-five sectors in the Bay Area in terms of total number of workers are Health and Social Assistance (NAICS 62) (453,880 workers), Professional/Technical Services (NAICS 54) (417,902 workers), Retail (NAICS 44-45) (340,197), Manufacturing (NAICS 31-33) (326,362) and Food Services (288,896). Of the top-ten leading sectors in terms of employment, six exhibited high rates of annual growth from 2010 to 2015, growing annually by more than four percent. These sectors are Health and Social Assistance (5.9 percent per year), Professional/Technical Services (5.3 percent), Food Services (4.9 percent), Administrative Support (NAICS 561) (4.1 percent), Construction (NAICS 23) (5.7 percent per year) and Information (NAICS 51), which grew at a phenomenal annual rate of 7.5 percent. Combined, these five sectors employ 49 percent of total employment, or 1,683,121 out of 3,374,902. Moreover, of the top-ten leading sectors in the Bay Area, only one (Public Sector) had less workers in 2015 than in 2010, underscoring the resilience of the regional economy in the aftermath of the Great Recession. The table also demonstrates the advanced nature of the regional economy, as 12.2 percent of all workers are in the Professional, Scientific and Technical classification (NAICs 54), whereas in the state, as a whole, 7.4 percent of all workers are in this sector. Interestingly, at 1.3 percent per year, manufacturing employment growth in the Bay Area almost doubled statewide manufacturing growth rates (0.7 percent), underscoring the diversity of the regional economy.

TRENDS FOR INDUSTRIES SUBJECT TO PROPOSED RULE 12-16

Proposed Rule 12-16 would primarily affect refineries (NAICS 324110). However, two support industries (containing three non-refinery firms) would be affected as well. Two of the three non-refineries (Air Liquide and Air Products and Chemicals) operate hydrogen plants, and these are within the industry known as industrial gas manufacturing (NAICS 325120). A third firm is a co-generation plant (Martinez Cogen, L.P), which is classified as “other electric power” (NAICS 221118). The economic data in the table below comes from the US Census County Business Patterns.[1] As indicated in the table below, all industries subject to the proposed rule have yet to recover from the Great Recession, the lowest national point of which occurred in the years 2009 and 2010. In 2009, large refineries employed an estimated 3,976 workers in the Bay Area, which is over 700 more workers than today, or 3,269. Similarly, industrial gas manufacturing (NAICS 325120) has yet to recover from the Great Recession, at 252 workers today versus 413 in 2009.

Table 3: Trends for Industries Subject to Proposed rule 12-16: SF Bay Area: 2009-2014

ESTABLISHMENTS	NAICS	2009	2010	2011	2012	2013	2014	09-14 CHG	09-14 CAGR**
Refineries*	324110	7	8	7	5	17	12	5	11.4%
Large refineries		*5*	*5*	*5*	*5*	*5*	*5*	*0*	*0.0%*
Industrial Gas Manuf.	325120	16	14	14	15	13	12	-4	-5.6%
Other Electric Power	221118	18	23	29	11	7	8	-10	-15.0%
EMPLOYMENT									
Refineries	324110	4,051	3,706	3,704	3,622	3,726	3,574	-477	-2.5%
Large refineries		*3,976*	*3,622*	*3,622*	*3,622*	*3,622*	*3,269*	*-708*	*-3.8%*
Industrial Gas Manuf.	325120	413	295	396	397	210	252	-161	-9.4%
Other Electric Power	221118	146	218	358	139	104	130	-17	-2.4%

Source: Applied Development Economics, based on US Census County Business Patterns 2009-2014. ***Note:** *The proposed rule changes affects five refineries. Both County Business Patterns and the EDD LMID report more than five refineries in the nine-county region, which is because both apply a broader definition for refinery operations. **CAGR= compound annual growth rate.*

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[1] When analyzing industry employment trends, we typically use California EDD LMID data. However, while the EDD LMID indicate the presence of a number of establishments in any of the three industries above in Bay Area counties, for a number of Bay Area counties, the EDD LMID data set did not precisely identify the number of establishments or number of workers, replacing numbers with an asterisk mark, thus making difficult any analysis of EDD LMID data. As a result, we used US Census County Business Patterns, which provides enough county-level data to allow us to track trends. However, the most current County Business Pattern data is for the year 2014.

5. SOCIOECONOMIC IMPACT ANALYSIS OF PROPOSED RULE 12-16

This section of the report analyzes socioeconomic impacts stemming from proposed Rule 12-16. The analysis is divided into two sections, with the first covering impacts based on the first scenario contemplated by District staff, in which affected sources implement scrubbers to achieve the aims of proposed Rule 12-16. In the second part, we present our determination of possible impacts resulting from a production limit.

SECTION ONE: NON-REGENERATIVE AND REGENERATIVE SCRUBBERS

The discussion begins first with a summary of costs associated with the rule. Then, we present our findings with regard to estimated revenues and profits generated by the five affected refineries and three non-refineries, comparing the cost of proposed rule against estimated net profits, in an effort to determine if the rule would significantly impact the affected industry.

Cost of Compliance

In the event affected sources adopt physical improvements to comply with proposed Rule 12-16, District staff has indicated that affected sources will adopt one of two scrubbers, i.e. a FCCU non-regenerative scrubber or a FCCU regenerative scrubber. According to District staff, one FCCU non-regenerative scrubber with a flow rate of 275,000 dry standard cubic feet per minute (dscfm) annually costs $6,336,978. Of this amount, $5,170,880 is the annual capital cost associated with a non-regenerative scrubber, with the balance at $1,166,098 the annual operating cost associated with maintaining this scrubber. District staff places the annual cost of one FCCU regenerative scrubber with a flow rate of 275,000 dscfm at $12,818,246. Of this amount, $10,999,872 is the cost of the equipment, and $1,818,374 is the annual operating cost.

Of the five large refineries in the Bay Area, three could adopt scrubbers, with each implementing one, i.e. either a non-regenerative scrubber or a regenerative scrubber. It is important to note that these three refineries could choose to adopt scrubbers to comply with the proposed measure because they operate units that are subject to Rule 12-16. Furthermore, three non-refineries subject to the proposed measure do not need to consider installing scrubbers as they do not operate what are called FCC units.

In the table below we estimate the annual cost of compliance associated with proposed Rule 12-16, should affected sources achieve the aims of the proposed rule by adopting new equipment to stay below the emission cap. If the three refineries in need of implementing a scrubber did so, they would face a combined annual cost ranging from $19.0 million to $38.4 million.

Table 4: Aggregate Annual Capital and Operating Cost By Affected Industry: Low Scenario and High Scenario

INDUSTRY	NAICS	NOS OF. EQUIPMENT	LOW SCENARIO (NON-REGENERATIVE SCRUBBER)	HIGH SCENARIO (REGENERATIVE SCRUBBER)
Refineries	324111	3	$19,010,934	$38,454,739
Others				
Industrial Gas Manufacturing	325120	na	na	na
Other Electric Power	221118	na	na	na

Profile of Affected Sources

Based on information from a variety of sources, such as InfoUSA, California Energy Commission, the US Energy Information Administration, US Internal Revenue Service, and the Economic Census, ADE has prepared an economic profile of sources affected by the proposed rule. The three affected refineries (NAICS 324111) generate an estimated $26.6 billion in combined annual revenues and $1.0 billion in net profits. The two industrial gas manufacturers (NAICS 325120) generate anywhere between $200 million and $500 million in combined revenues, and between $15 million and $25 million in annual profits. Martinez CoGen (NAICS 221118) generates between $5 million and $15 million in annual revenues, and $225,000 to $500,000 in net profits.

Table 5: Economic Profile of Sources Affected By Proposed Rule 12-16

INDUSTRY	NAICS	ESTABLISHMENTS	EST. ANNUAL REVENUES	EST. ANNUAL NET PROFITS
Refineries	324111	3	$26,574,614,058	$1,064,599,599
Others				
Industrial Gas Manufacturing	325120	2	$200M - $500M	$15M - $25M
Other Electric Power	221118	1	$5M - $15M	$225K - $500K

Source: Applied Development Economics, based on InfoUSA, California Energy Commission, the US Energy Information Administration, US Internal Revenue Service, and the Economic Census

Socioeconomic Impact Analysis of Proposed Rule 12-16

In both the low or high cost scenarios, the three affected refineries are not significantly impacted by proposed Rule 12-16, should they choose to achieve the emissions-limitation aims of the measure by adopting new scrubbers.

Table 6: Socioeconomic Impact of Proposed Rule 12-16 on Affected Industries

INDUSTRY	NAICS	ESTABLISHMENTS	**Low Scenario**: FCCU Non-Regenerative Scrubber Cost Effectiveness	**High Scenario**: FCCU Regenerative Scrubber Cost Effectiveness	**Low Scenario**: FCCU Non-Regenerative Scrubber Cost Effectiveness: Cost to Net Profit	**High Scenario**: FCCU Regenerative Scrubber Cost Effectiveness: Cost to Net Profit
Refineries	324111	3	$19,010,934	$38,454,739	1.8%	3.6%
Others						
Industrial Gas Manufacturing	325120	2	na	na	na	na
Other Electric Power	221118	1	na	na	na	na

Source: Applied Development Economics

Small Business Disproportionate Impacts

According to the State of California, among other things, small businesses generate annual sales of less than $10 million.[2] Of the three sources affected by the proposed rule, none are small businesses. As a result, small businesses are not disproportionately impacted by proposed Rule 12-16.

SECTION TWO: LIMITING REFINERY PRODUCTION

In this second part of the socioeconomic analysis, we present our determination of possible impacts resulting from a limit on production at refineries. In its staff report for the proposed measure, District staff analyzed a variety of data sources on refinery capacity and utilization, and observed that emissions limits contemplated in proposed Rule 12-16 do not appear to inhibit refining capacity, as the caps in the proposed rule appear to be consistent with the current maximum production capability of area refineries.

One caveat expressed by District staff is that they do not expect the cap in Rule 12-16 to have significant impacts on the market for refined fuels so long as fuel consumption does not significantly increase. Consumption for fuel can increase in absolute and relative terms for a variety of reasons, with a corresponding increase in price of fuel at the retail level. For example, population growth and an increase in the number of persons commuting into the area would result in greater demand for fuel whose supply could be limited by proposed Rule 12-16, resulting in a bidding-up of the price of fuel.

While the impact of a limited supply of refined product relative to demand on the retail price of fuel is observable in that prices tend to go up, how much prices increase can vary widely. Price spikes tend to be an inherent, if latent, feature of the oil refining-gasoline consuming activity, due to the combined facts that people tend to keep buying gas to drive their cars to work and other places even as the price of gas rises, and that California refineries tend to operate very close to capacity, meaning that refineries are unable to boost supply significantly when they need to. As Boorstein notes, “The market can easily become out of balance if there is an unexpected jump in demand, or more commonly, if a refinery experiences a supply disruption or outage and output is reduced.”[3] Thus, in the case of the

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[2] http://www.leginfo.ca.gov/cgi-bin/displaycode?section=gov&group=14001-15000&file=14835-14843

[3] Borenstein, Bushnell, and Lewis, “Market Power in California’s Gasoline Market” (May 2004), page 8

temporary shut-down of the southern Californian refinery in Torrance in 2015, BAAQMD staff quoted a California Energy Commission report that found that the 10 percent reduction in supply led to 27.6 cents increase in the cost of gasoline.[4] ADE estimates that between February 12, 2015 and March 13, 2015 the average price of gasoline in the City of Los Angeles increased by 32 percent as a result of the Torrance shutdown, which occurred on February 18, going from $2.65 a gallon to $3.51 a gallon.[5] The peculiarities of the California market also explain the magnitude of price increases in California when supply shocks occur. By way of example, Phoenix, Arizona in 2003 experienced a 30 percent drop in volume resulting from a pipeline failure, which then led to a 37 percent increase in price of gas in Phoenix.[6] The FTC observed that prices in Phoenix in 2003 did not rise even faster largely because West Coast refineries were able to ship more gasoline into Arizona to hold down prices. The unique blend required in California makes it difficult (but not impossible) to ameliorate the effects of supply shocks along the lines of Phoenix in 2003, which perhaps explains why in one instance a ten percent drop in supply in southern California leads to almost 32 percent increase in price while a steeper 30 percent supply drop in Phoenix at another instance led to 37 percent price increase there.[7]

While the Torrance and the Phoenix examples demonstrate prices could rise by 32 to 37 percent in a short-time due to supply cuts, projecting changes to price following supply shocks is still not an exact science. One could apply the Torrance and Phoenix examples to roughly estimate price impacts. Thus, if production at refineries is capped per the limits contemplated in proposed Rule 12-16, then a percentage increase in population over some time period would be equivalent to a reduction in supply of gasoline by a similar percentage over the same period. Since ABAG projects the nine-county San Francisco Bay Area region to grow by 9.2 percent over the ten-year 2015-2025 period, when we apply the Torrance example, we arrive at an estimated 29.4 percent increase in price over the same ten-year period.[8] This price increase would average less than three percent a year, which would have a cumulative effect but would be much less than a short-term price shock such as occurred in the Torrance incident, or other price fluctuations that occur due to market conditions. For example, in January 2015, regular gasoline in California cost $2.68 per gallon, of which $1.29 was attributable to the price of crude oil purchased by the refinery. Six months later, a gallon of regular gas was $3.45, of which

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[4] Bay Area Air Quality Management District, Draft 12-16 and Draft 11-18 (Draft Staff Report: October 2016) page 23 (citing California Energy Commission)

[5] GasBuddy California http://archive.is/tIKBy

[6] Federal Trade Commission, Gasoline Price Changes: The Dynamic of Supply, Demand, and Competition (2005), page 29

[7] While it is true that California's market for refined product is almost a closed market due to the special blends generated only for Californians, there are some refiners outside of California who produce to California's standard, although delivery of their products takes 2 to 5 weeks and entails prohibitive transport costs. See Borenstein, Bushnell, and Lewis, "Market Power in California's Gasoline Market" (May 2004), page 20 ; see also US EIA, "California's gasoline imports increase 10-fold after major refinery outage" (October 2015) http://archive.is/oRGoI

[8] See http://archive.is/qGomH: The nine-county San Francisco Bay Area region is projected to grow over the ten-year 2015-2025 period by 672,600 persons, from 7,461,400 to 8,134,000. Including estimated number of non-residents commuting daily into the Bay Area for jobs, the total number of persons in the Bay Area will go from 7,938,800 in 2015 to 8,668,700 in 2025, for a 9.2 percent increase over the ten-year 2015-2025 period.

$1.45 was attributable to crude oil, for a 12 percent increase over a six-month period in the cost of a gallon of gas attributable to crude oil.[9] The overall price of gas in this six month-period increased by 29 percent, from $2.68 to $3.45 a gallon. In short, proposed Rule 12-16 would introduce a regime to limit the production of refined petroleum products, but for various reasons, the price of these refined products can go up and down, consequently lessening the effect in modelling the socioeconomic impacts of a limit on the production of refined petroleum products supply on the wider economy.

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[9] See http://bit.ly/2mkDgLW

Final Environmental Impact Report for the Bay Area Air Quality Management District

Regulation 12-16: Petroleum Refining Facility-Wide Emissions Limits

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State Clearinghouse No. 2016102043

May 2017

PREFACE

This document constitutes the Final Environmental Impact Report (EIR) for the Bay Area Air Quality Management District Regulation 12-16: Petroleum Refining Facility-Wide Emissions Limits. The Draft EIR was circulated for a 45-day public review and comment period from March 23, 2016 through May 8, 2017. A total of 21 comment letters and emails were on the Draft EIR. The comments and responses are included in Appendix C of this document. The comments were evaluated and minor modifications have been made to the Draft EIR such that it is now a Final EIR. None of the modifications alter any conclusions reached in the Draft EIR, nor provide new information of substantial importance relative to the draft document that would require recirculation of the Draft EIR pursuant to CEQA Guidelines §15088.5. Therefore, this document is now a Final EIR. In addition, the consideration of Rule 11-18 Risk Reduction from Air Toxic Emissions at Existing Facilities has been removed from this Final EIR. Additional CEQA analysis will be provided when the rule is revised and re-released. Additions to the text of the Final EIR are denoted using underline. Text that has been eliminated is shown using ~~strike outs~~. To avoid confusion, the Table of Contents have been revised but the underline/~~strike out~~ have not been included.

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APPENDIX B

EMISSION CALCULATONS

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Appendix B has been revised. The previous version of Appendix B is presented as ~~STRIKEOUT~~. The revised Appendix B pages are presented following the ~~STRIKEOUT~~ page of Appendix B it replaces (with no STRIKEOUT).

~~ICE Replacement - Emission Factors~~

~~Off- Road Equipment Type~~	~~Numaber~~	~~Daily Hours of Use~~	~~ROG lbs/hr~~	~~CO lbs/hr~~	~~NOx lbs/hr~~	~~SOx lbs/hr~~	~~PM lbs/hr~~	~~CO2 eq MT/hr~~
~~Forklift~~	~~1~~	~~2~~	~~0.02~~	~~0.22~~	~~0.19~~	~~0~~	~~0.01~~	~~0.01~~
~~Generator~~	~~1~~	~~4~~	~~0.05~~	~~0.28~~	~~0.41~~	~~0~~	~~0.22~~	~~0.02~~
~~Welder~~	~~1~~	~~4~~	~~0.04~~	~~0.19~~	~~0.21~~	~~0~~	~~0.02~~	~~0.01~~

~~ICE Replacement lbs/day = number *hrs/day*emission factor~~

~~Off- Road Equipment Type~~	~~ROG lbs/day~~	~~CO lbs/day~~	~~NOx lbs/day~~	~~SOx lbs/day~~	~~PM10 lbs/day~~	~~PM2.5 lbs/day~~	~~CO2 eq MT/d~~
~~Forklift~~	~~0.04~~	~~0.44~~	~~0.38~~	~~0~~	~~0.02~~	~~0.02~~	~~0.02~~
~~Generator~~	~~0.2~~	~~1.12~~	~~1.64~~	~~0~~	~~0.88~~	~~0.88~~	~~0.08~~
~~Welder~~	~~0.16~~	~~0.76~~	~~0.84~~	~~0~~	~~0.08~~	~~0.08~~	~~0.04~~
~~Sub-total off-road lbs/day~~	~~0.4~~	~~2.32~~	~~2.86~~	~~0~~	~~0.98~~	~~0.98~~	~~0.14~~

~~On-Road Equipment Type~~	~~ROG lbs/day~~	~~CO lbs/day~~	~~NOx lbs/day~~	~~SOx lbs/day~~	~~PM10 lbs/day~~	~~PM2.5 lbs/day~~	~~CO2 eq MM t/d~~
~~Construction Worker Light-duty Auto #/day~~	~~0.18~~	~~0.27~~	~~0.02~~	~~0.00~~	~~0.01~~	~~0.00~~	~~0.03~~
~~Heavy-heavy-duty Truck #/day~~	~~0.30~~	~~2.15~~	~~1.88~~	~~0.00~~	~~0.03~~	~~0.02~~	~~0.20~~
~~Sub-totalotal #/day~~	~~0.48~~	~~2.41~~	~~1.91~~	~~0.01~~	~~0.04~~	~~0.02~~	~~0.23~~

~~LD Autos~~	~~Avg. Trip Length~~
~~# Vehicle Trips~~	~~One way~~
~~10~~	~~11~~
~~HHD Truck~~	~~HHD Truck Trips/day~~
~~2~~	~~50~~

	~~ROG lbs/day~~	~~CO lbs/day~~	~~NOx lbs/day~~	~~SOx lbs/day~~	~~PM10 lbs/day~~	~~PM2.5 lbs/day~~	~~CO2 eq MM t/d~~
~~Sub-total Off-road Construction Equip~~	~~0.4~~	~~2.32~~	~~2.86~~	~~0~~	~~0.98~~	~~0.98~~	~~0.14~~
~~Sub-total On-road (Worker + HHD Truck)~~	~~0.48~~	~~2.41~~	~~1.91~~	~~0.01~~	~~0.04~~	~~0.02~~	~~0.23~~
~~Total~~	~~0.88~~	~~4.73~~	~~4.77~~	~~0.005~~	~~1.02~~	~~1.00~~	~~0.37~~

ICE Replacement - Emission Factors

Off- Road Equipment Type	Numaber	Daily Hours of Use	ROG lbs/hr	CO lbs/hr	NOx lbs/hr	SOx lbs/hr	PM lbs/hr	CO2 eq MT/hr
Forklift	1	2	0.02	0.22	0.19	0	0.01	0.01
Generator	1	4	0.05	0.28	0.41	0	0.22	0.02
Welder	1	4	0.04	0.19	0.21	0	0.02	0.01

ICE Replacement lbs/day = number *hrs/day*emission factor

Off- Road Equipment Type	ROG lbs/day	CO lbs/day	NOx lbs/day	SOx lbs/day	PM10 lbs/day	PM2.5 lbs/day	CO2 eq MT/d
Forklift	0.04	0.44	0.38	0	0.02	0.02	0.02
Generator	0.2	1.12	1.64	0	0.88	0.88	0.08
Welder	0.16	0.76	0.84	0	0.08	0.08	0.04
Sub-total off-road lbs/day	0.4	2.32	2.86	0	0.98	0.98	0.14

On-Road Equipment Type	ROG lbs/day	CO lbs/day	NOx lbs/day	SOx lbs/day	PM10 lbs/day	PM2.5 lbs/day	CO2 eq MM t/d
Construction Worker Light-duty Auto #/day	0.18	0.27	0.02	0.00	0.01	0.00	0.03
Heavy-heavy-duty Truck #/day	0.30	2.15	1.88	0.00	0.03	0.02	0.20
Sub-totalotal #/day	0.48	2.41	1.91	0.00	0.04	0.02	0.23

LD Autos	Avg. Trip Length
# Vehicle Trips	One way
10	11
HHD Truck	HHD Truck Trips/day
2	50

	ROG lbs/day	CO lbs/day	NOx lbs/day	SOx lbs/day	PM10 lbs/day	PM2.5 lbs/day	CO2 eq MM t/d
Sub-total Off-road Construction Equip	0.4	2.32	2.86	0	0.98	0.98	0.14
Sub-total On-road (Worker + HHD Truck)	0.48	2.41	1.91	0.00	0.04	0.02	0.23
Total 1 unit Off-road and On-road #/day	0.88	4.73	4.77	0.00	1.02	1.00	0.37
5 units per day	4.38	23.67	23.85	0.02	5.11	5.01	1.86
10 units per day	8.76	47.33	47.69	0.05	10.23	10.02	3.72
15 units per day	13.13	71.00	71.54	0.07	15.34	15.03	5.57

~~ICE Retrofit - Emission Factors~~

~~DPFs - DOCs~~

~~Off- Road Equipment Type~~	~~Numaber~~	~~Daily Hours of Use~~	~~ROG lbs/hr~~	~~CO lbs/hr~~	~~NOx lbs/hr~~	~~SOx lbs/hr~~	~~PM lbs/hr~~	~~CO2 eq MT/hr~~
~~Forklift~~	~~1~~	4	~~0.02~~	~~0.22~~	~~0.19~~	~~0~~	~~0.01~~	~~0.01~~

~~ICE Retrofit lbs/day = number *hrs/day*emission factor~~

~~Off- Road Equipment Type~~	~~ROG lbs/day~~	~~CO lbs/day~~	~~NOx lbs/day~~	~~SOx lbs/day~~	~~PM10 lbs/day~~	~~PM2.5 lbs/day~~	~~CO2 eq MM t/d~~
~~Subtotal Forklift #/day~~	~~0.08~~	~~0.88~~	~~0.76~~	~~0~~	~~0.04~~	~~0.04~~	~~1.8141E-05~~

~~On-Road Equipment Type~~	~~ROG lbs/day~~	~~CO lbs/day~~	~~NOx lbs/day~~	~~SOx lbs/day~~	~~PM10 lbs/day~~	~~PM2.5 lbs/day~~	~~CO2 eq MM t/d~~
~~Construction Worker Light-duty Auto #/day~~	~~0.14~~	~~0.21~~	~~0.02~~	~~0.00~~	~~0.01~~	~~0.00~~	~~0.02732308~~
~~Heavy-heavy-duty Truck~~	~~0.05~~	~~0.18~~	~~1.28~~	~~0.00~~	~~0.03~~	~~0.02~~	~~0.19746489~~
~~Sub-totalotal On-road~~	~~0.19~~	~~0.40~~	~~1.30~~	~~0.00~~	~~0.04~~	~~0.02~~	~~0.22~~

~~Total 1 unit Off-road and On-road #/day~~	~~0.27~~	~~1.28~~	~~2.06~~	~~0.00~~	~~0.08~~	~~0.06~~	~~0.22~~
~~5 units per day~~	~~1.37~~	~~6.39~~	~~10.29~~	~~0.01~~	~~0.40~~	~~0.29~~	~~1.12~~
~~10 units per day~~	~~2.74~~	~~12.78~~	~~20.58~~	~~0.02~~	~~0.80~~	~~0.57~~	~~2.25~~
~~15 units per day~~	~~4.11~~	~~19.17~~	~~30.86~~	~~0.03~~	~~1.20~~	~~0.86~~	~~3.37~~

~~LD Autos~~	~~Avg. Trip Length~~
~~# Vehicle Trips~~	~~One way~~
8	~~11~~
~~HH duty truck trips/day~~	~~Avg. Trip Length~~
2	~~50~~

ICE Retrofit - Emission Factors

DPFs - DOCs

Off- Road Equipment Type	Numaber	Daily Hours of Use	ROG lbs/hr	CO lbs/hr	NOx lbs/hr	SOx lbs/hr	PM lbs/hr	CO2 eq MT/hr
Forklift	1	4	0.02	0.22	0.19	0	0.01	0.01

ICE Retrofit lbs/day = number *hrs/day*emission factor

Off- Road Equipment Type	ROG lbs/day	CO lbs/day	NOx lbs/day	SOx lbs/day	PM10 lbs/day	PM2.5 lbs/day	CO2 eq MM t/d
Subtotal Forklift #/day	0.08	0.88	0.76	0	0.04	0.04	1.8141E-05

On-Road Equipment Type	ROG lbs/day	CO lbs/day	NOx lbs/day	SOx lbs/day	PM10 lbs/day	PM2.5 lbs/day	CO2 eq MM t/d
Construction Worker Light-duty Auto #/day	0.14	0.21	0.02	0.00	0.01	0.00	0.02732308
Heavy-heavy-duty Truck	0.05	0.22	1.58	0.00	0.03	0.02	0.19746489
Sub-totalotal On-road	0.19	0.44	1.60	0.00	0.04	0.02	0.22

Total 1 unit Off-road and On-road #/day	0.27	1.32	2.36	0.00	0.08	0.06	0.22
5 units per day	1.37	6.59	11.81	0.01	0.40	0.29	1.12
10 units per day	2.74	13.17	23.61	0.01	0.80	0.58	2.25
15 units per day	4.11	19.76	35.42	0.02	1.20	0.87	3.37

LD Autos	Avg. Trip Length
# Vehicle Trips	One way
8	11
HH duty truck trips/day	Avg. Trip Length
2	50

~~FCCU with WGS GHG Parameters~~

~~Off- Road Equipment Type~~	~~Amount~~	~~Daily Hours of Use~~	~~CO2 eq MT/hr~~	~~CO2 eq MT/day~~	~~Construction/ period MT~~	~~Days/ Period~~	
~~Demolition~~						~~20.00~~	
~~Crane (140 ton, composite hp)~~	~~1~~	~~10~~	~~0.04~~	~~0.4~~	~~8~~		
~~Front End Loader~~	~~1~~	~~10~~	~~0.02~~	~~0.2~~	~~4~~		
~~Forklift~~	~~2~~	~~10~~	~~0.01~~	~~0.2~~	~~4~~		
~~Demolition Hammer~~	~~1~~	~~10~~	~~0.001~~	~~0.01~~	~~20.01~~		
~~Construction~~						~~160~~	~~2 construction periods~~
~~Air Compressor~~	~~1~~	~~10~~	~~0.02~~	~~0.2~~	~~48~~		
~~Crane (140 ton, composite hp)~~	~~2~~	~~10~~	~~0.04~~	~~0.8~~	~~192~~		
~~Aerial Lift (Man Lift)~~	~~3~~	~~10~~	~~0.01~~	~~0.3~~	~~72~~		
~~Generator~~	~~1~~	~~10~~	~~0.02~~	~~0.2~~	~~48~~		
~~Welder~~	~~3~~	~~10~~	~~0.01~~	~~0.3~~	~~72~~		

~~Total 1 cons. + demo~~	~~468.01~~
~~Total 3 cons. + demo~~	~~1404.03~~
~~Total 5 cons. + demo~~	~~2340.05~~

FCCU with WGS GHG Parameters

Off- Road Equipment Type	Amount	Daily Hours of Use	CO2 eq MT/hr	CO2 eq MT/day	Construction/ period MT	Days/ Period	
Demolition						20.00	
Crane (140 ton, composite hp)	1	10	0.04	0.4	8		
Front End Loader	1	10	0.02	0.2	4		
Forklift	2	10	0.01	0.2	4		
Demolition Hammer	1	10	0.001	0.01	0.20		
Construction						160	2 construction periods
Air Compressor	1	10	0.02	0.2	48		
Crane (140 ton, composite hp)	2	10	0.04	0.8	192		
Aerial Lift (Man Lift)	3	10	0.01	0.3	72		
Generator	1	10	0.02	0.2	48		
Welder	3	10	0.01	0.3	72		

Total 1 cons. + demo	448.20
Total 3 cons. + demo	1344.6
Total 5 cons. + demo	2241

~~FCCU SCR - Parameters~~

~~Off- Road Equipment Type~~	~~Amount~~	~~Daily Hours of Use~~	~~ROG lbs/hr~~	~~CO lbs/hr~~	~~NOx lbs/hr~~	~~SOx lbs/hr~~	~~PM lbs/hr~~	~~CO2 eq MT/hr~~
~~Aerial Lift (Man Lift)~~	~~1~~	~~2~~	~~0.00~~	~~0.17~~	~~0.1~~	~~0.00~~	~~0.00~~	~~0.01~~
~~Air Compressor~~	~~1~~	~~1~~	~~0.06~~	~~0.32~~	~~0.43~~	~~0.00~~	~~0.03~~	~~0.02~~
~~Backhoe~~	~~1~~	~~4~~	~~0.03~~	~~0.36~~	~~0.31~~	~~0.00~~	~~0.02~~	~~0.02~~
~~Concrete Pump~~	~~1~~	~~2~~	~~0.07~~	~~0.4~~	~~0.43~~	~~0.00~~	~~0.03~~	~~0.003~~
~~Concrete Saw~~	~~1~~	~~2~~	~~0.06~~	~~0.41~~	~~0.80~~	~~0.00~~	~~0.04~~	~~0.02~~
~~Crane (140 ton, composite hp)~~	~~2~~	~~10~~	~~0.06~~	~~0.41~~	~~0.80~~	~~0.00~~	~~0.04~~	~~0.04~~
~~Crane - Rough Terrane (28 ton, 120 hp)~~	~~0~~	~~0~~	~~0.07~~	~~0.4~~	~~0.42~~	~~0.00~~	~~0.02~~	~~0.02~~
~~Forklift~~	~~1~~	~~3~~	~~0.02~~	~~0.22~~	~~0.19~~	~~0.00~~	~~0.01~~	~~0.01~~
~~Generator~~	~~2~~	~~8~~	~~0.05~~	~~0.28~~	~~0.41~~	~~0.00~~	~~0.22~~	~~0.02~~
~~Plate Compactor~~	~~1~~	~~4~~	~~0.01~~	~~0.03~~	~~0.03~~	~~0.00~~	~~0.00~~	~~0.001~~
~~Welder~~	~~2~~	~~8~~	~~0.04~~	~~0.19~~	~~0.21~~	~~0.00~~	~~0.02~~	~~0.01~~

~~FCCU with SCR lbs/day = number *hrs/day*emission factor~~

~~Off- Road Equipment Type~~	~~ROG lbs/day~~	~~CO lbs/day~~	~~NOx lbs/day~~	~~SOx lbs/day~~	~~PM10 lbs/day~~	~~PM2.5 lbs/day~~	~~CO2 eq MT/d~~
~~Aerial Lift (Man Lift)~~	~~0.00~~	~~0.34~~	~~0.20~~	~~0.00~~	~~0.00~~	~~0.00~~	~~0.02~~
~~Air Compressor~~	~~0.06~~	~~0.32~~	~~0.43~~	~~0.00~~	~~0.03~~	~~0.0276~~	~~0.02~~
~~Backhoe~~	~~0.12~~	~~1.44~~	~~1.24~~	~~0.00~~	~~0.08~~	~~0.0736~~	~~0.08~~
~~Concrete Pump~~	~~0.02~~	~~0.8~~	~~0.86~~	~~0.00~~	~~0.06~~	~~0.0552~~	~~0.006~~
~~Concrete Saw~~	~~0.12~~	~~0.82~~	~~1.6~~	~~0.00~~	~~0.08~~	~~0.0736~~	~~0.04~~
~~Crane (140 ton, composite hp)~~	~~0~~	~~0~~	~~0~~	~~0.00~~	~~0~~	~~0~~	~~0.8~~
~~Forklift~~	~~0.06~~	~~0.66~~	~~0.57~~	~~0.00~~	~~0.03~~	~~0.0276~~	~~0.03~~
~~Generator~~	~~0.8~~	~~4.48~~	~~6.56~~	~~0.00~~	~~3.52~~	~~3.2384~~	~~0.32~~
~~Plate Compactor~~	~~0.04~~	~~0.12~~	~~0.12~~	~~0.00~~	~~0.00~~	~~0.00~~	~~0.004~~
~~Welder~~	~~0.64~~	~~3.04~~	~~3.36~~	~~0~~	~~0.32~~	~~0.2944~~	~~0.16~~
~~Subtotal lbs/day off-road~~	~~1.86~~	~~12.02~~	~~14.94~~	~~0.00~~	~~4.12~~	~~3.79~~	~~1.48~~
						~~Total~~	~~1.5~~

FCCU SCR - Parameters

Off- Road Equipment Type	Amount	Daily Hours of Use	ROG lbs/hr	CO lbs/hr	NOx lbs/hr	SOx lbs/hr	PM lbs/hr	CO2 eq MT/hr
Aerial Lift (Man Lift)	1	2	0.00	0.17	0.1	0.00	0.00	0.01
Air Compressor	1	1	0.06	0.32	0.43	0.00	0.03	0.02
Backhoe	1	4	0.03	0.36	0.31	0.00	0.02	0.02
Concrete Pump	1	2	0.07	0.4	0.43	0.00	0.03	0.003
Concrete Saw	1	2	0.06	0.41	0.80	0.00	0.04	0.02
Crane (140 ton, composite hp)	2	10	0.06	0.41	0.80	0.00	0.04	0.04
Crane - Rough Terrane (28 ton, 120 hp)	0	0	0.07	0.4	0.42	0.00	0.02	0.02
Forklift	1	3	0.02	0.22	0.19	0.00	0.01	0.01
Generator	2	8	0.05	0.28	0.41	0.00	0.22	0.02
Plate Compactor	1	4	0.01	0.03	0.03	0.00	0.00	0.001
Welder	2	8	0.04	0.19	0.21	0.00	0.02	0.01

FCCU with SCR lbs/day = number *hrs/day*emission factor

Off- Road Equipment Type	ROG lbs/day	CO lbs/day	NOx lbs/day	SOx lbs/day	PM10 lbs/day	PM2.5 lbs/day	CO2 eq MT/d
Aerial Lift (Man Lift)	0.00	0.34	0.20	0.00	0.00	0.00	0.02
Air Compressor	0.06	0.32	0.43	0.00	0.03	0.0276	0.02
Backhoe	0.12	1.44	1.24	0.00	0.08	0.0736	0.08
Concrete Pump	0.02	0.8	0.86	0.00	0.06	0.0552	0.006
Concrete Saw	0.12	0.82	1.6	0.00	0.08	0.0736	0.04
Crane (140 ton, composite hp)	0	0	0	0.00	0	0	0.8
Forklift	0.06	0.66	0.57	0.00	0.03	0.0276	0.03
Generator	0.8	4.48	6.56	0.00	3.52	3.2384	0.32
Plate Compactor	0.04	0.12	0.12	0.00	0.00	0.00	0.004
Welder	0.64	3.04	3.36	0	0.32	0.2944	0.16
Subtotal lbs/day off-road	1.86	12.02	14.94	0.00	4.12	3.79	1.48

~~FCCU with SCR lbs/day and Tons/period~~

	~~ROG~~	~~CO~~	~~Nox~~	~~SOx~~	~~PM10~~	~~PM2.5 lbs/day~~	~~CO2eq MT~~
~~Subtotal Construction Worker Vehicle Emissions Trips #/day~~	~~4.96~~	~~7.46~~	~~0.69~~	~~0.69~~	~~0.32~~	~~0.13~~	~~0.96~~
~~Subtotal Const. worker Vehicle Trips tons/period~~	~~0.48~~	~~0.73~~	~~0.07~~	~~0.067~~	~~0.03~~	~~0.03~~	~~186.48~~
~~Heavy-heavy-duty Truck #/day~~	~~0.26~~	~~1.12~~	~~7.91~~	~~0.020~~	~~0.16~~	~~0.09~~	~~0.99~~
~~Heavy-heavy-duty Truck tons/period~~	~~0.03~~	~~0.11~~	~~0.77~~	~~0.002~~	~~0.02~~	~~0.01~~	~~192.53~~
~~Auto +HHD Truck lb/day~~	~~5.22~~	~~8.58~~	~~8.60~~	~~0.71~~	~~0.47~~	~~0.22~~	~~1.94~~
~~Subtotal Off-road #/day~~	~~1.86~~	~~12.02~~	~~14.94~~	~~0.711~~	~~4.12~~	~~3.79~~	~~1.50~~
~~Total #/day~~	~~7.08~~	~~20.60~~	~~23.54~~	~~1.42~~	~~4.59~~	~~4.01~~	~~3.44~~
~~Auto +HHD Truck tons/period~~	~~0.51~~	~~2.01~~	~~2.29~~	~~0.07~~	~~0.45~~	~~0.39~~	~~379.01~~
~~Subtotal Off-road tons/period~~	~~0.18~~	~~1.17~~	~~1.46~~	~~0~~	~~0.40~~	~~0.37~~	~~195.00~~
~~Total #/ period~~	~~7.08~~	~~20.60~~	~~23.54~~	~~1.42~~	~~4.59~~	~~4.01~~	
~~Total 1 SCR Tons per Constructionn period~~	~~0.69~~	~~3.18~~	~~3.75~~	~~0.07~~	~~0.85~~	~~0.76~~	~~574.01~~
~~Total 3 SCRs Tons per Construction period~~	~~2.07~~	~~9.54~~	~~11.25~~	~~0.21~~	~~2.55~~	~~2.28~~	~~1722.02~~

		~~Avg. Trip Length~~
~~Control equipment~~	~~# Auto Trips~~	~~One-way Trip~~
~~SCR FCCU~~	~~280~~	~~11~~
~~HHD trip length~~	~~HHD Truck trips/day~~	
~~50~~	~~10~~	

~~# of days =~~	~~130~~	~~total days 260~~

~~Ton/construction period = Total pounds/day*(Total days/construction period * 0.5) + (Total pounds/day * 0.5) * (Total days/construction period * 0.5)~~

FCCU with SCR lbs/day and Tons/period

	ROG	CO	Nox	SOx	PM10	PM2.5 lbs/day	CO2eq MT
Subtotal Construction Worker Vehicle Emissions Trips #/day	4.96	7.46	0.69	0.69	0.32	0.13	0.96
Subtotal Const. worker Vehicle Trips tons/period	0.48	0.73	0.07	0.067	0.03	0.03	186.48
Heavy-heavy-duty Truck #/day	0.26	1.12	7.91	0.020	0.16	0.09	0.99
Heavy-heavy-duty Truck tons/period	0.03	0.11	0.77	0.002	0.02	0.01	192.53
Auto +HHD Truck lb/day	5.22	8.58	8.60	0.71	0.47	0.22	1.94
Subtotal Off-road #/day	1.86	12.02	14.94	0.00	4.12	3.79	1.48
Total #/day	7.08	20.60	23.54	0.71	4.59	4.01	3.42
Auto +HHD Truck tons/period	0.51	0.84	0.84	0.07	0.05	0.04	379.01
Subtotal Off-road tons/period	0.18	1.17	1.46	0.00	0.40	0.37	288.60
Total #/ period	1379.93	4016.39	4589.40	138.21	895.65	817.82	667.61
Total 1 SCR Tons per Constructionn period	0.69	2.01	2.29	0.07	0.45	0.41	667.61
Total 3 SCRs Tons per Construction period	2.07	6.02	6.88	0.21	1.34	1.23	2002.82

Ton/construction period = Total pounds/day*(Total days/construction period * 0.5) + (Total pounds/day * 0.5) * (Total days/construction period * 0.5)

		Avg. Trip Length
Control equipment	# Auto Trips	One-way Trip
SCR FCCU	280	11
HHD trip length	HHD Truck trips/day	
50	10	

# of days =	130	total days 260

~~Carbon Adsorber Parameters~~

~~Off- Road Equipment Type~~	~~Number~~	~~Daily Hours of Use~~	~~ROG lbs/hr~~	~~CO lbs/hr~~	~~NOx lbs/hr~~	~~SOx lbs/hr~~	~~PM lbs/hr~~	~~CO2 eq MT/hr~~
~~Backhoe~~	~~1~~	~~4~~	~~0.07~~	~~0.4~~	~~0.42~~	~~0~~	~~0.02~~	~~0.02~~
~~Crane - Rough Terrane (28 ton, 120 hp)~~	~~1~~	~~8~~	~~0.04~~	~~0.19~~	~~0.21~~	~~0~~	~~0.02~~	~~0.02~~
~~Welder~~	~~2~~	~~8~~	~~0.06~~	~~0.06~~	~~0.32~~	~~0.43~~	~~0~~	~~0.01~~
~~Air Compressor~~	~~1~~	~~4~~	~~0.03~~	~~0.36~~	~~0.31~~	~~0~~	~~0.02~~	~~0.02~~
~~Plate Compactor~~	~~1~~	~~4~~	~~0.01~~	~~0.03~~	~~0.03~~	~~0~~	~~0~~	~~0.001~~
~~Forklift~~	~~1~~	~~3~~	~~0.02~~	~~0.22~~	~~0.19~~	~~0~~	~~0.01~~	~~0.01~~
~~Concrete Pump~~	~~1~~	~~2~~	~~0.01~~	~~0.04~~	~~0.05~~	~~0~~	~~0~~	~~0.003~~
~~Concrete Saw~~	~~1~~	~~2~~	~~0.07~~	~~0.4~~	~~0.43~~	~~0~~	~~0.03~~	~~0.02~~
~~Generator~~	~~1~~	~~8~~	~~0.05~~	~~0.28~~	~~0.41~~	~~0~~	~~0.22~~	~~0.02~~
~~Aerial Man Lift~~	~~1~~	~~2~~	~~0~~	~~0.17~~	~~0.1~~	~~0~~	~~0~~	~~0.01~~

~~Carbon Adsorber lbs/day = number *hrs/day*emission factor~~

~~Off- Road Equipment Type~~	~~ROG lbs/day~~	~~CO lbs/day~~	~~NOx lbs/day~~	~~SOx lbs/day~~	~~PM10 lbs/day~~	~~PM2.5 lbs/day~~	~~CO2 eq MT/d~~
~~Backhoe~~	~~0.28~~	~~1.6~~	~~1.68~~	~~0~~	~~0.08~~	~~0.074~~	~~0.08~~
~~Crane - Rough Terrane (28 ton, 120 hp)~~	~~0.32~~	~~1.52~~	~~1.68~~	~~0~~	~~0.16~~	~~0.15~~	~~0.16~~
~~Welder~~	~~0.96~~	~~0.96~~	~~5.12~~	~~0~~	~~0~~	~~0.00~~	~~0.16~~
~~Air Compressor~~	~~0.12~~	~~1.44~~	~~1.24~~	~~0~~	~~0.08~~	~~0.07~~	~~0.08~~
~~Plate Compactor~~	~~0.04~~	~~0.12~~	~~0.12~~	~~0~~	~~0~~	~~0.00~~	~~0.004~~
~~Forklift~~	~~0.06~~	~~0.66~~	~~0.57~~	~~0~~	~~0.00~~	~~0.00~~	~~0.03~~
~~Concrete Pump~~	~~0.02~~	~~0.08~~	~~0.1~~	~~0~~	~~0.00~~	~~0.00~~	~~0.006~~
~~Concrete Saw~~	~~0.14~~	~~0.8~~	~~0.86~~	~~0~~	~~0.06~~	~~0.06~~	~~0.04~~
~~Generator~~	~~0.4~~	~~2.24~~	~~3.28~~	~~0~~	~~1.76~~	~~1.62~~	~~0.16~~
~~Aerial Man Lift~~	~~0~~	~~0.34~~	~~0.2~~	~~0~~	~~0~~	~~0.00~~	~~0.02~~
~~Subtotal lbs/day off-road~~	~~2.34~~	~~9.76~~	~~14.85~~	~~0~~	~~2.14~~	~~1.97~~	~~0.74~~

	~~ROG lbs/day~~	~~CO lbs/day~~	~~NOx lbs/day~~	~~SOx lbs/day~~	~~PM10 lbs/day~~	~~PM2.5 lbs/day~~	~~CO2 eq MT~~
~~Construction worker vehicle emissions #/day~~	~~0.71~~	~~1.07~~	~~0.10~~	~~0.00~~	~~0.05~~	~~0.02~~	~~0.137~~
~~Heavy-heavy-duty Truck #/day~~	~~0.22~~	~~0.02~~	~~1.58~~	~~0.00~~	~~0.03~~	~~0.02~~	~~0.644~~
~~Subtotal Auto + HHD Truck #/day~~	~~0.93~~	~~1.08~~	~~1.68~~	~~0.01~~	~~0.08~~	~~0.04~~	~~0.781~~
~~Subtotal off-road #/day~~	~~2.34~~	~~9.76~~	~~14.85~~	~~0.00~~	~~2.14~~	~~1.97~~	~~0.740~~
~~Total #/day~~	~~3.27~~	~~10.84~~	~~16.53~~	~~0.01~~	~~2.22~~	~~2.01~~	~~1.521~~
~~Auto & HHD Truck tons/period~~	~~0.05~~	~~0.05~~	~~0.08~~	~~0.000~~	~~0.004~~	~~0.002~~	~~76.148~~
~~Off-road tons/period~~	~~0.11~~	~~0.48~~	~~0.72~~	~~0.00~~	~~0.10~~	~~0.10~~	~~72.150~~
~~Total 1 Unit tons/ period~~	~~0.16~~	~~0.53~~	~~0.81~~	~~0.00~~	~~0.11~~	~~0.10~~	~~148.3~~
~~Total 5 Units tons/period~~	~~0.80~~	~~2.64~~	~~4.03~~	~~0.00~~	~~0.54~~	~~0.49~~	~~741.5~~

		~~Avg. Trip Length~~
	~~# Vehicle Trips/day~~	~~One-way Trip~~
~~Worker trips~~	~~40~~	~~11~~
~~HHD truck trips/day~~	~~2~~	~~50~~

~~1/2 # of days =~~ ~~65~~ ~~Total 130~~

Carbon Adsorber Parameters

Off- Road Equipment Type	Number	Daily Hours of Use	ROG lbs/hr	CO lbs/hr	NOx lbs/hr	SOx lbs/hr	PM lbs/hr	CO2 eq MT/hr
Backhoe	1	4	0.07	0.4	0.42	0	0.02	0.02
Crane - Rough Terrane (28 ton, 120 hp)	1	8	0.04	0.19	0.21	0	0.02	0.02
Welder	2	8	0.06	0.06	0.32	0.43	0	0.01
Air Compressor	1	4	0.03	0.36	0.31	0	0.02	0.02
Plate Compactor	1	4	0.01	0.03	0.03	0	0	0.001
Forklift	1	3	0.02	0.22	0.19	0	0.01	0.01
Concrete Pump	1	2	0.01	0.04	0.05	0	0	0.003
Concrete Saw	1	2	0.07	0.4	0.43	0	0.03	0.02
Generator	1	8	0.05	0.28	0.41	0	0.22	0.02
Aerial Man Lift	1	2	0	0.17	0.1	0	0	0.01

Carbon Adsorber lbs/day = number *hrs/day*emission factor

Off- Road Equipment Type	ROG lbs/day	CO lbs/day	NOx lbs/day	SOx lbs/day	PM10 lbs/day	PM2.5 lbs/day	CO2 eq MT/d
Backhoe	0.28	1.6	1.68	0	0.08	0.074	0.08
Crane - Rough Terrane (28 ton, 120 hp)	0.32	1.52	1.68	0	0.16	0.15	0.16
Welder	0.96	0.96	5.12	0	0	0.00	0.16
Air Compressor	0.12	1.44	1.24	0	0.08	0.07	0.08
Plate Compactor	0.04	0.12	0.12	0	0	0.00	0.004
Forklift	0.06	0.66	0.57	0	0.00	0.00	0.03
Concrete Pump	0.02	0.08	0.1	0	0.00	0.00	0.006
Concrete Saw	0.14	0.8	0.86	0	0.06	0.06	0.04
Generator	0.4	2.24	3.28	0	1.76	1.62	0.16
Aerial Man Lift	0	0.34	0.2	0	0	0.00	0.02
Subtotal lbs/day off-road	2.34	9.76	14.85	0	2.14	1.97	0.74

	ROG lbs/day	CO lbs/day	NOx lbs/day	SOx lbs/day	PM10 lbs/day	PM2.5 lbs/day	CO2 eq MT
Construction worker vehicle emissions #/day	0.71	1.07	0.10	0.00	0.05	0.02	0.137
Heavy-heavy-duty Truck #/day	0.22	0.02	1.58	0.00	0.03	0.02	0.644
Subtotal Auto + HHD Truck #/day	0.93	1.08	1.68	0.01	0.08	0.04	0.781
Subtotal off-road #/day	2.34	9.76	14.85	0.00	2.14	1.97	0.74
Total #/day	3.27	10.84	16.53	0.01	2.22	2.01	1.52
Auto & HHD Truck tons/period	0.05	0.05	0.08	0.000	0.004	0.002	76.148
Off-road tons/period	0.11	0.48	0.72	0.00	0.10	0.10	72.150
Total 1 Unit tons/ period	0.16	0.53	0.81	0.00	0.11	0.10	148.3
Total 5 Units tons/period	0.80	2.64	4.03	0.00	0.54	0.49	741.5

	# Vehicle Trips/day	Avg. Trip Length One-way Trip
Worker trips	40	11
HHD truck trips/day	2	50

1/2 # of days = 65 Total 130

~~On-road Mobile Source Emission Factors~~

~~Light-duty Auto~~	~~CO~~	~~ROG~~	~~Nox~~	~~SOx~~	~~PM10~~	~~PM2.5~~	~~CO2~~	
~~Break-wear g/mile = (a)~~					~~0.036750011~~	~~0.015750005~~		
~~Tire wear g/mile = (b)~~					~~0.008000002~~	~~0.002000001~~		
~~Running Evaporation g/mile = (c)~~		~~0.32685~~						
~~Running Exhaust g/mile = (d)~~	~~0.88207051~~	~~0.0206274~~	~~0.08658368~~	~~0.00305211~~	~~0.00173145~~	~~0.001593313~~	~~304.297585~~	~~exhaust~~
~~Start-up g/trip = (e)~~	~~2.386995467~~	~~4.215288~~	~~0.16371717~~	~~0.00072322~~	~~0.002529158~~	~~0.002328798~~	~~68.1117653~~	~~startup~~

~~Equation: (No. of One-way Vehicles Trips*One-way Trip Length*[(a) PM10/PM2.5 only]*[(b) PM10/PM2.5 only]*[(c) ROG only]}/(lb/454gm))+((Number of One-way Vehicle trips*(e))/(lb/454gm)~~

~~Star-up includes startu-up exhaust + hotsoak+running loss+((restng loss+diurnal)/2)~~

~~Heavy-Heavy-Duty Truck Mobile Source Emission Factors~~

~~Heavy-Heavy-Duty Truck (diesel)~~	~~CO~~	~~ROG~~	~~Nox~~	~~SOx~~	~~PM10~~	~~PM2.5~~	~~CO2~~
~~Break-wear g/mile = (g)~~					~~0.061~~	~~0.026~~	
~~Tire wear g/mile = (h)~~					~~0.035~~	~~0.009~~	
~~Running Exhaust g/mile (i)~~	~~0.839~~	~~0.192~~	~~5.802~~	~~0.016~~	~~0.043~~	~~0.041~~	~~1739.42788~~
~~Idling Exhaust g/vehicle/day = (j)~~	~~8.907~~	~~2.327~~	~~68.888~~	~~0.110~~	~~0.140~~	~~0.134~~	~~11761.0534~~

~~Equation: (No. of One-way Vehicles Trips*One-way Trip Length*[(g) PM10/PM2.5 only]*[(h) PM10/PM2.5 only]}/(lb/454gm))+((Number of One-way Vehicle trips*(j))/(lb/454gm)~~

~~Reference: CARB, EMFAC 2014 for the Bay Area~~

On-road Mobile Source Emission Factors

Light-duty Auto	CO	ROG	Nox	SOx	PM10	PM2.5	CO2	
Break-wear g/mile = (a)					0.036750011	0.015750005		
Tire wear g/mile = (b)					0.008000002	0.002000001		
Running Evaporation g/mile = (c)		0.32685						
Running Exhaust g/mile = (d)	0.88207051	0.0206274	0.08658368	0.00305211	0.00173145	0.001593313	304.297585	exhaust
Start-up g/trip = (e)	2.386995467	4.215288	0.16371717	0.00072322	0.002529158	0.002328798	68.1117653	startup

Equation: (No. of One-way Vehicles Trips*One-way Trip Length*[(a) PM10/PM2.5 only]*[(b) PM10/PM2.5 only]*[(c) ROG only])/(lb/454gm))+((Number of One-way Vehicle trips*(e))/(lb/454gm)

Star-up includes startu-up exhaust + hotsoak+running loss+((restng loss+diurnal)/2)

Heavy-Heavy-Duty Truck Mobile Source Emission Factors

Heavy-Heavy-Duty Truck (diesel)	CO	ROG	Nox	SOx	PM10	PM2.5	CO2
Break-wear g/mile = (g)					0.061	0.026	
Tire wear g/mile = (h)					0.035	0.009	
Running Exhaust g/mile (i)	0.839	0.192	5.802	0.016	0.043	0.041	1739.42788
Idling Exhaust g/vehicle/day = (j)	8.907	2.327	68.888	0.110	0.140	0.134	11761.0534

Equation: (No. of One-way Vehicles Trips*One-way Trip Length*[(g) PM10/PM2.5 only]*[(h) PM10/PM2.5 only])/(lb/454gm))+((Number of One-way Vehicle trips*(j))/(lb/454gm)

Reference: CARB, EMFAC 2014 for the Bay Area

~~NaOH HRA~~

	~~Daily Usage Tons/Day~~	~~Annual Usage Tons/year~~	~~Usage Rate gal/hr~~	~~Density #/gal~~	~~#/hr~~
~~NaOH (50% solution)~~	~~3.37~~	~~1228.30~~	~~22.00~~	~~12.747~~	~~280.43~~

~~NaOH Demand Filling Loss (lb/day)~~	~~Q = Fill Rate = NaOH Demand (MMgal/day)~~	~~S = Saturation Factor~~	~~P = Vapor Pressure of material Loaded (psia)~~	~~M = NaOH vapor molecular weight (lb/lbmole)~~	~~T= temperature of liquid loaded (oR)~~	~~Daily PM10 Filling Loss (lb/day)~~	~~Eworking = Hourly PM10 Working Loss (lb/hr)~~	~~Total Hourly PM10 Loss (lb/hr)~~	~~Total Hourly PM10 Loss (lb/hr) at 25m~~
~~3.37~~	~~0.53~~	~~1.45~~	~~0.042~~	~~24.8~~	~~544.67~~	~~1.82E-02~~	~~7.60E-04~~	~~2.28E-03~~	~~2.28E-05~~

~~NaOH @ 50% solution density = 12.747 lb/gal~~
~~Mv for NaOH solution = 24.8 lb/lbmol~~
~~Vapor Pressure for NaOH = 2.18 mmHg at 29.4oC or 85oF = 0.042 psia~~
~~Loading Temperature = 85°F to 100°F (544.67°R to 559.67°R)~~
~~Breathing Loss = 3 * Filling Loss~~

~~Filling Loss~~

~~$E_{loading}$ lb/day = (12.46) ((S)(P)(M)(Q))/T where:~~

~~S = saturation factor (dimensionless; obtained from Table 5.2-1 in AP-42)~~
~~= 1.45 (Splash loading: dedicated normal service)~~
~~P = vapor pressure of the material loaded at temperature T (psia)~~
~~M = vapor molecular weight (lb/lb-mole)~~
~~Q = volume of material loaded (1,000 gal/day)~~
~~T = temperature of liquid loaded (°R).~~

~~Caustic/NaOH & Ammonia Delivery Truck Trips~~

~~Caustic/NaOH~~	~~VOC lbs/day~~	~~CO lbs/day~~	~~NOx lbs/day~~	~~SOx lbs/day~~	~~PM10 lbs/day~~	~~PM2.5 lbs/day~~	~~CO2 MT/day~~
~~Subtotal 1 HHD/day #/day~~	~~0.06~~	~~0.26~~	~~1.84~~	~~0.02~~	~~0.31~~	~~0.02~~	~~0.23~~
~~Total 10 HHD Truck/day #/day~~	~~0.61~~	~~2.61~~	~~18.37~~	~~0.19~~	~~3.08~~	~~0.21~~	~~2.32~~
~~Subtotal 1 Facility Tons/year~~	~~0.032~~	~~0.14~~	~~0.96~~	~~0.00~~	~~0.160~~	~~0.011~~	~~24.15~~
~~Total 5 Facilities Tons/year~~	~~0.16~~	~~0.68~~	~~4.78~~	~~0.005~~	~~0.802~~	~~0.054~~	~~120.772~~
~~Ammonia~~							
~~Subtotal 1 HHD/day #/day~~	~~0.05~~	~~0.22~~	~~1.58~~	~~0.004~~	~~0.031~~	~~0.017~~	~~0.20~~
~~Total 6 HHD Truck/day #/day~~	~~0.32~~	~~1.34~~	~~9.49~~	~~0.024~~	~~0.187~~	~~0.104~~	~~1.18~~
~~Subtotal 1 Facility Tons/year~~	~~0.00~~	~~0.01~~	~~0.06~~	~~0.00~~	~~0.00~~	~~0.00~~	~~15.80~~
~~Total 3 Facilities Tons/year~~	~~0.01~~	~~0.03~~	~~0.19~~	~~0.00~~	~~0.00~~	~~0.00~~	~~47.39~~

	~~# One- Trips/day HHD Truck~~	~~Avg. Trip Length One way HHD Truck~~	~~Trips per Year~~
~~Caustic~~	~~10~~	~~60~~	~~104~~
~~Ammonia~~	~~6~~	~~50~~	~~80~~
~~1 Caustic~~	~~2~~		
~~1 NH3~~	~~2~~		

~~Heavy-Heavy-Duty Truck Mobile Source Emission Factors~~

~~Heavy-Heavy-Duty Truck (diesel)~~	~~CO~~	~~ROG~~	~~Nox~~	~~SOx~~	~~PM10~~	~~PM2.5~~	~~CO2~~
~~Break-wear g/mile = (g)~~					~~0.061~~	~~0.026~~	
~~Tire wear g/mile = (h)~~					~~0.035~~	~~0.009~~	
~~Running Exhaust g/mile (i)~~	~~0.839~~	~~0.192~~	~~5.802~~	~~0.016~~	~~0.043~~	~~0.041~~	~~1739.427878~~
~~Idling Exhaust g/vehicle/day = (j)~~	~~8.907~~	~~2.327~~	~~68.888~~	~~0.110~~	~~0.140~~	~~0.134~~	~~11761.05342~~

~~Equation: (No. of One-way Vehicles Trips*One-way Trip Length*[(g) PM10/PM2.5 only]*[(h) PM10/PM2.5 only])/(lb/454gm))+((Number of One-way Vehicle trips*(j))/(lb/454gm)~~
~~Reference: CARB, EMFAC 2014 for the Bay Area~~

~~Operational GHG Emissions from Regerating Spent Carbon~~

~~Fuel type~~	~~Natural Gas Usage scfmm/day~~	~~CH4 lb/mmscf~~	~~N2O lb/mmscf~~	~~CO2 lb/mmscf~~	~~Regeneration D/yr~~
~~Natural Gas~~	~~0.062~~	~~2.3~~	~~0.64~~	~~120000~~	~~365~~

~~Natural Gas Usage mmscf/yr~~	~~22.63~~	~~CH4 MT/yr~~	~~NO2 MT/yr~~	~~CO2 MT/year~~	~~CO2e MT/year~~
~~1 Unit~~		~~0.02~~	~~0.01~~	~~1231.56~~	~~1234.32~~
~~5 Units~~		~~0.12~~	~~0.03~~	~~6157.82~~	~~6171.62~~

	~~GWP factors~~
~~CO2 =~~	~~1~~
~~CH4 =~~	~~34~~
~~N2O =~~	~~298~~

NaOH HRA

	Daily Usage Tons/Day	Annual Usage Tons/year	Usage Rate gal/hr	Density #/gal	#/hr
NaOH (50% solution)	3.37	1228.30	22.00	12.747	280.43

NaOH Demand Filling Loss (lb/day)	Q = Fill Rate = NaOH Demand (MMgal/day)	S = Saturation Factor	P = Vapor Pressure of material Loaded (psia)	M = NaOH vapor molecular weight (lb/lbmole)	T= temperature of liquid loaded (oR)	Daily PM10 Filling Loss (lb/day)	Eworking = Hourly PM10 Working Loss (lb/hr)	Total Hourly PM10 Loss (lb/hr)	Total Hourly PM10 Loss (lb/hr) at 25m
3.37	0.53	1.45	0.042	24.8	544.67	1.82E-02	7.60E-04	2.28E-03	2.28E-05

NaOH @ 50% solution density = 12.747 lb/gal
Mv for NaOH solution = 24.8 lb/lbmol
Vapor Pressure for NaOH = 2.18 mmHg at 29.4oC or 85oF = 0.042 psia
Loading Temperature = 85^{o}F to 100^{o}F (544.67^{o}R to 559.67^{o}R)
Breathing Loss = 3 * Filling Loss

Filling Loss

$E_{loading}$ lb/day = (12.46) ((S)(P)(M)(Q))/T where

S = saturation factor (dimensionless; obtained from Table 5.2-1 in AP-42)
= 1.45 (Splash loading: dedicated normal service)
P = vapor pressure of the material loaded at temperature T (psia)
M = vapor molecular weight (lb/lb-mole)
Q = volume of material loaded (1,000 gal/day)
T = temperature of liquid loaded (^{o}R).

Caustic/NaOH & Ammonia Delivery Truck Trips

Caustic/NaOH	VOC lbs/day	CO lbs/day	NOx lbs/day	SOx lbs/day	PM10 lbs/day	PM2.5 lbs/day	CO2 MT/day
Subtotal 1 HHD/day #/day	0.06	0.26	1.84	0.02	0.04	0.02	0.23
Total 10 HHD Truck/day #/day	0.61	2.61	18.37	0.19	0.37	0.21	2.32
Subtotal 1 Facility Tons/year	0.003	0.01	0.10	0.00	0.002	0.001	24.15
Total 5 Facilities Tons/year	0.02	0.07	0.48	0.005	0.010	0.005	120.772
Ammonia							
Subtotal 1 HHD/day #/day	0.05	0.22	1.58	0.004	0.031	0.017	0.20
Total 6 HHD Truck/day #/day	0.32	1.34	9.49	0.024	0.187	0.104	1.18
Subtotal 1 Facility Tons/year	0.00	0.01	0.06	0.00	0.00	0.00	15.80
Total 3 Facilities Tons/year	0.01	0.03	0.19	0.00	0.00	0.00	47.39

	# One- Trips/day	Avg. Trip Length One way	
	HHD Truck	HHD Truck	Trips per Year
Caustic	10	60	104
Ammonia	6	50	80
1 Caustic	2		
1 NH3	2		

Heavy-Heavy-Duty Truck Mobile Source Emission Factors

Heavy-Heavy-Duty Truck (diesel)	CO	ROG	Nox	SOx	PM10	PM2.5	CO2
Break-wear g/mile = (g)					0.061	0.026	
Tire wear g/mile = (h)					0.035	0.009	
Running Exhaust g/mile (i)	0.839	0.192	5.802	0.016	0.043	0.041	1739.427878
Idling Exhaust g/vehicle/day = (j)	8.907	2.327	68.888	0.110	0.140	0.134	11761.05342

Equation: (No. of One-way Vehicles Trips*One-way Trip Length*[(g) PM10/PM2.5 only]*[(h) PM10/PM2.5 only])/(lb/454gm))+((Number of One-way Vehicle trips*(j))/(lb/454gm)
Reference: CARB, EMFAC 2014 for the Bay Area

Operational GHG Emissions from Regerating Spent Carbon

Fuel type	Natural Gas Usage scfmm/regen	CH4 lb/mmscf	N2O lb/mmscf	CO2 lb/mmscf	Regeneration per year
Natural Gas	0.0022	2.3	0.64	120000	12

Natural Gas Usage mmscf/yr	22.63	CH4 MT/yr	NO2 MT/yr	CO2 MT/year	CO2e MT/year
1 Unit		0.00	0.00	1.44	1.44
5 Units		0.00	0.00	7.18	7.20

The amount of natural gas required per year is estimated to be 0.0264 million cubic feet (MMcf) [(400 lbs C) x (5.5 scf/lb C per regen) x (12 regen/yr) = 26,400 cf/yr].

	GWP factors
CO2 =	1
CH4 =	34
N2O =	298

APPENDIX A

NOTICE OF PREPARATION AND INITIAL STUDY

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BAY AREA
AIR QUALITY
MANAGEMENT
DISTRICT

California Environmental Quality Act

Notice of Preparation of Draft Environmental Impact Report for Regulation 11: Hazardous Pollutants, Rule 18: Reduction of Risk from Air Toxic Emissions at Existing Facilities (Rule 11-18) and Regulation 12: Miscellaneous Standards of Performance, Rule 16: Petroleum Refining Facility-Wide Emissions Limits (Rule 12-16).

Lead Agency: **Bay Area Air Quality Management District**
Contact: **Greg Nudd** **Phone: (415) 749-4786**

SUBJECT: NOTICE OF PREPARATION OF A DRAFT ENVIRONMENTAL IMPACT REPORT

Notice is hereby given pursuant to California Public Resources Code §21091, 21092, 21092.2, and 21092.3 and CEQA Guidelines Section 15085 and 15087 that the Bay Area Air Quality Management District ("Air District"), as lead agency, will prepare a Draft Environmental Impact Report (EIR) in connection with the projects described below.

Project Title: Air District Regulation 11: Hazardous Pollutants, Rule 18: Reduction of Risk from Air Toxic Emissions at Existing Facilities (Rule 11-18) and Regulation 12: Miscellaneous Standards of Performance, Rule 16: Petroleum Refining Facility-Wide Emissions Limits (Rule 12-16).

Project Location: The rules would apply within the Bay Area Air Quality Management District ("District"), which includes all of Alameda, Contra Costa, Marin, Napa, San Francisco, San Mateo, and Santa Clara counties, and the southern portions of Solano and Sonoma counties.

Project Description: Rule 11-18 would ensure that emissions of toxic air contaminants (TACs) from existing facilities do not pose an unacceptable health risk to people living and working nearby. The rule would use the most up-to-date assumptions about the risk of compounds and would require affected facilities to take action to reduce risk to a low level.

Rule 12-16 would limit the emissions of climate pollutants: greenhouse gases (GHGs); and three criteria pollutants: particulate matter (PM), oxides of nitrogen (NOx), and sulfur dioxide (SO_2) from the five Bay Area petroleum refineries and three associated facilities. The rule would establish facility-wide emissions limits for the covered pollutants at each of the affected facilities to ensure there is no emissions increase due to changes in operation, crude or product slates, or increases in production.

Scoping Meetings: Notice is also given pursuant to California Public Resource Code, Sections 15206 and 15082 (c) that the Air District will conduct California Environmental Quality Act (CEQA) scoping meetings at the Air District Headquarters' Yerba Buena Room, 375 Beale Street, San Francisco, California, on November 14, 2016 at 2:00 p.m. and at the Martinez City Hall, 525 Henrietta Street, Martinez, California, on November 16, 2016 at 2:00 p.m. to discuss and accept oral comments on the scope and content described in a Notice of Preparation and an Initial Study (NOP/IS) prepared in anticipation of a draft Environmental Impact Report (DEIR) that would be prepared for two new proposed rules.

Reviewing the Notice of Preparation/Initial Study (NOP/IS): The NOP/IS are available at the District headquarters or on the Air District's website at http://www.baaqmd.gov/rules-and-compliance/rule-development/regulatory-workshops or by request. Requests for copies of the NOP/IS should be directed to Jocelyn Orpia (jorpia@baaqmd.gov) at (415) 749-4763.

Comment Procedure: Comments relating to the environmental analysis in the NOP/IS should be addressed to Victor Douglas, Bay Area Air Quality Management District, 375 Beale Street, Suite 600, San Francisco, CA 94105. Comments may also be sent by e-mail to vdouglas@baaqmd.gov. Comments on the NOP/IS will be accepted from October 14, 2016 until December 2, 2016 at 5:00 p.m.

BAY AREA
AIR QUALITY
MANAGEMENT
DISTRICT

CEQA NOTICE OF PREPARATION OF A DRAFT ENVIRONMENTAL IMPACT REPORT

October 14, 2016

To: Interested Parties

From: Executive Officer/APCO

Subject: Notice of Preparation of a Draft Environmental Impact Report

Project Title: Air District Regulation 11: Hazardous Pollutants, Rule 18: Reduction of Risk from Air Toxic Emissions at Existing Facilities (Rule 11-18) and Regulation 12: Miscellaneous Standards of Performance, Rule 16: Petroleum Refining Facility-Wide Emissions Limits (Rule 12-16).

In accordance with the California Environmental Quality Act (CEQA) (California Code of Regulations, Title 14, Sections 15082(a)), the Bay Area Air Quality Management District (District) will be the Lead Agency for the project identified above and described in the attached Initial Study. Through this Notice of Preparation (NOP), the District is soliciting information and your views on the scope of the environmental analysis for the project. As detailed in the attached Initial Study, District staff has made a preliminary determination that the potential air quality, greenhouse gas, hazard, and hydrology/water quality impacts of the rules require more detailed analyses in an Environmental Impact Report (EIR).

Due to the time limits mandated by State law, your response must be sent at the earliest possible date but not later than 30 days after receipt of this notice. Comments focusing on your area of expertise, your agency's area of jurisdiction, or issues relative to the environmental analysis should be addressed to Mr. Victor Douglas at the address shown below, or by e-mail to vdouglas@baaqmd.gov. Comments must be received no later than 5:00 PM on December 2, 2016. Please include the name and phone number of the contact person for your agency. Questions relative to the proposed Rule amendments should be directed to Mr. Victor Douglas (415) 749-4752, or by email to vdouglas@baaqmd.gov.

The following CEQA scoping meetings are scheduled for the rules:

Air District Headquarters Yerba Buena Room 375 Beale Street San Francisco, California November 14, 2016 at 2:00 p.m.	Martinez City Hall 525 Henrietta Street Martinez, California November 16, 2016 at 2:00 p.m

Date: *October 14, 2016*

Signature:

Greg Nudd
Rule Development Manager

BAY AREA AIR QUALITY MANAGEMENT DISTRICT
375 Beale Street, Suite 600, San Francisco, California 94105

NOTICE OF PREPARATION OF A DRAFT ENVIRONMENTAL IMPACT REPORT

Project Title:
Air District Regulation 11: Hazardous Pollutants, Rule 18: Reduction of Risk from Air Toxic Emissions at Existing Facilities (Rule 11-18) and Regulation 12: Miscellaneous Standards of Performance, Rule 16: Petroleum Refining Facility-Wide Emissions Limits (Rule 12-16).

Project Location:
The rules would apply within the Bay Area Air Quality Management District ("District"), which includes all of Alameda, Contra Costa, Marin, Napa, San Francisco, San Mateo, and Santa Clara counties, and the southern portions of Solano and Sonoma counties.

Description of Nature, Purpose, and Beneficiaries of Project:
Rule 11-18 would ensure that emissions of toxic air contaminants (TACs) from existing facilities do not pose an unacceptable health risk to people living and working nearby. The rule would use the most up-to-date assumptions about the risk of compounds and would require affected facilities to take action to reduce risk to a low level.

Rule 12-16 would limit the emissions of climate pollutants: greenhouse gases (GHGs); and three criteria pollutants: particulate matter (PM), oxides of nitrogen (NOx), and sulfur dioxide (SO_2) from the five Bay Area petroleum refineries and three associated facilities. The rule would establish facility-wide emissions limits for the covered pollutants at each of the affected facilities to ensure there is no emissions increase due to changes in operation, crude or product slates, or increases in production.

Lead Agency:
Bay Area Air Quality Management District

Initial Study and all Supporting Documentation are Available at:

BAAQMD Headquarters 375 Beale Street, Suite 600 San Francisco, CA 94105	Or by Calling: (415) 749-4763

Attn: Jocelyn Orpia (jorpia@baaqmd.gov) at (415) 749-4763
Or by accessing: http://www.baaqmd.gov/rules-and-compliance/rule-development/regulatory-workshops

Scheduled Scoping Meeting Dates:

Air District Headquarters Yerba Buena Room 375 Beale Street San Francisco, California November 14, 2016 at 2:00 p.m.	Martinez City Hall 525 Henrietta Street Martinez, California November 16, 2016 at 2:00 p.m

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The Notice of Preparation is provided through the following:

☑ Office of Planning & Research, State Clearinghouse	☑ BAAQMD Website
☑ Newspaper	
☑ Interested Parties	☑ BAAQMD Mailing List

Review Period:
October 14, 2016 through December 2, 2016

Contact Person:	Phone Number:	E-Mail Address
Victor Douglas	(415) 749-4752	vdouglas@baaqmd.gov

BAY AREA AIR QUALITY MANAGEMENT DISTRICT

Initial Study for

Regulation 11, Rule 18: Reduction of Risk from Air Toxic Emissions at Existing Facilities
&
Regulation 12, Rule 16: Petroleum Refining Facility-Wide Emissions Limits

Prepared by:

Staff of the Bay Area Air Quality Management District
375 Beale Street, Suite 600
San Francisco, California 94105

Contact: Victor Douglas
415-749-4752

October 2016

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1.0 PROJECT DESCRIPTION

1.1 INTRODUCTION

Petroleum refineries are significant sources of harmful pollutants on both the global (greenhouse gases) and local scale (toxic air contaminants and criteria pollutants). Many Bay Area residents have expressed concern about the impact of this pollution on the environment and public health, particularly those that may disproportionately impact communities near refineries. Though refinery emissions have declined over time, it is possible that as refinery operations change in the future, emissions of these pollutants could increase.

In response to these concerns, the Board of Directors of the Bay Area Air Quality Management District (Air District) has directed staff to bring forward two rules for their consideration, one that reflects policy recommended by some environmental advocacy organizations, and an approach recommended by Air District staff.

Communities for a Better Environment (CBE) and several associated organizations (CBE) have recommended that the Air District adopt new Regulation 12, Rule 16: Petroleum Refining Facility-Wide Emissions Limits (Rule 12-16 or "Refining Caps Rule"). This rule would set numeric limits on specific refinery emissions. Rule 12-16 would apply only to the Bay Area's five petroleum refineries and three facilities associated with the refineries.

The staff of the Air District has developed a different approach that directly addresses concerns about health risks to communities exposed to air pollution. The staff recommendation is that the Air District adopt a new Regulation 11, Rule 18: Reduction of Risk from Air Toxic Emissions at Existing Facilities (Rule 11-18 or "Toxic Risk Reduction Rule"). Rule 11-18 would apply to all facilities whose emissions of toxic air contaminants may result in a significant risk to nearby residents and workers – this would include petroleum refineries. The purpose of Rule 11-18 is to reduce the public's exposure to health risks associated with the emissions of toxic air contaminants (TACs) from stationary sources by reducing those risks to the lowest feasible levels

Because the Board of Directors of the Air District intends to consider these rules within the same timeframe, staff is preparing one Environmental Impact Report (EIR) to cover both rules. The intent of the single EIR is to ensure that all of the potential environmental impacts for both rules are considered and comprehensively addressed. Although they are being considered at the same time and both would affect refineries, the two rules are functionally independent. Adoption of one does not depend on adoption of the other. The Board of Directors could adopt either rule, both rules or neither rule.

1.1.1 Rule 12-16 – Refinery Emissions Caps Rule

Rule 12-16 reflects a policy recommendation from CBE and their associated organizations (henceforth called "CBE"). The rule, as proposed by CBE, would limit the emissions of climate pollutants and three criteria pollutants: greenhouse gases (GHGs), particulate matter (PM), oxides of nitrogen (NOx), and sulfur dioxide (SO_2) from petroleum refineries and three associated facilities. The rule would establish facility-wide emissions limits for the covered pollutants at each of the affected facilities to ensure that each facility does not increase emissions due to changes in operation, crude or product slates, or increases in production. Each facility emissions limit would be set at the maximum-annual emissions reported for that facility in the period from 2011 through 2015[1] with an additional allowance or "threshold factor" of seven percent over the maximum annual emission rate for each pollutant.

1.1.2 Rule 11-18 – Toxic Risk Reduction Rule

Rule 11-18, as drafted by Air District staff, would ensure that emissions of toxic air contaminants (TACs) from existing facilities do not pose an unacceptable health risk to people living and working nearby. The rule would use the most up-to-date assumptions about the risk of compounds and would require the facility to take action to reduce risk below a specified risk threshold, if the facility exceeds the risk thresholds. If the facility could not devise a means to reduce the risk below the specified risk level, the facility would be required to install best available retrofit control technology for toxic pollutants (TBARCT) on every significant source of TAC emissions at the facility.

1.2 AGENCY AUTHORITY

The California Environmental Quality Act (CEQA), Public Resources Code §21000 et seq., requires that the environmental impacts of proposed projects be evaluated and that feasible methods to reduce, avoid or eliminate significant adverse impacts of these projects be identified and implemented. To fulfill the purpose and intent of CEQA, the Air District is the lead agency for Regulation 12, Rule 16 and Regulation 11, Rule 18 and has prepared this Notice of Preparation (NOP) of an Environmental Impact Report (EIR) and Initial Study (NOP/IS) to address the potential environmental impacts associated with the rules.

1.3 PROJECT LOCATION

The Air District has jurisdiction over an area encompassing 5,600 square miles. The Air District includes all of Alameda, Contra Costa, Marin, San Francisco, San Mateo, Santa Clara, and Napa Counties, and portions of southwestern Solano and southern Sonoma counties. The San Francisco Bay Area is characterized by a large, shallow basin surrounded by coastal mountain ranges tapering into sheltered inland valleys. The combined climatic and topographic factors result in increased potential for the accumulation of air pollutants in the inland valleys and reduced potential for buildup of air pollutants along the coast. The Basin is bounded by the Pacific Ocean to the west and includes complex terrain consisting of coastal mountain ranges, inland valleys and bays (see Figure 1-1).

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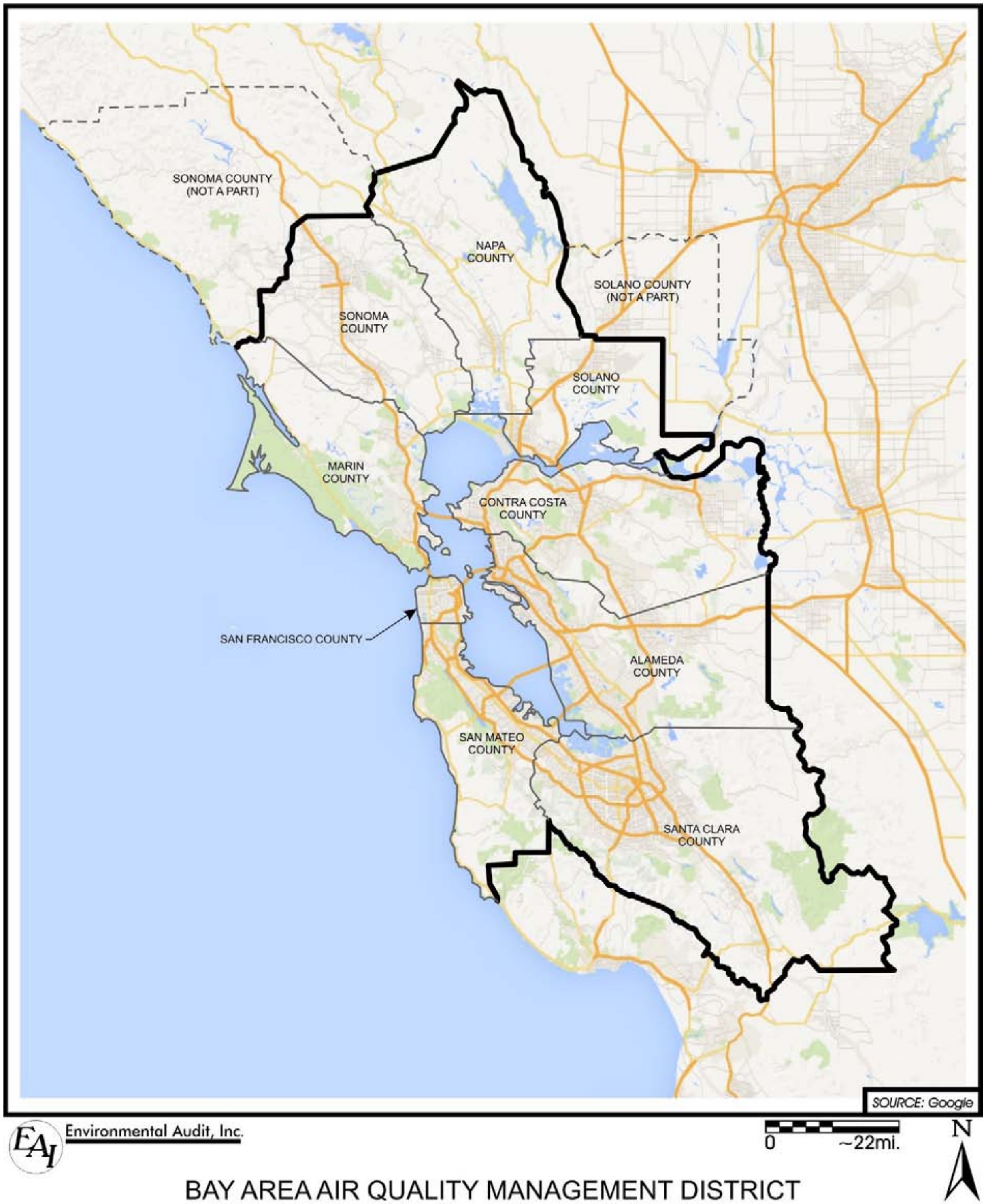
[1] GHG emissions are based on the 2011-2014 time period, since 2015 data is not available from the Air Resources Board yet.

Figure 1-1

Geographic Jurisdictional Boundaries of the Bay Area Air Quality Management District



1.4 BACKGROUND

Rule 12-16 would affect the five petroleum refineries currently located in the Bay Area within the jurisdiction of the Air District:

- Chevron Products Company (Richmond),
- Phillips 66 Company – San Francisco Refinery (Rodeo),
- Shell Martinez Refinery (Martinez),
- Tesoro Refining and Marketing Company (Martinez), and
- Valero Refining Company – California (Benicia).

The rule would also affect three refinery-related facilities:

- Air Liquide (Richmond),
- Air Products (Martinez), and
- Martinez Cogen LP (Martinez).

Rule 11-18 would affect hundreds of facilities that emit TACs. The Air District has determined that these toxic emissions need to be reduced in order to be more protective of public health. These facilities include data centers, petroleum refineries, a cement kiln, gasoline dispensing facilities, etc., and emit a variety of TACs that can adversely impact public health. TACs include compounds such as diesel particulate matter (DPM), benzene, polycyclic aromatic hydrocarbons (PAHs), and 1,3-butadiene.

The primary focus of CBE's concern has been petroleum refineries. Petroleum refineries convert crude oil into a wide variety of refined products, including gasoline, aviation fuel, diesel and other fuel oils, lubricating oils, and feed stocks for the petrochemical industry. Crude oil consists of a complex mixture of hydrocarbon compounds with smaller amounts of impurities including sulfur, nitrogen, oxygen and metals (e.g., iron, copper, nickel, and vanadium).

Air pollutants are categorized based on their properties, and the programs under which they are regulated. Air pollutants include: (1) criteria pollutants, (2) toxic pollutants (or TACs), and (3) climate pollutants (or GHGs). Additional categories of air contaminants include odorous compounds and visible emissions.

Criteria pollutants are emissions for which Ambient Air Quality Standards (AAQS) have been set and include: (1) carbon monoxide (CO), (2) nitrogen dioxide (NO_2) and NO_X, (3) PM in two size ranges – aerodynamic diameter of 10 micrometers or less (PM_{10}), and aerodynamic diameter of 2.5 micrometers or less ($PM_{2.5}$), (4) volatile organic compounds (VOC), and (5) sulfur dioxide (SO_2). Other compounds, specifically volatile organic compounds (VOC), can react in the atmosphere to form ozone and are often regulated along with criteria pollutants. These compounds can have both localized and regional impacts. Each of these criteria pollutants are emitted by petroleum refineries, as well as numerous other stationary sources and mobile sources (automobiles, trucks, locomotive engines, marine vessels, construction equipment, etc.).

TACs are emissions for which AAQS have generally not been established, but may result in human health risks. The state list of TACs currently includes approximately 190 separate chemical compounds and groups of compounds. These compounds tend to have more localized impacts. There are many TACs potentially emitted from industrial sources, including refineries.

GHGs are emissions that include carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), and three groups of fluorinated compounds (i.e., hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6)), and are the major anthropogenic GHGs. These compounds are global in nature and require a global reduction to a beneficial benefit on the global climate. GHGs emitted from petroleum refineries include CO_2, CH_4 and N_2O.

The regulatory approaches for Rules 11-18 and 12-16 are summarized below and include the following basic elements.

Regulation 11, Rule 18

- The Air District would screen all facilities that report toxic emissions. From this screening, the Air District would determine each facility's priority score (PS). The Air District would conduct health risk assessments (HRA) for facilities with a cancer risk prioritization score of 10 or greater or a non-cancer prioritization score of 1.0 or greater. The HRAs would incorporate the new Office of Environmental Health Hazard Assessment (OEHHA) protocol and health risk values adopted in March 2015, the Risk Management Guidelines adopted in July 2015 by the California Air Resources Board (ARB) and the California Air Pollution Control Officers Association (CAPCOA) and revised Air District HRA guidelines. The Air District will prioritize the development of the HRAs according to priority score and then according to type of facility. This is described in more detail later in this document.
- Facilities that pose a cancer risk in excess of 10 per million or a chronic or acute hazard index in excess of 1.0 must either:
  - Reduce the facility cancer risk below 10/M and reduce the chronic and acute hazard indices below 1.0; or
  - Install TBARCT on all significant sources of toxic emissions.

Regulation 12, Rule 16

- Would apply to each of the Bay Area petroleum refineries and three support facilities.
- Would establish facility-wide emissions limits for GHGs, $PM_{2.5}$ and PM_{10}, NOx, and SO_2 at each of the affected facilities based on the following method:
  - Each facility emissions limit would be set at the maximum-annual emissions reported for that facility in the period from 2011 through 2015,[2] and
  - Include an additional allowance or "threshold factor" that would equal seven percent over the maximum for GHGs, $PM_{2.5}$ and PM_{10}, NOx, and SO_2.
- Emissions from start-up, shut-down, maintenance and malfunction would be subject to the cap.
- Compliance with the emissions limits would be based on comparing the annual emissions inventory with the facility-wide emissions limit for each covered pollutant. Any annual emissions inventory that exceeds the established pollutant emissions limit for the affected facility would be a violation of the rule.

---

[2] Except GHGs, which are based on 2011 through 2014 emissions due to the current unavailability of 2015 data.

1.5 PROJECT DESCRIPTION

The description of Regulation 11, Rule 18 and Regulation 12, Rule 16 are provided below.

1.5.1 REGULATION 11, RULE 18

The rule would require facilities that pose a site-wide health risk in excess of the risk action level threshold of ten per million (10/M) cancer risk or 1.0 hazard index for both chronic and acute risk to reduce that risk below the threshold through the implementation of a risk reduction plan approved by the Air District or demonstrate that all significant sources of toxic emissions are controlled TBARCT; a significant source of toxic emission is one that poses a health risk of 1.0/M cancer or 0.2 hazard index. The rule would be implemented in four phases based on either a facility's priority score (PS) or the toxic emissions source.

1.5.1.1 Objectives

The objectives of Toxic Risk Reduction Rule are to:

1) Reduce the public's exposure to health risks associated with the emissions of TACs from stationary sources;
2) Incorporate the most up-to-date health risk methodologies and health values into the Air District's risk evaluation process for existing stationary sources of TACs;
3) Ensure the facilities that impact the most sensitive and overburdened communities reduce their associated health risk in an efficient and expeditious manner;
4) Provide the public opportunity to comment on the draft HRAs to provide transparency and clarity to the process; and
5) Provide the public opportunity to comment on risk reduction plans as they are drafted by the affected facilities.

1.5.1.2 Administrative Procedures

The Toxic Risk Reduction Rule would utilize the annual toxic emissions inventories reported to the Air District by sources that emit toxic compounds. From the toxic emissions inventory data, Air District[3] would conduct a site-specific Health Risk Screening Analysis (HRSA). The HRSA assesses the potential for adverse health effects from public exposure to routine and predictable emissions of TACs. Procedures used for completing HRSAs are based on guidelines adopted by CARB/CAPCOA. From these HRSAs, the Air District would determine each facility's priority score (PS). The facility PS or the toxic emissions source type would be used to determine which phase a facility would be placed. In establishing the priority level for a facility, the Air District would consider:

(1) The amount of toxic pollutants emitted from the facility;
(2) The toxicity of these materials;
(3) The proximity of the facility to potential receptors; and
(4) Any other factors that the Air District deems to be important.

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[3] In order to complete the analyses in a timely manner. Some of the work may be completed by independent contractors working for the Air District under direction of Air District staff.

The rule would be implemented in four phases based on either a facility's PS or the toxic emissions source type as illustrated in Table 1.1. (Priority scores for all potentially affected facilities are expected to be completed by the end of 2017).

Table 1.1
Implementation Phases

Phase	Criterion	HRAs	Risk Reduction Plans	Plan Implementation
1	Cancer PS > 250 or Non-cancer PS >2.5	2017 – 2018	2018 – 2019	2019 – 2022
2	Cancer PS > 10 or Non-cancer PS >1.0	2019 – 2021	2021 – 2022	2022 – 2025
3	Diesel IC Engines	2021 – 2023	2023 – 2024	2024 – 2027
4	Retail Gas Stations	2023 – 2024	2024 – 2025	2025 – 2028

The Air District would conduct HRAs for facilities in accordance with the OEHHA HRA Guidelines and the CARB/CAPCOA Risk Management Guidelines that were updated in 2015. These Guidelines were updated pursuant to the Children's Environmental Health Protection Act (Senate Bill 25), which required that OEHHA develop health risk assessment procedures that ensure infants and children are protected from the harmful effects of air pollution. Using the results of the HRAs, the Air District would determine whether a facility would be affected by Rule 11-18. The rule would affect facilities with health risk impacts that exceeded any of the risk action level thresholds of ten per million (10/M) cancer risk or 1.0 hazard index for both chronic and acute risk. The Air District would notify facilities of their health risk score. A facility with a risk action level exceeding the threshold(s) will be required to reduce the risk below the threshold(s) by implementing a risk reduction plan within three years of plan approval, or demonstrate that all significant sources of toxic emissions are controlled by TBARCT within the same three-year period; a significant source of toxic emission is one that poses a health risk of 1.0/M cancer or 0.2 hazard index.

1.5.1.3 Health Risk Assessments

The Air District uses a variety of tools to determine where air quality health impacts may be occurring in the Bay Area, to assess the relative magnitude of these health impacts compared to other locations, and to determine how to best focus Air District resources in order to reduce these health impacts. HRAs are one of the tools that can be used to assess the relative magnitude of health hazards. HRAs are designed to quantify the potential health impacts that people and communities may be experiencing due to specific sources or facilities or that may occur in the future due to proposed projects or proposed changes at a facility. An HRA consists of four basic steps: 1) hazard identification; 2) exposure assessment; 3) dose response assessment; and 4) risk characterization. The Air District conducts HRAs using standardized methodologies for each of these steps. The Air District HRAs would be prepared in accordance with the most recent guidelines adopted by OEHHA in March 2015.

Air District staff believes that new facility-wide HRAs should be performed including improved emission inventories, updated health effects values, and the most recent HRA methodologies. rule 11-18 would require that the Air District conduct HRAs utilizing the most recent OEHHA HRA Guidelines along with more refined emissions inventories.

1.5.1.4 Pollutant Coverage

The Toxic Risk Reduction Rule would address TAC emissions from existing stationary sources. TAC emissions from new and modified sources are addressed under Air District Regulation 2, Rule 5. The California Health and Safety Code section 39655 defines a TAC as “an air pollutant which may cause or contribute to an increase in mortality or in serious illness, or which may pose a present or potential hazard to human health. A substance that is listed as a hazardous air pollutant pursuant to subsection (b) of Section 112 of the federal act (42 U.S.C. Sec. 7412(b)) is a toxic air contaminant.” For the purposes of this rule, TACs consists of the substances listed in Air District Regulation 2, Rule 5: New Source Review of Toxic Air Contaminants, Table 2-5-1.

Some of the key pollutants to be addressed under the Toxic Risk Reduction Rule include the following:

Benzene: Benzene is highly carcinogenic and occurs throughout the Bay Area. Most of the benzene emitted in the Bay Area comes from motor vehicles, including evaporative leakage and unburned fuel exhaust. Stationary sources contribute 13 percent of the benzene statewide. The primary stationary sources of benzene emissions include gasoline stations, petroleum refining, electricity generation, and cement production.

1,3-Butadiene: 1,3-butadiene is another carcinogen, with similar origins to benzene, namely mainly from gasoline evaporation and motor vehicle exhaust, biomass burning, petroleum refining and electricity generation.

Polycyclic aromatic hydrocarbons (PAHs): PAHs are a set of hydrocarbons formed of multiple benzene rings. Several PAHs have been shown to be carcinogenic, the best-studied of which is Benzo(a)pyrene. Although PAHs are emitted during petroleum refining, in the Bay Area the vast majority derive from fossil fuel and wood combustion.

Diesel Particulate Matter (DPM): DPM is the primary source of ambient risk based on risk analysis, followed by benzene and 1,3-butadiene. DPM emissions sources mainly include mobile sources, such as heavy-duty trucks, buses, construction equipment, locomotives, and ships, but also stationary sources such as stationary diesel engines and backup generators.

1.5.1.5 Source Coverage

The Toxic Risk Reduction Rule would apply to all sources of TAC emissions from “stationary sources” in the Bay Area. Stationary sources, as opposed to mobile sources such as trucks and other vehicles, are the sources over which the Air District has regulatory jurisdiction.

The Toxic Risk Reduction Rule would apply to a wide variety of sources and facilities located throughout the Bay Area, including data centers, petroleum refineries, chemical plants, waste water treatment facilities, foundries, forges, landfill operations, hospitals, crematoria, gasoline dispensing facilities (GDF) (i.e., gasoline stations), colleges and universities, military facilities and installations and airline operations. The Air District estimates that hundreds of facilities could be impacted by this rule.

1.5.2 REGULATION 12, RULE 16

1.5.2.1 Objectives

The objectives of the Refining Emission Caps are to:

1) Protect air quality, public health, and the climate from increases in annual facility-wide mass emissions of GHGs, PM, NOx, and SOx caused by changes in refinery oil feed quality or quantity, refinery or support equipment or operation, or combinations of these causes, by preventing any significant increase in these emissions;
2) Protect the climate and public health by preventing any significant increase in these emissions at refineries and associated facilities from increasing the emission intensity of the production of transportation fuels;
3) Protect community and public health by preventing any significant increase in these emissions from worsening hazards for which HRA methods may not account, including but not limited to acute and chronic ambient PM, NOx, SOx, and PM exposure hazards;
4) Complement other air quality, public health, and climate measures by discouraging investment in new refinery equipment that would lead to increased emissions of GHG, PM, NOx, or SOx from Bay Area refineries.

1.5.2.2 Pollutant Coverage

The Refining Cap Rule would limit the emissions of climate pollutants (GHGs) and three criteria pollutants (PM – both PM_{10} and $PM_{2.5}$, NOx, and SO_2) from refineries and other refining related facilities to a specific baseline plus an allowance; thereby establishing a "cap" for each of these emissions that the facility could not exceed.

Greenhouse Gases (GHGs): GHGs refer to gases that contribute to global warming. In addition to negative impacts on air quality as higher temperatures contribute to increased levels of ozone and PM, climate change may cause a wide range of ecological, social, economic, and demographic impacts. GHGs include carbon dioxide, methane, nitrous oxide, and fluorinated hydrocarbons. CO_2 is released to the atmosphere when fossil fuels (oil, gasoline, diesel, natural gas, and coal), solid waste, and wood or wood products are burned. CH_4 is emitted during the production and transport of coal, natural gas, and oil. Methane emissions also result from the decomposition of organic waste in municipal solid waste landfills and the raising of livestock. N_2O is emitted during agricultural and industrial activities, as well as during combustion of solid waste and fossil fuels. Fluorinated hydrocarbons: HFCs, PFCs, and SF_6, are generated in a variety of industrial processes. Although these gases are small in terms of their absolute mass, they are potent agents of climate change as expressed by their global warming potential.

Particulate Matter (PM): PM is a complex pollutant composed of an assortment of tiny airborne particles that vary in size and mass (ultrafine, fine, and coarse), physical state (solid or liquid), chemical composition, toxicity, and how they behave in the atmosphere. These particles originate from a variety of man-made and natural sources, including fossil fuel combustion, residential wood burning and cooking, wildfires, volcanoes, sea salt, and dust. Fine and ultrafine particles are so small, they can bypass the body's natural defenses and penetrate deep into the lungs, bloodstream, brain and other vital organs, and individual cells. Health studies have shown that exposure to PM can have a wide range of negative health effects, including triggering asthma attacks, chronic bronchitis, impaired lung development in children, heart attack, stroke, and premature death. Residential wood burning is the largest source of PM in the Bay Area during winter days. On an annual basis, mobile sources such as cars, trucks, ships and trains are the largest source of PM in the Bay Area.

Nitrogen Oxides (NOx): Nitrogen oxides are a group of gases that form when nitrogen reacts with oxygen during combustion, especially at high temperatures. These compounds (including nitric oxide and nitrogen dioxide), can contribute significantly to air pollution, especially in cities and areas with high motor vehicle traffic. In the Bay Area, nitrogen dioxide appears as a brown haze. At higher concentrations, nitrogen dioxide can damage sensitive crops, such as beans and tomatoes, and aggravate respiratory problems.

Sulfur Oxides (SOx): Heating and burning fossil fuels (such as coal and oil) release the sulfur present in these materials. In areas where large quantities of fossil fuels are used, sulfur oxides can be a major air pollution problem. The most common kind of sulfur oxide is SO_2. This substance can react with oxygen to form sulfur trioxide, which can form sulfuric acid mist in the presence of moisture. These contaminants can damage vegetation and negatively impact the health of both humans and animals.

1.5.2.3 Affected Facilities

The Refining Caps Rule would apply to each of the Bay Area's five petroleum refineries and to three additional support facilities. The five refineries are Chevron Refinery in Richmond, Shell Refinery in Martinez, Phillips 66 Refinery in Rodeo, Tesoro Refinery in Martinez, and Valero Refinery in Benicia. The three affected support facilities are Air Liquide in Richmond, Air Products in Martinez, and Martinez Cogen LP in Martinez.

1.5.2.4 The Emissions Limits

The draft emissions limit for each covered pollutant and each affected facility are shown in Table 1.2. A numeric limit on the annual mass emission rate of each air pollutant specified would be applied to each facility specified in the table. The limit is equal to the maximum-year actual emissions reported in 2011–2015[4] plus the additional allowance, or threshold factor, of seven percent that is intended to account for normal year-to-year variations in emissions.

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[4] Except GHGs, which are based on 2011 through 2014 emissions due to the current unavailability of 2015 data.

Table 1.2
The Enforceable Emissions Limits on Refinery-Wide Emissions [a]

Facility Name & Number	Pollutants				
	GHG[b] (thousands of metric tons)	**$PM_{2.5}$**[c] (tons)	**PM_{10}**[c] (tons)	**NOx**[c] (tons)	**SO_2**[c] (tons)
Chevron[d]: A-0010	4,774	502	526	971	394
Shell: A-0011	4,560	495	589	1,068	1,455
Phillips 66: A-0016	1,608	75	83	334	443
Tesoro: B-2758 / B-2759	2,615	77.7	97	1,015	644
Valero: B-2626 / B-3193	3,145	133	133	1,300	69.6
Martinez Cogen LP: A-1820	451	18.8	18.8	119	2.3
Air Liquide: B-7419	947	16.1	17.3	13.8	2.5
Air Products: B-0295	290	9.7	10.4	3.4	2.3

a. Annual facility-wide emission limits.
b. GHG: greenhouse gas emissions (CO_2e) as reported under Air Resources Board Mandatory Reporting. PM: filterable and condensable particulate matter.
c. $PM_{2.5}$ ("fine" particulate matter), PM_{10} ("respirable" particulate matter), NOx: oxides of nitrogen; SO_2: sulfur dioxide as reported in the Facility's annual emission inventory.
d. Facility owners or operators, as of August 2016, shown for information and context.

1.5.2.5 Changes in Monitoring Methods

CBE intends that these limits would change if the quantity of reported emissions changed solely due to a change in the method of monitoring or estimating emissions. Air District staff will work with CBE to capture this intent either in the rule language or in the plan for implementing the rule.

Chapter 2

Environmental Checklist

INTRODUCTION

The environmental checklist provides a standard evaluation tool to identify a project's adverse environmental impacts. This checklist identifies and evaluates potential adverse environmental impacts that may be created by the proposed project.

GENERAL INFORMATION

Project Title:	Regulation 11, Rule 18: Reduction of Risk from Air Toxic Emissions at Existing Facilities and Regulation 12, Rule 16: Petroleum Refining Facility-Wide Emissions Limits
Lead Agency Name and Address:	Bay Area Air Quality Management District 375 Beale Street, Suite 600 San Francisco, California 94105
Contact Person:	Victor Douglas
Contact Phone Number:	415-749-4752
Project Location:	The rules would apply to a multitude of facilities within the jurisdiction of the Bay Area Air Quality Management District, which encompasses all of Alameda, Contra Costa, Marin, San Francisco, San Mateo, Santa Clara, and Napa Counties and portions of southwestern Solano and southern Sonoma Counties.
Project Sponsor's Name and Address:	Bay Area Air Quality Management District 375 Beale Street, Suite 600 San Francisco, California 94105
General Plan Designation:	Rule 11-18 would apply to facilities that emit toxic pollutants and Rule 12-16 would affect the five petroleum refineries and three refinery-related facilities currently located in the Bay Area within the jurisdiction of the Air District: • Chevron Products Company (Richmond), • Phillips 66 Company – San Francisco Refinery (Rodeo), • Shell Martinez Refinery (Martinez), • Tesoro Refining and Marketing Company (Martinez), and • Valero Refining Company – California (Benicia). Rule 12-16 would also affect: • Air Liquide (Richmond), • Air Products (Martinez), and • Martinez Cogen LP (Martinez).
Zoning:	See "General Plan Designation" above
Description of Project:	See "Background" in Chapter 1.
Surrounding Land Uses and Setting:	See "Affected Area" in Chapter 1.
Other Public Agencies Whose Approval Is Required:	None

ENVIRONMENTAL FACTORS POTENTIALLY AFFECTED:

The following environmental impact areas have been assessed to determine their potential to be affected by the proposed project. As indicated by the checklist on the following pages, environmental topics marked with an "☑" may be adversely affected by the proposed project. An explanation relative to the determination of impacts can be found following the checklist for each area.

	Rule 11-18	**Rule 12-16**		**Rule 11-18**	**Rule 12-16**		**Rule 11-18**	**Rule 12-16**
Aesthetics	☐	☐	Agriculture and Forestry Resources	☐	☐	Air Quality	☑	☑
Biological Resources	☐	☐	Cultural Resources	☐	☐	Geology / Soils	☐	☐
Greenhouse Gas Emissions	☑	☑	Hazards & Hazardous Materials	☐	☑	Hydrology / Water Quality	☐	☑
Land Use / Planning	☐	☐	Mineral Resources	☐	☐	Noise	☐	☐
Population / Housing	☐	☐	Public Services	☐	☐	Recreation	☐	☐
Transportation / Traffic	☐	☐	Utilities / Service Systems	☐	☑	Mandatory Findings of Significance	☑	☑

DETERMINATION

On the basis of this initial evaluation:

☐ I find the proposed project COULD NOT have a significant effect on the environment, and that a NEGATIVE DECLARATION will be prepared.

☐ I find that although the proposed project could have a significant effect on the environment, there will not be significant effects in this case because revisions in the project have been made by or agreed to by the project proponent. A MITIGATED NEGATIVE DECLARATION will be prepared.

☑ I find that the proposed project MAY have a significant effect on the environment, and an ENVIRONMENTAL IMPACT REPORT is required.

☐ I find that the proposed project MAY have a "potentially significant impact" or “potentially significant unless mitigated” impact on the environment, but at least one effect 1) has been adequately analyzed in an earlier document pursuant to applicable legal standards, and 2) has been addressed by mitigation measures based on the earlier analysis as described on attached sheets. An ENVIRONMENTAL IMPACT REPORT is required, but it must analyze only the effects that remain to be addressed.

☐ I find that although the proposed project could have a significant effect on the environment, because all potentially significant effects (a) have been analyzed adequately in an earlier EIR or NEGATIVE DECLARATION pursuant to applicable standards, and (b) have been avoided or mitigated pursuant to that earlier EIR or NEGATIVE DECLARATION, including revisions or mitigation measures that are imposed upon the proposed project, nothing further is required.

Signature: Date:

Printed Name: Date:

EVALUATION OF ENVIRONMENTAL IMPACTS:

1) A brief explanation is required for all answers except "No Impact" answers that are adequately supported by the information sources a lead agency cites in the parentheses following each question. A "No Impact" answer is adequately supported if the referenced information sources show that the impact simply does not apply to projects like the one involved (e.g., the project falls outside a fault rupture zone). A "No Impact" answer should be explained where it is based on project-specific factors as well as general standards (e.g., the project will not expose sensitive receptors to pollutants, based on a project-specific screening analysis.

2) All answers must take account of the whole action involved, including off-site as well as on-site, cumulative as well as project-level, indirect as well as direct, and construction as well as operational impacts.

3) Once the lead agency has determined that a particular physical impact may occur, the checklist answers must indicate whether the impact is potentially significant, less than significant with mitigation, or less than significant. "Potentially Significant Impact" is appropriate if there is substantial evidence that an effect may be significant. If there are one or more "Potentially Significant Impact" entries when the determination is made, an EIR is required.

4) "Negative Declaration: Less Than Significant with Mitigation Incorporated" applies where the incorporation of mitigation measures has reduced an effect from "Potentially Significant Impact" to a "Less Than Significant Impact." The lead agency must describe the mitigation measures, and briefly explain how they reduce the effect to a less than significant level (mitigation measures from "Earlier Analyses," as described in (5) below, may be cross-referenced).

5) Earlier analyses may be used where, pursuant to the tiering, Program EIR, or other CEQA process, an effect has been adequately analyzed in an earlier EIR or negative declaration. Section 15063 (c)(3)(D). In this case, a brief discussion should identify the following:

   a) Earlier Analysis Used. Identify and state where they are available for review.

   b) Impacts Adequately Addressed. Identify which effects from the above checklist were within the scope of and adequately analyzed in an earlier document pursuant to applicable legal standards, and state whether such effects were addressed by mitigation measures based on the earlier analysis.

   c) Mitigation Measures. For effects that are "Less than Significant with Mitigation Measures Incorporated," describe the mitigation measures which were incorporated or refined from the earlier document and the extent to which they address site-specific conditions for the project.

6) Lead agencies are encouraged to incorporate into the checklist references to information sources for potential impacts (e.g., general plans, zoning ordinances). Reference to a previously prepared or outside document should, where appropriate, include a reference to the page or pages where the statement is substantiated.

7) Supporting Information Sources: A source list should be attached, and other sources used or individuals contacted should be cited in the discussion.

8) This checklist is only a suggested form, and lead agencies are free to use different formats; however, lead agencies should normally address the questions from this checklist that are relevant to a project's environmental effects in whatever format is selected.

9) The explanation of each issue should identify:

   a) the significance criteria or threshold, if any, used to evaluate each question; and

   b) the mitigation measure identified, if any, to reduce the impact to less than significance.

ENVIRONMENTAL CHECKLIST AND DISCUSSION

I. AESTHETICS.

Would the project:	Potentially Significant Impact	Less Than Significant Impact with Mitigation Incorporated	Less-than-Significant Impact	No Impact
a) Have a substantial adverse effect on a scenic vista?				
Rule 11-18	☐	☐	☐	☑
Rule 12-16	☐	☐	☐	☑
b) Substantially damage to scenic resources, including, but not limited to, trees, rock outcroppings, and historic buildings along a scenic highway?				
Rule 11-18	☐	☐	☐	☑
Rule 12-16	☐	☐	☐	☑
c) Substantially degrade the existing visual character or quality of the site and its surroundings				
Rule 11-18	☐	☐	☑	☐
Rule 12-16	☐	☐	☑	☐
d) Create a new source of substantial light or glare that would adversely affect daytime or nighttime views in the area?				
Rule 11-18	☐	☐	☑	☐
Rule 12-16	☐	☐	☑	☐

Setting

The Air District covers all of Alameda, Contra Costa, Marin, San Francisco, San Mateo, Santa Clara, and Napa Counties and portions of southwestern Solano and southern Sonoma Counties. The area of coverage is vast (about 5,600 square miles), so that land uses vary greatly and include commercial, industrial, residential, agricultural, and open space uses. Rule 11-18 would affect hundreds of facilities that cover a wide variety of industries and operations that emit toxic pollutants located throughout the Air District, including data centers, petroleum refineries, a cement kiln, gasoline dispensing facilities, hospitals, crematoria, etc. The rule would require affected facilities to reduce the health risk they pose using various risk reduction measure and controls. Rule 12-16 would affect the four petroleum refineries that are located in Contra Costa County and one that is located in Solano County (Valero) and also three refinery-related facilities located in Contra Costa County, all of which are in areas designated for industrial facilities.

The methods of control expected to be used to comply with Rule 11-18 are not expected to result in any aesthetic alterations of the facilities. Refineries and other facilities affected by Rule 12-16 are generally located in industrial areas and compliance is not expected to result in any aesthetic changes to the facilities. Scenic highways or corridors are generally not located in the vicinity of these facilities.

Regulatory Background

Visual resources are generally protected by the City and/or County General Plans through land use and zoning requirements.

Discussion of Impacts

I. a, b, and c).

Rule 11-18: Rule 11-18 would require facilities whose health risk is determined to exceed a specific action level to either reduce the facility risk below the action level or to install best available retrofit control technology on all significant sources of risk. Some control options include stack modifications. Stack modifications are another common and generally inexpensive risk reduction measure that are often used to reduce risk from back-up generators and soil remediation operations. Changing the direction of a stack (from horizontal to vertical, for example) and increasing the height of a stack to just above the height of nearby buildings will increase the dispersion of the emissions from that stack and will typically result in lower ground level air concentrations at nearby receptors and lower health risks. Stack modifications may change the existing visual character or quality of a facility but are not expected to have significant adverse aesthetic impacts to the surrounding community as they would be expected to occur in industrial or commercial areas. Regulation 11-18 could also result in the installation of new air pollution control equipment to mitigate TAC emissions. While these control devices may be visible to surrounding areas, they would be installed within existing industrial or commercial areas, would be subject to local height limits, and are not expected to block any scenic vista, degrade the visual character or quality of the area, or result in significant adverse aesthetic impacts.

Rule 12-16: Rule 12-16 would limit air emissions of GHGs and certain criteria pollutants ($PM_{2.5}$, PM_{10}, NOx, and SO_2) from Bay Area petroleum refineries and three refinery-related facilities to the historic highest emission rate over a recent multi-year period, with an additional seven-percent margin to account for operational variations. Rule 12-16 is not expected to require the construction of any substantial new structures that would impact the views of the refineries or areas outside of existing refinery boundaries, provided existing crude and product slates remain relatively constant. However, because crude and product slates vary over time and these changes may result in changes in the emissions profile of a refinery, there is the potential that Rule 12-16 could result in the need for better controls on various refinery sources, (e.g. boilers and heaters) to mitigate any potential emissions increase. These emission controls could lead to changes in operations or installation of new air pollution control devices. While these control devices may be visible to surrounding areas, they would be installed within existing industrialized areas and are not expected to be taller than existing refinery structures. Any new equipment would be located within the refineries, would be compatible with the urban/developed nature of the refineries, are not expected to block any scenic vista, degrade the visual character or quality of the area, or result in any adverse aesthetic impacts. Once implemented, equipment associated with the rule is not expected to be noticeably visible within the refineries. Therefore, the rule is not expected to have adverse aesthetic impacts to the surrounding community.

I. d).

Rule 11-18: The facilities affected by Rule 11-18, including petroleum refineries, may need to install or modify air pollution control equipment or modify operations as to implement risk reduction measures. However, it is unlikely that any of the changes would result in additional night-time operation that would require extra lighting. New light sources, if any, are not expected to be noticeable in residential areas. Most local land use agencies have ordinances that limit the intensity of lighting and its effects on adjacent property owners. Therefore, the rule is not expected to have significant adverse aesthetic impacts to the surrounding community.

Rule 12-16: The facilities affected by the Regulation 12-16 may be required to install additional air pollution control equipment or modify operations. Further, refinery modifications could require additional lighting. However, refineries are already lighted for night-time operations and safety measures, and are located in appropriately zoned areas that are not usually located next to residential areas. New light sources, if any, are not expected to be noticeable in residential areas. Most local land use agencies have ordinances that limit the intensity of lighting and its effects on adjacent property owners. Therefore, the rule is not expected to have significant adverse aesthetic impacts to the surrounding community.

Conclusions

Based upon the above considerations, significant adverse project-specific impacts to aesthetics are not expected to occur due to implementation of either Rule 11-18 or Rule 12-16 and, therefore, will not be further evaluated in the Draft EIR.

II. AGRICULTURE AND FORESTRY RESOURCES.

In determining whether impacts on agricultural resources are significant environmental effects, lead agencies may refer to the California Agricultural Land Evaluation and Site Assessment Model (1997) prepared by the California Department of Conservation as an optional model to use in assessing impacts on agriculture and farmland. In determining whether impacts to forest resources, including timberland, are significant environmental effects, lead agencies may refer to information compiled by the California Department of Forestry and Fire Protection regarding the state's inventory of forest land, including the Forest and Range Assessment Project and the Forest Legacy Assessment project; and forest carbon measurement methodology provided in Forest Protocols adopted by the California Air Resources Board.

Would the project:	Potentially Significant Impact	Less Than Significant Impact with Mitigation Incorporated	Less-than-Significant Impact	No Impact
a) Convert Prime Farmland, Unique Farmland, or Farmland of Statewide Importance (Farmland), as shown on the maps prepared pursuant to the Farmland Mapping and Monitoring Program of the California Resources Agency, to non-agricultural use?				
Rule 11-18	☐	☐	☐	☑
Rule 12-16	☐	☐	☐	☑
b) Conflict with existing zoning for agricultural use or conflict with a Williamson Act contract?				
Rule 11-18	☐	☐	☐	☑
Rule 12-16	☐	☐	☐	☑
c) Conflict with existing zoning for, or cause rezoning of, forest land as defined in Public Resources Code section 12220(g)), timberland (as defined by Public Resources Code section 4526), or timberland zoned Timberland Production (as defined by Government Code section 51104(g))?				
Rule 11-18	☐	☐	☐	☑
Rule 12-16	☐	☐	☐	☑
d) Result in the loss of forest land or conversion of forest land to non-forest use?				
Rule 11-18	☐	☐	☐	☑
Rule 12-16	☐	☐	☐	☑
e) Involve other changes in the existing environment which, due to their location or nature, could result in conversion of Farmland, to non-agricultural use or conversion of forest land to non-forest use?				
Rule 11-18	☐	☐	☐	☑
Rule 12-16	☐	☐	☐	☑

Setting

The BAAQMD covers all of Alameda, Contra Costa, Marin, San Francisco, San Mateo, Santa Clara, and Napa Counties and portions of southwestern Solano and southern Sonoma Counties. The area of coverage is vast (about 5,600 square miles) so that land uses vary greatly and include commercial, industrial, residential, agricultural, and open space uses. Some of these agricultural lands are under Williamson Act contracts.

Rule 11-18 would affect hundreds of facilities that cover a wide variety of industries and operations that emit toxic pollutants located throughout the Air District, including data centers, petroleum refineries, a cement kiln, gasoline dispensing facilities, hospitals, crematoria, etc. The rule would require affected facilities to reduce the health risk they pose using various risk reduction measure and controls. Rule 12-16 would affect the four petroleum refineries that are located in Contra Costa County and one that is located in Solano County (Valero) and also three refinery-related facilities located in Contra Costa County.

Regulatory Background

Agricultural and forest resources are generally protected by the City and/or County General Plans, Community Plans through land use and zoning requirements, as well as any applicable specific plans, ordinances, local coastal plans, and redevelopment plans.

Discussion of Impacts

II. a, b, c, d, and e).

Rule 11-18: The facilities and operation that would be affected by Rule 11-18 are located primarily in industrial and commercial areas where agricultural or forest resources are generally not located. Some construction activity is expected to result from compliance with Rule 11-18; but such activities are expected to occur on the premises of the affected facilities and, therefore, would not impact agricultural and forestry resources.

Rule 12-16: The affected refineries and refinery-related facilities are located in industrial areas where agricultural or forest resources are generally not located. Rule 12-16 could require air pollution control equipment on various refinery sources or changes in operations at any or all of the Bay Area refineries to ensure compliance with the emissions limits. Construction activities may be associated with compliance with Rule 12-16. Such construction activities are expected to be limited to the existing refineries. No agricultural or forest resources are located within the boundaries of the existing refineries, and construction activities would not convert any agricultural or forest land into non-agricultural or non-forest use, or involve Williamson Act contracts.

Conclusions

Based upon the above considerations, significant adverse project-specific impacts to agriculture and forest resources are not expected to occur due to implementation of either Rule 11-18 or Rule 12-16 and, therefore, will not be further evaluated in the Draft EIR.

III. AIR QUALITY.

Where available, the significance criteria established by the applicable air quality management or air pollution control district may be relied upon to make the following determinations.

Would the project:	Potentially Significant Impact	Less Than Significant Impact with Mitigation Incorporated	Less-than-Significant Impact	No Impact
a) Conflict with or obstruct implementation of the applicable air quality plan?				
Rule 11-18	☐	☐	☐	☑
Rule 12-16	☐	☐	☐	☑
b) Violate any air quality standard or contribute to an existing or projected air quality violation?				
Rule 11-18	☑	☐	☐	☐
Rule 12-16	☑	☐	☐	☐
c) Result in a cumulatively considerable net increase of any criteria pollutant for which the project region is a nonattainment area for an applicable federal or state ambient air quality standard (including releasing emissions that exceed quantitative thresholds for ozone precursors)?				
Rule 11-18	☑	☐	☐	☐
Rule 12-16	☑	☐	☐	☐
d) Expose sensitive receptors to substantial pollutant concentrations?				
Rule 11-18	☑	☐	☐	☐
Rule 12-16	☑	☐	☐	☐
e) Create objectionable odors affecting a substantial number of people?				
Rule 11-18	☐	☐	☐	☑
Rule 12-16	☐	☐	☐	☑

Setting

It is the responsibility of the BAAQMD to ensure that state and federal ambient air quality standards are achieved and maintained in its geographical jurisdiction. Health-based air quality standards have been established by California and the federal government for the following criteria air pollutants: ozone, carbon monoxide (CO), nitrogen dioxide (NO_2), particulate matter less than 10 microns in diameter (PM_{10}), particulate matter less than 2.5 microns in diameter ($PM_{2.5}$), sulfur dioxide (SO_2), and lead.

Air quality conditions in the San Francisco Bay Area have improved since the Air District was created in 1955. Ambient concentrations of air pollutants and the number of days on which the region exceeds air quality standards have fallen. The Air District is in attainment of the State and federal ambient air quality standards for CO, nitrogen oxides (NOx), and SO_2 and the federal 24-hour standard for $PM_{2.5}$. The Air District is not considered to be in attainment with the State PM_{10} and $PM_{2.5}$ standards. The Bay Area is designated as non-attainment for the federal 8-hour and California 1- and 8-hour ozone standards.

Regulatory Background

Criteria Pollutants

At the federal level, the Clean Air Act (CAA) Amendments of 1990 give the U.S. EPA additional authority to require states to reduce emissions of ozone precursors and particulate matter in non-attainment areas. The amendments set attainment deadlines based on the severity of problems. At the state level, CARB has traditionally established state ambient air quality standards, maintained oversight authority in air quality planning, developed programs for reducing emissions from motor vehicles, developed air emission inventories, collected air quality and meteorological data, and approved state implementation plans. At a local level, California's air districts, including the BAAQMD, are responsible for overseeing stationary source emissions, approving permits, maintaining emission inventories, maintaining air quality monitoring stations, overseeing agricultural burning permits, and reviewing air quality-related sections of environmental documents required by CEQA.

The BAAQMD is governed by a 24-member Board of Directors composed of publicly-elected officials apportioned according to the population of the represented counties. The Board has the authority to develop and enforce regulations for the control of air pollution within its jurisdiction. The BAAQMD is responsible for implementing emissions standards and other requirements of federal and state laws. It is also responsible for developing air quality planning documents required by both federal and state laws.

Toxic Air Contaminants

TACs are regulated in the District through federal, state, and local programs. At the federal level, TACs are regulated primarily under the authority of the CAA. Prior to the amendment of the CAA in 1990, source-specific NESHAPs were promulgated under Section 112 of the CAA for certain sources of radionuclides and Hazardous Air Pollutants (HAPs).

Title III of the 1990 CAA amendments requires U.S. EPA to promulgate NESHAPs on a specified schedule for certain categories of sources identified by U.S. EPA as emitting one or more of the 189 listed HAPs. Emission standards for major sources must require the maximum achievable control technology (MACT). MACT is defined as the maximum degree of emission reduction achievable considering cost and non-air quality health and environmental impacts and energy requirements. All NESHAPs were to be promulgated by the year 2000. Specific incremental progress in establishing standards were to be made by the years 1992 (at least 40 source categories), 1994 (25 percent of the listed categories), 1997 (50 percent of remaining listed categories), and 2000 (remaining balance). The 1992 requirement was met; however, many of the four-year standards were not promulgated as scheduled. Promulgation of those standards has been rescheduled based on court ordered deadlines, or the aim to satisfy all Section 112 requirements in a timely manner.

Many of the sources of TACs that have been identified under the CAA are also subject to the California TAC regulatory programs. CARB developed three regulatory programs for the control of TACs. Each of the programs is discussed in the following subsections.

Control of TACs Under the TAC Identification and Control Program: California's TAC identification and control program, adopted in 1983 as Assembly Bill 1807 (AB 1807) (California Health and Safety Code §39662), is a two-step program in which substances are identified as TACs and airborne toxic control measures (ATCMs) are adopted to control emissions from specific sources. Since adoption of the program, CARB has identified 18 TACs, and CARB adopted a regulation designating all 189 federal HAPs as TACs.

Control of TACs Under the Air Toxics "Hot Spots" Act: The Air Toxics Hot Spot Information and Assessment Act of 1987 (AB 2588) (California Health and Safety Code §39656) established a state-wide program to inventory and assess the risks from facilities that emit TACs and to notify the public about significant health risks associated with those emissions. Inventory reports must be updated every four years under current state law. In its implementation of that program, the BAAQMD used a maximum individual cancer risk of 10 in one million (10/M), or an ambient concentration above a non-cancer reference exposure level, as the threshold for notification. Using the best science available at the time, only a relatively small number of facilities exceeded that threshold.

Senate Bill (SB) 1731, enacted in 1992 (California Health and Safety Code §44390 et seq.), amended AB 2588 to include a requirement for facilities with significant risks to prepare and implement a risk reduction plan to reduce the risk below a defined significant risk level within specified time limits. At a minimum, such facilities must, as quickly as feasible, reduce cancer risk levels that exceed 100 per one million (100/M). The BAAQMD adopted risk reduction requirements for perchloroethylene dry cleaners to fulfill the requirements of SB 1731. No facilities within the Bay Area currently exceed the 100/M threshold that would require risk reductions.

Targeted Control of TACs Under the Community Air Risk Evaluation Program: In 2004, BAAQMD initiated the Community Air Risk Evaluation (CARE) program to identify areas with relatively high concentrations of air pollution, including toxic air contaminants (TACs) and fine particulate matter, and populations most vulnerable to air pollution's health impacts. Maps of communities most impacted by air pollution, generated through the CARE program, have been integrated into many BAAQMD programs. For example, BAAQMD uses information derived from the CARE program to develop and implement targeted risk reduction programs, including grant and incentive programs, community outreach efforts, collaboration with other governmental agencies, model ordinances, new regulations for stationary sources and indirect sources, and advocacy for additional legislation.

Discussion of Impacts

III. a).

Neither Rule 11-18 nor Rule 12-16 is expected to conflict with or obstruct implementation of the applicable air quality plan. The 2010 Bay Area Clean Air Plan (CAP) was approved by the Air

District's Board of Directors on September 15, 2010 and is the approved air quality plan that the Air District operates under.

Rule 11-18: Rule 11-18 would require facilities that pose a health risk in excess of the risk action level threshold of ten per million (10/M) cancer risk or 1.0 hazard index for both chronic and acute risk to reduce that risk below the threshold through the implementation of a risk reduction plan approved by the Air District or demonstrate that all significant sources of toxic emissions are control by TBARCT; a significant source of toxic emission would be one that poses a health risk of 1.0/M cancer or 0.2 hazard index. The rule would be implemented in four phases based on either a facility's priority score (PS) or the toxic emissions source type as illustrated in Table 2.1. (Priority scores for all potentially affected facilities are expected to be completed by the end of 2017). Reducing TAC emissions from these facilities would be in harmony with the aims of the 2010 CAP and, therefore, Rule 11-18 would not conflict with or obstruct implementation of the 2010 CAP as it is not expected to interfere with any other District rules and regulations.

Table 2.1 – Rule 11-18 Implementation Phases

Phase	Criterion	HRAs	Risk Reduction Plans	Plan Implementation
1	Cancer PS > 250 or Non-cancer PS >2.5	2017 – 2018	2018 – 2019	2019 – 2022
2	Cancer PS > 10 or Non-cancer PS >1.0	2019 – 2021	2021 – 2022	2022 – 2025
3	Diesel Engines	2021 – 2023	2023 – 2024	2024 – 2027
4	Retail Gas Stations	2023 – 2024	2024 – 2025	2025 – 2028

Rule 12-16: Rule 12-16 would establish facility-wide emissions limits for GHGs, $PM_{2.5}$ and PM_{10}, NOx, and SO_2 at each of the five Bay Area refineries and three refinery-related facilities. Any affected facility that exceeds an emission limit would be a violation of the rule. Limiting emissions from these facilities would be in harmony with the aims of the 2010 CAP and, therefore, Rule 12-16 would not conflict with or obstruct implementation of the 2010 CAP.

III. b, c, and d).

Rule 11-18: Rule 11-18 would reduce the health risk level at which facilities must reduce their risk. There are a large variety of control technologies and measures that could be used to reduce the health risk posed by a facility. A limited listing of such measures is presented in Table 2.2 below.

Table 2.2 – Risk Reduction Measures and Target Substances

Risk Reduction Measure	Substance Group	Control Efficiency
Enclosures	Particulates	Varied
Capture and Collection Systems	VOCs and Particulates	Varied
Diesel Particulate Filter	Particulates	85%
Baghouse	Particulates	99-99.9%

Risk Reduction Measure	Substance Group	Control Efficiency
HEPA filter and pre-filter	Particulates	99.9-99.99%
Carbon Adsorption	VOCs	90-99%
Thermal and Catalytic Oxidizers	VOCs and Inorganic Gases	98-99.9%
Reduced Throughput or Operating Time	VOCS and Particulates	Varied
Alternative Technologies	Particulates	Up to 100%
Product Substitution	VOCs	Up to 100%
Relocate Source or Stack	All TAC Types	Not Applicable
Stack Modifications	All TAC Types	Not Applicable

While the primary purpose of implementing risk reduction measures such as installing air pollution control equipment or making operational changes is to reduce health risks, some types of control equipment have the potential to create secondary adverse air quality impacts. For example, increased NOx emissions could result if VOC emissions are controlled through a combustion process (e.g., afterburner) or require additional energy to operate.

Because of the potential for secondary emissions from air pollution control equipment, there is a potential that sensitive receptors could be exposed to increased pollutant concentrations, which could be significant. As a result, these potential air quality impacts will be evaluated in the Draft EIR.

Rule 12-16: A number of air quality rules and regulations that apply to refineries are enforced by the BAAQMD. These existing rules and regulations require: (1) air permits; (2) the use of best available control technology (BACT); (3) new source review for new emission sources and offsets for new emissions; (4) control of toxic air contaminants; (5) control of fugitive emission sources including storage tanks, equipment leaks, bulk loading, and wastewater separators; and (6) control of emissions from combustion sources, including process heaters, boilers, internal combustion engines, gas turbines, catalytic cracking and reforming units, and flares. Rule 12-16 could require modifications to refineries to ensure changes in operations do not result in emissions increases either through the installation of air pollution control equipment or changes in operations.

Although the primary effect of installing air pollution control equipment is to reduce emissions of a particular pollutant, e.g., VOCs, some types of control equipment have the potential to create secondary adverse air quality impacts, e.g., increased NOx emissions if VOC emissions are controlled through a combustion process (e.g., afterburner) or require additional energy to operate. Control measures aimed at reducing NOx from stationary sources may use ammonia for control (e.g., selective catalytic reduction). Ammonia use could result in increased ammonia emissions and, since ammonia is a precursor to particulate formation, increased particulate formation in the atmosphere. Because of the potential for secondary emissions from air pollution control equipment, there is a potential that sensitive receptors could be exposed to increased pollutant concentrations, which could be significant. As a result, these potential air quality impacts of Rule 12-16 will be evaluated in the Draft EIR.

III. e).

Rule 11-18: Rule 11-18 would require facilities that pose significant health risks to develop a plan to reduce that risk or apply TBARCT to all significant sources of risk at the facility. The measures that a facility could potentially implement to reduce its risk are listed above in Table 2.2 and generally would not result in the creation of objectionable odors that could affect a substantial number of people.

Rule 12-16: Rule 12-16 would establish facility-wide emissions limits for GHGs, $PM_{2.5}$ and PM_{10}, NOx, and SO_2 at each of the five Bay Area refineries and three refinery-related facilities. The rule is not expected to result in an increase in odorous emissions at the refineries. Odorous emissions are not specifically covered by Rule 12-16 and while not specifically aimed at reducing emissions of compounds that are considered odorous, e.g., hydrogen sulfide (H_2S), which is the primary odorous compound emitted from the refineries, the rule would not result in an increase in H_2S or other odorous sulfur-containing compounds. Therefore, the rule is not expected to result in an increase in the generation of emissions that could generate odors.

Conclusions

Implementation of Rule 11-18 would reduce risk from facilities that emit toxic air contaminants throughout the Bay Area. However, certain risk reduction measures have the potential to increase emissions of other pollutants, such as GHGs and criteria pollutants. Implementation of Rule 12-16 would prevent refinery emissions of GHGs and some criteria pollutants from increasing. Similarly, secondary adverse air quality impacts could occur from installing control equipment at individual refineries in response to changes that could increase emissions of criteria pollutants. Adverse impacts include increased criteria pollutant and TAC emissions from certain types of air pollution control equipment. Therefore, potential adverse secondary air quality impacts which could result from implementing either Rule 11-18 or Rule 12-16 will be evaluated in the Draft EIR. No significant impacts were identified on air quality plans or the generation of odors and these topics will not be addressed further in the Draft EIR.

IV. BIOLOGICAL RESOURCES.

Would the project:	Potentially Significant Impact	Less Than Significant Impact with Mitigation Incorporated	Less-than-Significant Impact	No Impact
a) Have a substantial adverse effect, either directly or through habitat modifications, on any species identified as a candidate, sensitive, or special status species in local or regional plans, policies, or regulations, or by the California Department of Fish and Wildlife or U.S. Fish and Wildlife Service?				
Rule 11-18	☐	☐	☐	☑
Rule 12-16	☐	☐	☐	☑
b) Have a substantial adverse effect on any riparian habitat or other sensitive natural community identified in local or regional plans, policies, or regulations, or by the California Department of Fish and Wildlife or U.S. Fish and Wildlife Service?				
Rule 11-18	☐	☐	☐	☑
Rule 12-16	☐	☐	☐	☑
c) Have a substantial adverse effect on federally protected wetlands as defined by Section 404 of the Clean Water Act (including, but not limited to, marsh, vernal pool, coastal wetlands, etc.) through direct removal, filling, hydrological interruption, or other means?				
Rule 11-18	☐	☐	☐	☑
Rule 12-16	☐	☐	☐	☑
d) Interfere substantially with the movement of any native resident or migratory fish or wildlife species or with established native resident or migratory wildlife corridors, or impede the use of native wildlife nursery sites?				
Rule 11-18	☐	☐	☐	☑
Rule 12-16	☐	☐	☐	☑
e) Conflicting with any local policies or ordinances protecting biological resources, such as a tree preservation policy or ordinance?				
Rule 11-18	☐	☐	☐	☑
Rule 12-16	☐	☐	☐	☑

Would the project:	Potentially Significant Impact	Less Than Significant Impact with Mitigation Incorporated	Less-than-Significant Impact	No Impact
f) Conflict with the provisions of an adopted habitat conservation plan, natural community conservation plan, or other approved local, regional, or state habitat conservation plan?				
Rule 11-18	☐	☐	☐	☑
Rule 12-16	☐	☐	☐	☑

Setting

The BAAQMD covers all of Alameda, Contra Costa, Marin, San Francisco, San Mateo, Santa Clara, and Napa Counties and portions of southwestern Solano and southern Sonoma Counties. The area of coverage is vast (about 5,600 square miles) so that land uses vary greatly and include commercial, industrial, residential, agricultural, and open space uses. A wide variety of biological resources are located within the Bay Area.

The areas affected by the rules are located in the Bay Area-Delta Bioregion (as defined by the State's Natural Communities Conservation Program). This Bioregion is comprised of a variety of natural communities, which range from salt marshes to chaparral to oak woodland.

Rule 11-18: Hundreds of facilities located throughout the Bioregion would be affected by Rule 11-18. The facilities that would be affected by Rule 11-18 are expected to be located in developed commercial and industrial areas within the Bay Area. These commercial/industrial areas have been graded to develop the various structures, and are typically surrounded by other commercial and industrial facilities. Native vegetation, other than landscape vegetation, has usually been removed from these facilities.

Rule 12-16: Four of the refineries affected by the Rule 12-16 are located in Contra Costa County and one is located in Solano County (Valero). The refineries affected by Rule 12-16 have been developed with various permanent refinery structures, buildings, operating units and storage tanks. Native vegetation, other than landscape vegetation, has generally been removed from the refineries to minimize safety and fire hazards.

Regulatory Background

Biological resources are protected by the City and/or County General Plans through land use and zoning requirements which minimize or prohibit development in biologically sensitive areas. Biological resources are also protected by the California Department of Fish and Wildlife, and the U.S. Fish and Wildlife Service. The U.S Fish and Wildlife Service and National Marine Fisheries Service oversee the federal Endangered Species Act. Development permits may be required from one or both of these agencies if development would impact rare or endangered species. The California Department of Fish and Wildlife administers the California Endangered Species Act which prohibits impacting endangered and threatened species. The U.S. Army Corps of Engineers and the U.S. Environmental Protection

Agency (U.S. EPA) regulate the discharge of dredge or fill material into waters of the United States, including wetlands.

Discussion of Impacts

IV. a), b), and d).

Rule 11-18: The facilities affected by Rule 11-18 are expected to be located in the commercial and industrial areas within the Bay Area. These commercial/industrial areas have been graded to develop the various structures, and are typically surrounded by other commercial and industrial facilities. Native vegetation, other than landscape vegetation, has usually been removed from these facilities.

Similarly, modifications at existing facilities would not interfere substantially with the movement of any native resident or migratory fish or wildlife species or with native or resident or migratory wildlife corridors, or impede the use of native wildlife nursery sites. Further, since the Rule 11-18 would primarily regulate stationary emission sources at commercial or industrial facilities, it would not directly or indirectly affect riparian habitat or other sensitive natural communities identified in local or regional plans, policies, or regulations, or identified by the CDFG or U.S. Fish and Wildlife Service. Improved air quality resulting from Rule 11-18 would be expected to provide health benefits to plant and animal species in the District.

Rule 12-16: No impacts on biological resources are anticipated from the Rule 12-16 which would apply to existing refineries. The refinery facilities have been graded and developed, and biological resources, with the exception of landscape species, have been removed. Construction of any air pollution control equipment would take place within the operating portions of existing refineries which are void of biological resources. As a result, there would be no direct or indirect impact on sensitive biological resources riparian habitats, or protected wetlands. The installation of air pollution control equipment would also not interfere with the movement of any migratory fish or wildlife species or affect migratory corridors; would not conflict with local policies or ordinances protecting biological resources; and would not conflict with an adopted habitat conservation plan.

IV. c).

Rule 11-18: No direct or indirect impacts from implementing the Rule 11-18 were identified which could adversely affect plant and/or animal species in the District. Implementing the Rule 11-18 would result in installation of new or modifications of existing equipment at commercial or industrial facilities to control or further control toxic emissions. Existing commercial or industrial facilities are generally located in appropriately zoned commercial or industrial areas, this work would not impact marshes, vernal pools, wetlands, etc. For these reasons the rule is not expected to adversely affect protected wetlands as defined by §404 of the Clean Water Act, including, but not limited to marshes, vernal pools, coastal wetlands, etc., through direct removal, filling, hydrological interruption or other means.

Rule 12-16: Compliance with the Rule 12-16 could result in the installation of additional air pollution control equipment at existing refineries. The installation of air pollution control equipment at these facilities would be consistent with industrial land uses. The operating portions of the existing refineries do not contain marshes, vernal pools, wetlands, etc. Therefore, construction would not impact these biological resources. For these reasons the rule is not expected to adversely affect protected wetlands as defined by §404 of the Clean Water Act, including, but not limited to marshes, vernal pools, coastal wetlands, etc., through direct removal, filling, hydrological interruption or other means.

IV. e and f).

Rule 11-18: Rule 11-18 may require modifications at existing industrial or commercial facilities to control or further control emissions at these affected facilities. As a result, the rule will not conflict with any land use policies or ordinances protecting biological resources. Similarly, the rule will not conflict with any habitat conservation or natural community conservation plans, agricultural resources or operations, and would not create divisions in any existing communities.

Rule 12-16: Rule 12-16 wills not conflict with any land use plans, local policies or ordinances, or regulations protecting biological resources for the reasons already given. Similarly, the rule is not expected to conflict with any habitat conservation or natural community conservation plans, agricultural resources or operations, and would not create divisions in any existing communities.

Conclusions

Based upon the above considerations, significant adverse project-specific impacts to biological resources are not expected to occur due to implementation of either Rule 11-18 or Rule 12-16 and, therefore, will not be further evaluated in the Draft EIR.

V. CULTURAL RESOURCES.

Would the project:	Potentially Significant Impact	Less Than Significant Impact with Mitigation Incorporated	Less-than-Significant Impact	No Impact
a) Cause a substantial adverse change in the significance of a historical resource as defined in §15064.5?				
Rule 11-18	☐	☐	☐	☑
Rule 12-16	☐	☐	☐	☑
b) Cause a substantial adverse change in the significance of an archaeological resource pursuant to §15064.5?				
Rule 11-18	☐	☐	☐	☑
Rule 12-16	☐	☐	☐	☑
c) Directly or indirectly destroy a unique paleontological resource or site or unique geologic feature?				
Rule 11-18	☐	☐	☐	☑
Rule 12-16	☐	☐	☐	☑
d) Disturb any human remains, including those interred outside of formal cemeteries?				
Rule 11-18	☐	☐	☐	☑
Rule 12-16	☐	☐	☐	☑

Setting

The BAAQMD covers all of Alameda, Contra Costa, Marin, San Francisco, San Mateo, Santa Clara, and Napa Counties and portions of southwestern Solano and southern Sonoma Counties. The area of coverage is vast (about 5,600 square miles) so that land uses vary greatly and include commercial, industrial, residential, agricultural and open space uses. Cultural resources are defined as buildings, sites, structures, or objects which might have historical architectural, archaeological, cultural, or scientific importance.

The Carquinez Strait represents the entry point for the Sacramento and San Joaquin Rivers into the San Francisco Bay. This locality lies within the San Francisco Bay and the west end of the Central Valley archaeological regions, both of which contain a rich array of prehistoric and historical cultural resources. The areas surrounding the Carquinez Strait and Suisun Bay have been occupied for millennia.

Regulatory Background

The State CEQA Guidelines define a significant cultural resource as a "resource listed or eligible for listing on the California Register of Historical Resources" (Public Resources Code §5024.1). A project would have a significant impact if it would cause a substantial adverse change in the significance of a historical resource (State CEQA Guidelines §15064.5(b)). A substantial adverse change in the significance of a historical resource would result from an action that would demolish or adversely alter the physical characteristics of the historical resource that convey its historical significance and that qualify the resource for inclusion in the California Register of Historical Resources or a local register or survey that meets the requirements of Public Resources Code §§50020.1(k) and 5024.1(g).

Discussion of Impacts

V. a, b, c and d).

Rule 11-18: Implementing Rule 11-18 is primarily expected to result in controlling stationary source emissions at commercial or industrial facilities. Affected facilities are typically located in appropriately zoned commercial or industrial areas that have previously been graded and developed. Because stationary source emissions from existing facilities does not typically require extensive cut-and-fill activities, or excavation, it is unlikely that additional stationary source control measures that may result from Rule 11-18 will: (1) adversely affect historical or archaeological resources as defined in CEQA Guidelines §15064.5; (2) destroy unique paleontological resources or unique geologic features; or (3) disturb human remains interred outside formal cemeteries.

In a small number of cases, the Rule 11-18 may require minor site preparation and grading at an affected facility to install new or modify existing equipment. Under this circumstance, it is possible that archaeological or paleontological resources could be uncovered. Even if this circumstance were to occur, significant adverse cultural resource impacts are not anticipated because there are existing laws in place that are designed to protect and mitigate potential adverse impacts to cultural resources. As with any construction activity, should archaeological resources be found during construction that results from implementing the rule, the activity would cease until a thorough archaeological assessment is conducted.

Rule 12-16: No impacts on cultural resources are anticipated from the Rule 12-16 that would apply to existing refineries. Historic resources are typically not located within refineries and no demolition activities are expected to be required. As a result, no impacts on historic resources are expected. Construction activities would be limited to areas within existing refineries boundaries, i.e., within areas that have already been graded and developed. Therefore, construction activities are not expected to impact cultural resources, including historical and archaeological resources, either directly or indirectly, or disturb human remains.

Conclusions

Based upon the above considerations, significant adverse project-specific impacts to cultural resources are not expected to occur due to implementation of Rule 11-18 and 12-16 and, therefore, will not be further evaluated in the Draft EIR.

VI. GEOLOGY AND SOILS.

Would the project:	Potentially Significant Impact	Less Than Significant Impact with Mitigation Incorporated	Less-than-Significant Impact	No Impact
a) Expose people or structures to potential substantial adverse effects, including the risk of loss, injury, or death involving:				
i) Rupture of a known earthquake fault, as delineated on the most recent Alquist-Priolo Earthquake Fault Zoning Map issued by the State Geologist for the area or based on other substantial evidence of a known fault? Refer to Division of Mines and Geology Special Publication 42.				
Rule 11-18	☐	☐	☐	☑
Rule 12-16	☐	☐	☐	☑
ii) Strong seismic ground shaking?				
Rule 11-18	☐	☐	☑	☐
Rule 12-16	☐	☐	☑	☐
iii) Seismic-related ground failure, including liquefaction?				
Rule 11-18	☐	☐	☑	☐
Rule 12-16	☐	☐	☑	☐
iv) Landslides?				
Rule 11-18	☐	☐	☑	☐
Rule 12-16	☐	☐	☑	☐
b) Result in substantial soil erosion or the loss of topsoil?				
Rule 11-18	☐	☐	☐	☑
Rule 12-16	☐	☐	☐	☑
c) Be located on a geologic unit or soil that is unstable or that would become unstable as a result of the project, and potentially result in onsite or offsite landslide, lateral spreading, subsidence, liquefaction or collapse?				
Rule 11-18	☐	☐	☑	☐
Rule 12-16	☐	☐	☑	☐
d) Be located on expansive soil, as defined in Table 18-1-B of the Uniform Building Code (1994), creating substantial risks to life or property?				
Rule 11-18	☐	☐	☐	☑
Rule 12-16	☐	☐	☐	☑

Would the project:	Potentially Significant Impact	Less Than Significant Impact with Mitigation Incorporated	Less-than-Significant Impact	No Impact
e) Have soils incapable of adequately supporting the use of septic tanks or alternative wastewater disposal systems in areas where sewers are not available for the disposal of wastewater?				
Rule 11-18	☐	☐	☐	☑
Rule 12-16	☐	☐	☐	☑

Setting

The BAAQMD covers all of Alameda, Contra Costa, Marin, San Francisco, San Mateo, Santa Clara, and Napa Counties and portions of southwestern Solano and southern Sonoma Counties. The area of coverage is vast (about 5,600 square miles) so that land uses vary greatly and include commercial, industrial, residential, agricultural, and open space uses. The facilities affected by the rules are located primarily in commercial and industrial areas within the Bay Area.

The affected facilities are located in the natural region of California known as the Coast Ranges geomorphic province. The province is characterized by a series of northwest trending ridges and valleys controlled by tectonic folding and faulting, examples of which include the Suisun Bay, East Bay Hills, Briones Hills, Vaca Mountains, Napa Valley, and Diablo Ranges.

Regional basement rocks consist of the highly deformed Great Valley Sequence, which include massive beds of sandstone inter-fingered with siltstone and shale. Unconsolidated alluvial deposits, artificial fill, and estuarine deposits, (including Bay Mud) underlie the low-lying region along the margins of the Carquinez Straight and Suisun Bay. The estuarine sediments found along the shorelines of Solano County are soft, water-saturated mud, peat and loose sands. The organic, soft, clay-rich sediments along the San Francisco and San Pablo Bays are referred to locally as Bay Mud and can present a variety of engineering challenges due to inherent low strength, compressibility and saturated conditions. Landslides in the region occur in weak, easily weathered bedrock on relatively steep slopes.

The San Francisco Bay Area is a seismically active region, which is situated on a plate boundary marked by the San Andreas Fault System. Several northwest trending active and potentially active faults are included with this fault system. Under the Alquist-Priolo Earthquake Fault Zoning Act, Earthquake Fault Zones were established by the California Division of Mines and Geology along “active” faults, or faults along which surface rupture occurred in Holocene time (the last 11,000 years). In the Bay area, these faults include the San Andreas, Hayward, Rodgers Creek-Healdsburg, Concord-Green Valley, Greenville-Marsh Creek, Seal Cove/San Gregorio and West Napa faults. Other smaller faults in the region classified as potentially active include the Southampton and Franklin faults.

Ground movement intensity during an earthquake can vary depending on the overall magnitude, distance to the fault, focus of earthquake energy, and type of geological material. Areas that are underlain by bedrock tend to experience less ground shaking than those underlain by unconsolidated sediments such as artificial fill. Earthquake ground shaking may have secondary effects on certain foundation materials, including liquefaction, seismically induced settlement, and lateral spreading.

Regulatory Background

Construction is regulated by local City or County building codes and ordinances that regulate construction, grading, excavations, use of fill, and foundation work including type of materials, design, procedures, etc. which are intended to limit the probability of occurrence and the severity of consequences from geological hazards. Necessary permits, plan checks, and inspections are generally required.

All City or County General Plans include a Safety Element. The Element identifies seismic hazards and their location in order that they may be taken into account in the planning of future development. The California Building Code is the principle mechanism for protection against and relief from the danger of earthquakes and related events.

In addition, the Seismic Hazard Zone Mapping Act (Public Resources Code §§2690 – 2699.6) was passed by the California legislature in 1990 following the Loma Prieta earthquake. The act required that the California Division of Mines and Geology (DMG) develop maps that identify the areas of the state that require site specific investigation for earthquake-triggered landslides and/or potential liquefaction prior to permitting most urban developments. The act directs cities, counties, and state agencies to use the maps in their land use planning and permitting processes.

Local governments are responsible for implementing the requirements of the Seismic Hazards Mapping Act. The maps and guidelines are tools for local governments to use in establishing their land use management policies and in developing ordinances and review procedures that will reduce losses from ground failure during future earthquakes.

Discussion of Impacts

VI. a, c, and d).

Rule 11-18: The rule will not directly expose people or structures to earthquake faults, seismic shaking, seismic-related ground failure including liquefaction, landslides, mudslides or substantial soil erosion, as BAAQMD rules or regulations do not directly or indirectly result in construction of new structures. Some new structures, or structural modifications at existing affected facilities may occur as a result of installing control equipment or making process modifications. In any event, existing affected facilities or modifications to existing facilities would be required to comply with relevant California Building Code requirements in effect at the time of initial construction or modification of a structure.

New structures must be designed to comply with the California Building Code Zone 4 requirements since the Air District is located in a seismically active area. The local cities or counties are responsible for assuring that projects comply with the Uniform Building Code and can conduct inspections to ensure compliance. The California Building Code is considered to be a standard safeguard against major structural failures and loss of life. The goal of the Code is to provide structures that will: (1) resist minor earthquakes without damage; (2) resist moderate earthquakes without structural damage but with some non-structural damage; and (3) resist major earthquakes without collapse but with some structural and non-structural damage. The California Building Code bases seismic design on minimum lateral seismic forces ("ground shaking") and operates on the principle that providing appropriate foundations, among other aspects, helps to protect buildings from failure during earthquakes. The basic formulas used for the California Building Code seismic design require determination of the seismic zone and site coefficient, which represents the foundation conditions at the site.

Any potentially affected facilities that are located in areas where there has been historic occurrence of liquefaction, e.g., coastal zones, or existing conditions indicate a potential for liquefaction, including expansive or unconsolidated granular soils and a high water table, may have the potential for liquefaction induced impacts at the project sites. The California Building Code requirements consider liquefaction potential and establish more stringent requirements for building foundations in areas potentially subject to liquefaction. Therefore, compliance with the California Building Code requirements is expected to minimize the potential impacts associated with liquefaction. The issuance of building permits from the local cities or counties will assure compliance with the California Building Code requirements. Therefore, no significant impacts from liquefaction are expected.

Because facilities affected by any Air District control equipment requirements are typically located in industrial or commercial areas, which are not usually located near known geological hazards (e.g., landslide, mudflow, seiche, or volcanic hazards), no significant adverse geological impacts are expected. In addition, although refineries and possibly other facilities are located along the shoreline and may be affected by flooding from tsunamis, modifying existing equipment or installing new equipment to further control emissions from an existing facility will not expose people to new risks from tsunamis.

Rule 12-16: The petroleum refineries affected by Rule 12-16 already exist and operate within the confines of existing industrial facilities in the Bay Area. Construction activities could be required to install air pollution control equipment associated with complying with the refinery-wide emissions limits. Any substantial construction activities associated with new refinery equipment would occur within the confines of existing refineries and would be required to comply with the California Building Code. The California Building Code is considered to be a standard safeguard against major structural failures and loss of life. Any construction at industrial facilities regulated by the rule will be constructed in compliance with the California Building Code. The goal of the code is to provide structures that will: (1) resist minor earthquakes without damage; (2) resist moderate earthquakes without structural damage, but with some non-structural damage; and (3) resist major earthquakes without collapse, but with some structural and non-structural damage. The California Building Code bases seismic design on minimum lateral seismic forces ("ground shaking"). The California Building Code requirements operate on the principle that providing appropriate foundations, among other aspects, helps to protect buildings from failure during earthquakes. The basic formulas used for the California Building Code seismic design require determination of the seismic zone and site coefficient, which represent the foundation conditions at the site. Compliance with the California Building Code would minimize the impacts associated with existing geological hazards.

Any new development at the petroleum refineries affected by the rule would be required to obtain building permits, as applicable, for new foundations and structures at any site. The issuance of building permits from the local agency will assure compliance with the California Building Code, which include requirements for building within seismic hazard zones. No significant impacts from seismic hazards are expected since the construction of any new structures would be required to comply with the California Building Code.

Because facilities affected by any Air District control equipment requirements are typically located in industrial or commercial areas, which are not usually located near known geological hazards (e.g., landslide, mudflow, seiche, or volcanic hazards), no significant adverse geological impacts are expected. In addition, although refineries and possibly other facilities are located along the shoreline and may be affected by flooding from tsunamis, modifying existing equipment or installing new equipment to further control emissions from an existing facility will not expose people to new risks from tsunamis.

VI. b).

Rule 11-18: Although Rule 11-18 may require modifications at existing industrial or commercial facilities, such modifications are not expected to require substantial grading or construction activities. Any new air pollution control equipment is not expected to substantially increase the area subject to compaction since the subject areas would be limited in size and, typically, have already been graded or displaced in some way. Therefore, significant adverse soil erosion impacts are not anticipated from implementing Rule 11-18.

Rule 12-16: Any construction activities would be limited to the confines of existing refineries which are already graded and developed. Rule 12-16 is not expected to result in substantial soil erosion or the loss of topsoil as construction activities would be limited to areas that have been already been graded and developed, and adjacent to other existing refinery operations.

VI. e).

Rule 11-18: The CEQA environmental checklist includes a discussion of septic tanks and alternative wastewater disposal systems within the discussion of Geology and Soils. Therefore, a discussion of septic tanks and alternative septic systems is included herein for completeness. Septic tanks or other similar alternative wastewater disposal systems are typically associated with small residential projects in remote areas. The rule does not contain any requirements which generate construction of residential projects in remote areas. Rule 11-18 would only affect existing industrial or commercial facilities, which already are hooked up to appropriate sewerage facilities, and therefore no impacts on septic tanks or alternative wastewater disposal systems are expected.

Rule 12-16: Septic tanks or other similar alternative wastewater disposal systems are typically associated with small residential projects in remote areas. Rule 12-16 would only affect existing refineries that are already connected to appropriate wastewater facilities. Based on these considerations, septic tanks or other alternative wastewater disposal systems are not expected to be impacted by Rule 12-16.

Conclusions

Based upon the above considerations, significant adverse project-specific impacts to geology and soils are not expected to occur due to implementation of Rule 11-18 and 12-16 and, therefore, will not be further evaluated in the Draft EIR.

VII. GREENHOUSE GAS EMISSIONS.

Would the project:	Potentially Significant Impact	Less Than Significant Impact with Mitigation Incorporated	Less-than-Significant Impact	No Impact
a) Generate greenhouse gas emissions, either directly or indirectly, that may have a significant impact on the environment?				
Rule 11-18	☑	☐	☐	☐
Rule 12-16	☑	☐	☐	☐
b) Conflict with an applicable plan, policy or regulation adopted for the purpose of reducing the emissions of greenhouse gases?				
Rule 11-18	☐	☐	☑	☐
Rule 12-16	☑	☐	☐	☐

Setting

Global climate change refers to changes in average climatic conditions on the earth as a whole, including temperature, wind patterns, precipitation and storms. Global warming, a related concept, is the observed increase in the average temperature of the earth's surface and atmosphere. One identified cause of global warming is an increase of greenhouse gases (GHGs) in the atmosphere. The six major GHGs identified by the Kyoto Protocol are carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), sulfur hexafluoride (SF_6), haloalkanes (HFCs), and perfluorocarbons (PFCs). The GHGs absorb longwave radiant energy reflected by the earth, which warms the atmosphere. GHGs also radiate longwave radiation both upward to space and back down toward the surface of the earth. The downward part of this longwave radiation absorbed by the atmosphere is known as the "greenhouse effect." Some studies indicate that the potential effects of global climate change may include rising surface temperatures, loss in snow pack, sea level rise, more extreme heat days per year, and more drought years.

Events and activities, such as the industrial revolution and the increased combustion of fossil fuels (e.g., gasoline, diesel, coal, etc.), have heavily contributed to the increase in atmospheric levels of GHGs. Approximately 80 percent of GHG emissions in California are from fossil fuel combustion and over 70 percent of GHG emissions are carbon dioxide emissions (BAAQMD, 2010).

Regulatory Background

In response to growing scientific and political concern regarding global climate change, California has taken the initiative to address the state's greenhouse gas emissions. California has adopted the Global Warming Solutions Act of 2006, also known as AB 32, which requires the state to reduce its GHG emissions to 1990 levels by 2020. In addition, in 2005 Governor Schwarzenegger adopted Executive Order S-3-05, which commits to achieving an 80 percent reduction below 1990 levels by 2050. The

California Air Resources Board (CARB) has begun implementation of these mandates through adoption of regulatory requirements to reduce GHG emissions (among other agency implementation actions). Major sources of GHG emissions are under CARB's AB32 cap and trade program, which established a limit on GHG emissions for each source. GHG emissions over the limit require additional GHG emission reductions or purchase of GHG emission credits from sources that had excess emission credits.

Senate Bills 1078 and 107 and Executive Order S-14-08 (2008): SB 1078 (Chapter 516, Statutes of 2002) required retail sellers of electricity to provide at least 20 percent of their supply from renewable sources by 2017. SB 107 (Chapter 464, Statutes of 2006) changed the target date to 2010. In November 2008, then Governor Schwarzenegger signed EO S-14-08, which expands the state's Renewable Portfolio Standard to 33 percent renewable power by 2020. Governor Brown signed EO B-30-15 in 2015 in order to reduce GHG emissions by 40 percent below 1990 levels by 2030 to ensure California meets its target of reducing GHG emissions to 80 percent of 1990 levels by 2050.

The Clean Energy and Pollution Reduction Act of 2015, SB 350 (Chapter 547, Statutes of 2015) was approved by Governor Brown on October 7, 2015. SB 350 will (1) increase the standards of the California RPS program by requiring that the amount of electricity generated and sold to retail customers per year from eligible renewable energy resources be increased to 50 percent by December 31, 2030; (2) require the State Energy Resources Conservation and Development Commission to establish annual targets for statewide energy efficiency savings and demand reduction that will achieve a cumulative doubling of statewide energy efficiency savings in electricity and natural gas final end uses of retail customers by January 1, 2030; (3) provide for the evolution of the Independent System Operator (ISO) into a regional organization; and (4) require the state to reimburse local agencies and school districts for certain costs mandated by the state through procedures established by statutory provisions.

SB 862: In June 2014, SB 862 (Chapter 36, Statutes of 2014) established long-term funding programs from the Cap and Trade program for transit, sustainable communities and affordable housing, and high speed rail. SB 862 allocates 60 percent of ongoing Cap and Trade revenues, beginning in 2015–2016, to these programs. The remaining 40 percent is to be determined by future legislatures. A minimum of 25 percent of Cap and Trade dollars must go to projects that provide benefits to disadvantaged communities, and a minimum of 10 percent must go to projects located within those disadvantaged communities. In addition, this bill established the CalRecycle Greenhouse Gas Reduction Revolving Loan Program and Fund.

Most recently, SB 32 was signed into law in September 2016 and requires the California Air Resources Board (ARB) to ensure that statewide greenhouse gas emissions are reduced to 40% below the 1990 level by 2030. ARB is developing a 2030 Target Scoping Plan to implement this charge and expects to release a draft of the plan around the end of the year.

At the federal level, the U.S. EPA has adopted GHG emissions limits for new light-duty cars and trucks. This regulation of mobile sources has in turn triggered New Source Review and Title V permitting requirements for stationary sources. These requirements include using Best Available Control Technology to control emissions from major facilities. In addition, the U.S. EPA is also in the process of adopting New Source Performance Standards for major GHG source categories (currently limited to electric utility generating units).

The U.S. Congress passed "The Consolidated Appropriations Act of 2008" (HR 2764) in December 2007, which requires reporting of GHG data and other relevant information from large emission sources and suppliers in the United States. The Rule is referred to as 40 Code of Federal Regulations (CFR) 4 Part 98 - Greenhouse Gas Reporting Program (GHGRP). Facilities that emit 25,000 metric tonnes or more per year of GHGs are required to submit annual reports to U.S. EPA.

Discussion of Impacts

VII. a).

Rule 11-18: Rule 11-18 is designed to reduce the health risk associated with facilities that emit toxic air contaminants. There are several ways the risk associated with a facility can be reduced, which are outline in Table 2. 2. Included under this listing are:

- Enclosures and collection systems for particulate matter TACs;
- Filtration for toxic aerosols and particulate matter;
- Carbon adsorption and adsorption-oxidation systems for VOCs;
- Chemical absorption for VOCs;
- Thermal and catalytic oxidation for inorganic gases (such as hydrogen sulfide) and organic compounds; and
- Combination systems for the control of halogenated VOCs;

Each of the control options listed above has associated with it the potential to increase use of fuels, for combustion sources (e.g., electricity, natural gas, or refinery fuel gas), potentially generating additional greenhouse gas emission impacts. Construction activities for new and modified control devices may also result in GHG emissions. Therefore, GHG impacts from Rule 11-18 will be evaluated in the Draft EIR.

Rule 12-16: Rule 12-16 is designed to limit facility-wide emissions of GHGs and three criteria pollutants from the five petroleum refineries located within the jurisdiction of the BAAQMD. Rule 12-16 sets limits on the amount of these pollutants each refinery could emit annually and could require the installation of additional air pollution control equipment or modification of refinery operations to ensure each refinery stays within those limits. The rule could require new construction activities and the operation of new/modified refinery equipment. While, the goal of Rule 12-16 is to minimize overall refinery emissions, however, refinery modifications could result in the increased use of fuel for combustions sources (e.g., electricity, natural gas, or refinery fuel gas), potentially generating additional greenhouse gas emission impacts. As a result, the impacts of this rule on greenhouse gases will be further evaluated in the Draft EIR.

VII. b).

Rule 11-18: Rule 11-18 would require facilities that pose a health risk in excess of a risk action level either reduce risks below the thresholds or apply TBARCT. However, these requirements would not conflict with any efforts by the state or the Air District to reduce GHG emissions. Because no potential conflicts on GHG plans, policies or regulations were identified, this topic will not be evaluated in the Draft EIR for Rule 11-18.

Rule 12-16: As written, Rule 12-16 would have a direct impact on GHG emissions from all Bay Area refineries by setting an upper limit on the amount of GHGs each refinery can emit. The AB 32 Cap and Trade program allows covered facilities to buy and sell GHG emissions credits. Under Rule 12-16, Bay Area refineries would not be allowed to purchase GHG credits that would allow an increase in excess of the refinery-wide GHG limit. So, theoretically, under the Cap and Trade program, the GHG emissions of an individual refinery could increase while the overall goals of the program are being met. Because the GHG limits of Rule 12-16 could conflict with this aspect of the ARB's AB32 cap and trade program, the potential impacts of this conflict will be evaluated in the Draft EIR.

Conclusions

Based upon the above considerations, the potential GHG emissions associated with Rules 11-18 and 12-16 will be evaluated in the Draft EIR. No significant impacts on GHG plans, policies, or regulations were identified for Rule 11-18, so this topic will not be addressed further in the Draft EIR for Rule 11-18. However, potentially significant impacts were identified for Rule 12-16, and therefore this topic will be addressed in the Draft EIR.

VIII. HAZARDS AND HAZARDOUS MATERIALS.

Would the project:	Potentially Significant Impact	Less Than Significant Impact with Mitigation Incorporated	Less-than-Significant Impact	No Impact
a) Create a significant hazard to the public or the environment through the routine transport, use, or disposal of hazardous materials?				
Rule 11-18	☐	☐	☑	☐
Rule 12-16	☑	☐	☐	☐
b) Create a significant hazard to the public or the environment through reasonably foreseeable upset and accident conditions involving the release of hazardous materials into the environment?				
Rule 11-18	☐	☐	☑	☐
Rule 12-16	☑	☐	☐	☐
c) Emit hazardous emissions or involve handling hazardous or acutely hazardous materials, substances, or waste within one-quarter mile of an existing or proposed school?				
Rule 11-18	☐	☐	☐	☑
Rule 12-16	☑	☐	☐	☐
d) Be located on a site that is included on a list of hazardous materials sites compiled pursuant to Government Code § 65962.5 and, as a result, would it create a significant hazard to the public or the environment?				
Rule 11-18	☐	☐	☑	☐
Rule 12-16	☐	☐	☐	☑
e) For a project located within an airport land use plan or, where such a plan has not been adopted, within two miles of a public airport or public use airport, and result in a safety hazard for people residing or working in the project area?				
Rule 11-18	☐	☐	☐	☑
Rule 12-16	☐	☐	☐	☑
f) For a project within the vicinity of a private airstrip, would the project result in a safety hazard for people residing or working in the project area?				
Rule 11-18	☐	☐	☐	☑
Rule 12-16	☐	☐	☐	☑
g) Impair implementation of or physically interfere with an adopted emergency response plan or emergency evacuation plan?				
Rule 11-18	☐	☐	☐	☑
Rule 12-16	☐	☐	☐	☑

Would the project:	Potentially Significant Impact	Less Than Significant Impact with Mitigation Incorporated	Less-than-Significant Impact	No Impact
h) Expose people or structures to a significant risk of loss, injury or death involving wildland fires, including where wildlands are adjacent to urbanized areas or where residences are intermixed with wildlands?				
Rule 11-18	☐	☐	☑	☐
Rule 12-16	☐	☐	☐	☑

Setting

The BAAQMD covers all of Alameda, Contra Costa, Marin, Napa, San Francisco, San Mateo, and Santa Clara Counties, and potions of western Solano and southern Sonoma Counties. Because the area of coverage is vast (approximately 5,600 square miles), land uses vary greatly and include commercial, industrial, residential, and agricultural uses.

Facilities and operations within the Air District handle and process substantial quantities of flammable materials and acutely toxic substances. Accidents involving these substances can result in worker or public exposure to fire, heat, blast from an explosion, or airborne exposure to hazardous substances.

Fires can expose the public or workers to heat. The heat decreases rapidly with distance from the flame and therefore poses a greater risk to workers at specific facilities where flammable materials and toxic substances are handled than to the public. Explosions can generate a shock wave, but the risks from explosion also decrease with distance. Airborne releases of hazardous materials may affect workers or the public, and the risks depend upon the location of the release, the hazards associated with the material, the winds at the time of the release, and the proximity of receptors.

For all facilities and operations handling flammable materials and toxic substances, risks to the public are reduced if there is a buffer zone between process units and residences or if prevailing winds blow away from residences. Thus, the risks posed by operations at a given facility or operation are unique and determined by a variety of factors.

Rule 11-18 has the potential to affect a large variety of facilities that emit toxic pollutants, including petroleum refineries, chemical plants, foundries, a cement kiln, gasoline dispensing facilities, data centers, hospitals, crematoria, residential buildings, fire stations, schools and universities, military installations, etc. Rule 12-16 would affect petroleum refineries that handle and process large quantities of flammable, hazardous, and acutely hazardous materials. Accidents involving these substances can result in worker or public exposure to fire, heat, blast from an explosion, or airborne exposure to hazardous substances.

The potential hazards associated with handling such materials are a function of the materials being processed, processing systems, and procedures used to operate and maintain the facilities where they exist. The hazards that are likely to exist are identified by the physical and chemical properties of the materials being handled and their process conditions, including the following events.

- **Toxic gas clouds:** Toxic gas clouds are releases of volatile chemicals (e.g., anhydrous ammonia, chlorine, and hydrogen sulfide) that could form a cloud and migrate off-site, thus exposing the public. "Worst-case" conditions tend to arise when very low wind speeds coincide with an accidental release, which can allow the chemicals to accumulate rather than disperse.

- **Torch fires (gas and liquefied gas releases), flash fires (liquefied gas releases), pool fires, and vapor cloud explosions (gas and liquefied gas releases):** The rupture of a storage tank or vessel containing a flammable gaseous material (like propane), without immediate ignition, can result in a vapor cloud explosion. The "worst-case" upset would be a release that produces a large aerosol cloud with flammable properties. If the flammable cloud does not ignite after dispersion, the cloud would simply dissipate. If the flammable cloud were to ignite during the release, a flash fire or vapor cloud explosion could occur. If the flammable cloud were to ignite immediately upon release, a torch fire would ensue.

- **Thermal Radiation:** Thermal radiation is the heat generated by a fire and the potential impacts associated with exposure. Exposure to thermal radiation would result in burns, the severity of which would depend on the intensity of the fire, the duration of exposure, and the distance of an individual to the fire.

- **Explosion/Overpressure:** Process vessels containing flammable explosive vapors and potential ignition sources are present at many types of industrial facilities. Explosions may occur if the flammable/explosive vapors came into contact with an ignition source. An explosion could cause impacts to individuals and structures in the area due to overpressure.

For all affected facilities, risks to the public are reduced if there is a buffer zone between industrial processes and residences or other sensitive land uses, or the prevailing wind blows away from residential areas and other sensitive land uses. The risks posed by operations at each facility are unique and determined by a variety of factors. The areas affected by the rules are typically located in industrial areas.

Regulatory Background

There are many federal and state rules and regulations that facilities handling hazardous materials must comply with which serve to minimize the potential impacts associated with hazards at these facilities.

Under the Occupational Safety and Health Administration (OSHA) regulations [29 Code of Federal Regulations (CFR) Part 1910], facilities which use, store, manufacture, handle, process, or move highly hazardous materials must prepare a fire prevention plan. In addition, 29 CFR Part 1910.119, Process Safety Management (PSM) of Highly Hazardous Chemicals, and Title 8 of the California Code of Regulations, General Industry Safety Order §5189, specify required prevention program elements to protect workers at facilities that handle toxic, flammable, reactive, or explosive materials.

Section 112 (r) of the Clean Air Act Amendments of 1990 [42 U.S.C. 7401 et. Seq.] and Article 2, Chapter 6.95 of the California Health and Safety Code require facilities that handle listed regulated substances to develop Risk Management Programs (RMPs) to prevent accidental releases of these substances, U.S. EPA regulations are set forth in 40 CFR Part 68. In California, the California Accidental Release Prevention (CalARP) Program regulation (CCR Title 19, Division 2, Chapter 4.5) was issued by the Governor's Office of Emergency Services (OES). RMPs consist of three main elements: a hazard assessment that includes off-site consequences analyses and a five-year accident history, a prevention program, and an emergency response program. California is proposing modifications to the CalARP Program along with the state's PSM program in response to an accident at the Chevron Richmond Refinery. The regulations were released for public comment on July 15, 2016 and the public comment period closes on September 15, 2016.

Affected facilities that store materials are required to have a Spill Prevention Control and Countermeasures (SPCC) Plan per the requirements of 40 Code of Federal Regulations, §112. The SPCC is designed to prevent spills from on-site facilities (e.g., storage tanks) and includes requirements for secondary containment, provides emergency response procedures, establishes training requirements, and so forth.

The Hazardous Materials Transportation (HMT) Act is the federal legislation that regulates transportation of hazardous materials. The primary regulatory authorities are the U.S. Department of Transportation, the Federal Highway Administration, and the Federal Railroad Administration. The HMT Act requires that carriers report accidental releases of hazardous materials to the Department of Transportation at the earliest practical moment (49 CFR Subchapter C). The California Department of Transportation (Caltrans) sets standards for trucks in California. The regulations are enforced by the California Highway Patrol.

California Assembly Bill 2185 requires local agencies to regulate the storage and handling of hazardous materials and requires development of a business plan to mitigate the release of hazardous materials. Businesses that handle any of the specified hazardous materials must submit to government agencies (i.e., fire departments), an inventory of the hazardous materials, an emergency response plan, and an employee training program. The information in the business plan can then be used in the event of an emergency to determine the appropriate response action, the need for public notification, and the need for evacuation.

Contra Costa County has adopted an industrial safety ordinance that addresses the human factors that lead to accidents. The ordinance requires stationary sources to develop a written human factors program that considers human factors as part of process hazards analyses, incident investigations, training, operating procedures, among others.

Discussion of Impacts

VIII. a, b, and c).

Rule 11-18: Rule 11-18 has the potential to create direct or indirect hazard impacts associated with affected facility modifications employed to reduce risks. The rule is designed to reduce health risk associated with the emissions of TACs from existing stationary sources in the Bay Area. The rule is not expected to require substantial new development. Any new air pollution control equipment or enclosures would be expected to occur within existing commercial or industrial facilities. The rule is expected to increase the control and capture of TACs, thus limiting TAC emissions and exposure to TACs and ultimately, reduce health risks.

Facility modifications associated with the rule are largely expected to include limiting throughput or hours of operations; increased use of diesel particulate filters; additional enclosures and bag houses, and thermal oxidizers or carbon adsorption systems. The hazards associated with the use of these types of air pollution control equipment and systems are minimal.

- Limiting throughput or hours of operations would not result in increased hazards as no new equipment, hazardous materials uses, or hazards would be generated.
- Diesel particulate filters and baghouses are not expected to result in additional hazards as they would simply filter exhaust.

Operation of carbon adsorption systems has potential hazards associated with the desorption cycle when there is minor risk for explosion or release of VOC into the atmosphere. Carbon adsorption systems may also represent a fire risk during operation when carbon particles are saturated with volatile organic compounds. The potential hazard impacts would depend on the flammability of the material, concentration of VOC adsorbed into the activated carbon, ambient oxygen levels, characteristics of the carbon adsorption system, and the operating conditions. Carbon adsorption units would concentrate hazardous organic compound into the spent carbon, requiring recycling or disposal.

The risk of explosion or release of VOC from carbon adsorption systems is not expected to be significant. The engineering specifications for a carbon adsorption unit are typically designed to operate within an acceptable range of temperatures for the carbon bed. Good engineering practice means this range of temperatures should not exceed the lower explosive limit (LEL) of the compound(s) being adsorbed. There is little risk of fire if the LEL is not exceeded.

Oxidation systems can be susceptible to compressor failure and flame flashbacks, particularly during startup and shutdown. As a result, oxidation systems could pose potential hazard risks primarily to workers or to a lesser extent the public in the event of explosions or fires. Oxidation systems historically have a good safety record when operated properly according to the manufacturers' instruction. Proper tune-up and maintenance is also important and necessary to avoid failures or explosions. When installed, operated, and maintained properly, oxidation systems are not expected to create fire or explosion hazards to workers or the public in general.

In addition to following good engineering practice for both oxidization systems, thermal oxidizers and carbon adsorption systems, Health and Safety Code §25506 specifically requires all businesses handling hazardous materials to submit a business emergency response plan to assist local administering agencies in the event of an emergency release or threatened release of a hazardous material. Business emergency response plans generally require the following:

- Types and quantities of hazardous materials used and their locations;
- Training programs for employees including safe handling of hazardous materials and emergency response procedures and resources.

- Procedures for emergency response notification;
- Proper use of emergency equipment;
- Procedures to mitigate a release or threatened release of hazardous materials and measures to minimize potential harm or damage to individuals, property, or the environment; and
- Evacuation plans and procedures.

Hazardous materials are expected to be used in compliance with established OSHA or Cal/OSHA regulations and procedures, including providing adequate ventilation, using recommended personal protective equipment and clothing, posting appropriate signs and warnings, and providing adequate worker health and safety training. The exposure of employees is regulated by Cal-OSHA in Title 8 of the CCR. Specifically, 8 CCR 5155 establishes permissible exposure levels (PELs) and short-term exposure levels (STELs) for various chemicals. These requirements apply to all employees. The PELs and STELs establish levels below which no adverse health effects are expected. These requirements protect the health and safety of the workers, as well as the nearby population including sensitive receptors.

In general, all local jurisdictions and all facilities using a minimum amount of hazardous materials are required to formulate detailed contingency plans to eliminate, or at least minimize, the possibility and effect of fires, explosion, or spills. In conjunction with the California Office of Emergency Services, local jurisdictions have enacted ordinances that set standards for area and business emergency response plans. These requirements include immediate notification, mitigation of an actual or threatened release of a hazardous material, and evacuation of the emergency area.

The above regulations provide comprehensive measures to reduce hazards of explosive or otherwise hazardous materials. Compliance with these and other federal, state and local regulations and proper operation and maintenance of equipment should ensure the potential for explosions or accidental releases of hazardous materials is not significant. Therefore, the rule is not expected to create a significant hazard to the public or environment.

Schools may be located within a quarter mile of commercial, industrial or institutional facilities affected by Rule 11-18. It would be expected that these facilities are taking the appropriate and required actions to ensure proper handling or hazardous materials, substances or wastes near school sites. The rule would not generate hazardous emissions, handling of hazardous or acutely hazardous materials, substances or waste within one-quarter mile of an existing or proposed school. Rather, the rule would be more likely to control TACs from existing facilities near school sites. Therefore, no increase in hazardous emissions from implementation of Rule 11-18 would be expected.

Rule 12-16: Rule 12-16 has the potential to create direct or indirect hazard impacts associated with refinery modifications. The requirement to limit refinery emissions of certain pollutants could result in additional construction activities at the refineries, refinery modifications, and/or changes in refinery operations. Some refinery modifications and changes in operations could generate additional hazard impacts. In particular, NOx emission reduction measures could result in the increased use of ammonia, which is a hazardous material, in selective catalytic reduction (SCR) units. These potential hazard impacts will be further evaluated in the Draft EIR.

VIII. d). Government Code §65962.5 requires creation of lists of facilities that may be subject to Resource Conservation and Recovery Act (RCRA) permits or site cleanup activities.

Rule 11-18: It is not known if the affected commercial or industrial facilities are located on the hazardous materials sites list pursuant to Government Code §65962.5. However, the rule is expected to increase the control of TAC emissions and would not interfere with site cleanup activities or create additional site contamination, and would not create a significant hazard to the public or environment.

Rule 12-16: The refineries affected by the rule may be located on the hazardous materials sites list pursuant to Government Code §65962.5. The refineries would be required to manage any and all hazardous materials in accordance with federal, state and local regulations. Rule 12-16 is not expected to interfere with site cleanup activities or create additional site contamination. Therefore, this topic is less than significant and will not be further evaluated in the Draft EIR.

VIII. e and f).

Rules 11-18 and 12-16: Neither rule is expected to result in a safety hazard for people residing or working within two miles or a public airport or air strip. No impacts on airports or airport land use plans are anticipated from the rules, which are expected to increase the control of criteria and toxic pollutant emissions. Modifications are expected to be confined to the existing commercial or industrial land uses. Therefore, no significant adverse impacts on an airport land use plan or on a private air strip are expected.

VIII. g). Rules 11-18 and 12-16: No impacts on emergency response plans are anticipated from Rule 11-18 and Rule 12-16 that would apply to existing facilities (including refineries, etc.). The facilities affected by the rules already exist and operate within the confines of existing industrial facilities. The rules neither require, nor are likely to result in, activities that would impact any emergency response plan. The existing facilities affected by the rules already store and transport hazards materials, so emergency response plans already include hazards associated with existing refinery operations. The rules are not expected to require any changes in emergency response planning. Therefore, no significant adverse impacts on emergency response plans are expected.

VIII. h). Rules 11-18 and 12-16: No increase in hazards associated with wildfires is anticipated from Rule 11-18 or Rule 12-16. The existing facilities (including petroleum refineries, etc.) affected by the rules already exist and operate within the confines of existing commercial or industrial facilities. Native vegetation has been removed from the operating portions of the affected facilities to minimize fire hazards. Neither Rule 11-18 nor Rule 12-16 is expected to increase the risk of hazards associated with wildland fires in general and specifically in areas with flammable materials. Therefore, neither Rule 11-18 nor Rule 12-16 would expose people or structures to significant risk of loss, injury or death involving wildland fires.

Conclusions

Rule 11-18: Based upon these considerations, no significant adverse hazards and hazardous materials impacts are expected from the implementation of Rule 11-18.

Rule 12-16: Based upon the above considerations, the potential refinery hazards that may be introduced due to compliance with Rule 12-16 will be evaluated in the Draft EIR (VIII. a, b, and c). No significant hazard impacts on sites listed pursuant to Government Code §65962.5, public airports or airstrips, emergency response plans or hazards associated with wildfires are expected, and these topics will not be addressed further in the Draft EIR.

IX. HYDROLOGY AND WATER QUALITY.

Would the project:	Potentially Significant Impact	Less Than Significant Impact with Mitigation Incorporated	Less-than-Significant Impact	No Impact
a) Violate any water quality standards or waste discharge requirements?				
Rule 11-18	☐	☐	☑	☐
Rule 12-16	☑	☐	☐	☐
b) Substantially deplete groundwater supplies or interfere substantially with groundwater recharge such that there would be a net deficit in aquifer volume or a lowering of the local groundwater table level (e.g. the production rate of pre-existing nearby wells would drop to a level that would not support existing land uses or planned uses for which permits have been granted)?				
Rule 11-18	☐	☐	☑	☐
Rule 12-16	☑	☐	☐	☐
c) Substantially alter the existing drainage pattern of the site or area, including through alteration of the course of a stream or river, in a manner that would result in substantial erosion or siltation onsite or offsite?				
Rule 11-18	☐	☐	☐	☑
Rule 12-16	☐	☐	☐	☑
d) Substantially alter the existing drainage pattern of the site or area, including through the alteration of the course of a stream or river, or substantially increase the rate or amount of surface runoff in a manner that would result in flooding onsite or offsite?				
Rule 11-18	☐	☐	☐	☑
Rule 12-16	☐	☐	☐	☑
e) Create or contribute runoff water that would exceed the capacity of existing or planned stormwater drainage systems or provide substantial additional sources of polluted runoff?				
Rule 11-18	☐	☐	☐	☑
Rule 12-16	☐	☐	☐	☑
f) Otherwise substantially degrade water quality?				
Rule 11-18	☐	☐	☑	☐
Rule 12-16	☑	☐	☐	☐

Would the project:	Potentially Significant Impact	Less Than Significant Impact with Mitigation Incorporated	Less-than-Significant Impact	No Impact
g) Place housing within a 100-year flood hazard area, as mapped on a federal Flood Hazard Boundary or Flood Insurance Rate Map or other flood hazard delineation map?				
Rule 11-18	☐	☐	☐	☑
Rule 12-16	☐	☐	☐	☑
h) Place within a 100-year flood hazard area structures that would impede or redirect flood flows				
Rule 11-18	☐	☐	☐	☑
Rule 12-16	☐	☐	☐	☑
i) Expose people or structures to a significant risk of loss, injury or death involving flooding, including flooding as a result of the failure of a levee or dam?				
Rule 11-18	☐	☐	☐	☑
Rule 12-16	☐	☐	☐	☑
j) Inundation by seiche, tsunami, or mudflow?				
Rule 11-18	☐	☐	☐	☑
Rule 12-16	☐	☐	☐	☑

Setting

The BAAQMD covers all of Alameda, Contra Costa, Marin, San Francisco, San Mateo, Santa Clara, and Napa Counties and portions of southwestern Solano and southern Sonoma Counties. The area of coverage is vast (about 5,600 square miles), so that land uses and affected environment vary substantially throughout the area and include commercial, industrial, residential, agricultural, and open space uses.

The facilities affected by the rule are located within all counties under the jurisdiction of the BAAQMD. Affected areas are generally surrounded by other industrial or commercial facilities. Reservoirs and drainage streams are located throughout the area and discharge into the Bays. Marshlands incised with numerous winding tidal channels containing brackish water are located throughout the Bay Area.

The affected areas are located within the San Francisco Bay Area Hydrologic Basin. The primary regional groundwater water-bearing formations include the recent and Pleistocene (up to two million years old) alluvial deposits and the Pleistocene Huichica formation. Salinity within the unconfined alluvium appears to increase with depth to at least 300 feet. Water of the Huichica formation tends to be soft and relatively high in bicarbonate, although usable for domestic and irrigation needs.

Regulatory Background

The Federal Clean Water Act of 1972 primarily establishes regulations for pollutant discharges into surface waters in order to protect and maintain the quality and integrity of the nation's waters. This Act requires industries that discharge wastewater to municipal sewer systems to meet pretreatment standards. The regulations authorize the U.S. EPA to set the pretreatment standards. The regulations also allow the local treatment plants to set more stringent wastewater discharge requirements, if necessary, to meet local conditions.

The 1987 amendments to the Clean Water Act enabled the U.S. EPA to regulate, under the National Pollutant Discharge Elimination System (NPDES) program, discharges from industries and large municipal sewer systems. The U.S. EPA set initial permit application requirements in 1990. The State of California, through the State Water Resources Control Board, has authority to issue NPDES permits, which meet U.S. EPA requirements, to specified industries.

The Porter-Cologne Water Quality Act is California's primary water quality control law. It implements the state's responsibilities under the Federal Clean Water Act but also establishes state wastewater discharge requirements. The Regional Water Quality Control Boards (RWQCB) administer the state requirements as specified under the Porter-Cologne Water Quality Act, which include storm water discharge permits. The water quality in the Bay Area is under the jurisdiction of the San Francisco Bay Regional Water Quality Control Board.

In response to the Federal Act, the State Water Resources Control Board adopted the State Water Resources Control Plan for the San Francisco Bay/Sacramento-San Joaquin Delta Estuary in 2006. San Francisco Bay and its constituent parts, including Carquinez Strait and Suisun Bay, are considered to be enclosed bays (indentations along the coast that enclose an area of oceanic water within distinct headlands or harbors). The Plan consists of: (1) beneficial uses to be protected; (2) water quality objectives for the reasonable protection of beneficial uses; and (3) a program of implementation for achieving the water quality objectives. Together, the beneficial uses and the water quality objectives established to reasonably protect the beneficial uses are called water quality standards under the terminology of the federal Clean Water Act. The beneficial uses of the Carquinez Strait that must be protected include: municipal and domestic water supply systems, industrial service supply systems, agricultural supply systems, ground water recharge, navigation, water contact and non-contact recreation, shell fish harvesting, commercial and sport fishing, cold freshwater habitat, migration of aquatic organisms, spawning reproduction and early development, wildlife habitat, estuarine habitat, and preservation of rare, threatened. and endangered species.

Discussion of Impacts

IX. a, b, and f).

Rule 11-18: The rule is designed to reduce risk from existing stationary sources located throughout the Bay Area. Potential risk reduction measures include measures that would limit emissions of TACs. The rule is not expected to require any new development. Modifications are expected to be limited to existing commercial or industrial facilities. Physical changes are expected to be limited to new air pollution control equipment and construction of enclosures. No significant increase in wastewater discharge is expected from the project, and therefore no impacts on water quality resources are anticipated from the rule.

Minor construction may be necessary to install control systems. Construction would likely require a couple of pieces of off-road equipment, medium-duty truck trips to deliver equipment, and a small construction crew. The construction of enclosures may require some grading and foundations work. Grading and foundation work is not expected to last more than one week per project, therefore, minimal water will be required for dust mitigation. No wet gas scrubbers are expected as a result of the rule. All existing and new facilities will still be required to have applicable wastewater discharge permits and storm water pollution prevention plans (SWPPP).

No significant increase in water use is expected as a result of the rule. The Air District anticipates that facilities will implement various control measures, but no wet gas scrubbers are expected. Thus, water concerns will be limited to construction, which is expected to involve minor construction activities within existing facilities or buildings. Minor water use for construction purposes will not substantially increase water demand or interfere with groundwater recharge or cause any notable change in the groundwater table level.

Rule 12-16: Rule 12-16 could require the installation of additional air pollution control equipment or modify refinery operations. The rule could require new construction activities and the operation of new/modified refinery equipment. The goal of Rule 12-16 is to limit overall refinery emissions of certain pollutants, however, refinery modifications could result in the increased use of water. For example, control measures for particulate matter and/or SOx emissions could require additional water use and wastewater discharge from devices like wet gas scrubbers. The potential increase and water use and the potential to deplete groundwater supplies will be evaluated in the Draft EIR.

IX. c, d, and e).

Rule 11-18: The rule does not have the potential to substantially increase the area subject to runoff since the construction activities are expected to be limited in size and would be located primarily within existing facilities that have already been graded. Additionally, facilities are typically expected to develop a SWPPP to address storm water impacts. Rule 11-18 is also not expected to substantially alter the existing drainage or drainage patterns, result in erosion or siltation, alter the course of a stream or river, or substantially increase the rate or amount of surface runoff in a manner that would result in flooding onsite or offsite as there will be no major construction or significant water use. Therefore, no significant adverse impacts to storm water runoff or existing drainage patterns are expected as a result of the rule.

Rule 12-16: Rule 12-16 would limit the emissions of certain air pollutant and could require the installation of additional air pollution control equipment or modify refinery operations if those thresholds are exceeded. The rule does not have the potential to substantially increase the area subject to runoff since the construction activities are expected to be limited in size and would be located within existing refineries that have already been graded and developed. In addition, storm water drainage within refineries has been controlled and construction activities are not expected to alter the storm water drainage within the refineries. Therefore, the rule is not expected to substantially alter the existing drainage or drainage patterns, result in erosion or siltation, alter the course of a stream or river, or substantially increase the rate or amount of surface runoff in a manner that would result in flooding onsite or offsite. Additionally, the rule is not expected to create or contribute to runoff water that would exceed the capacity of existing or planned stormwater drainage systems or provide substantial additional sources of contaminated runoff. Therefore, no significant adverse impacts to storm water runoff are expected, and it will not be further evaluated in the Draft EIR.

IX. g, h, i, and j): Rules 11-18 and 12-16: Neither of the rules include the construction of new or relocation of existing housing or other types of facilities and, as such, would not require the placement of housing or other structures within a 100-year flood hazard area. (See also XIII "Population and Housing"). As a result, the rules would not be expected to create or substantially increase risks from flooding; expose people or structures to significant risk of loss, injury or death involving flooding; or increase existing risks, if any, of inundation by seiche, tsunami, or mudflow. Consequently, this topic will not be evaluated further in the Draft EIR.

Conclusions

Rule 11-18: Based upon these considerations, no significant adverse impacts to hydrology and water quality are expected from the adoption of the rule.

Rule 12-16: The potential increase in water use and the potential to deplete groundwater supplies will be evaluated in the Draft EIR. No significant adverse water quality impacts were identified for stormwater runoff, flood hazards, or inundation hazards and these topics will not be addressed in the Draft EIR.

X. LAND USE AND PLANNING.

Would the project:	Potentially Significant Impact	Less Than Significant Impact with Mitigation Incorporated	Less-than-Significant Impact	No Impact
a) Physically divide an established community?				
Rule 11-18	☐	☐	☐	☑
Rule 12-16	☐	☐	☐	☑
b) Conflict with any applicable land use plan, policy, or regulation of an agency with jurisdiction over the project (including, but not limited to a general plan, specific plan, local coastal program or zoning ordinance) adopted for the purpose of avoiding or mitigating an environmental effect?				
Rule 11-18	☐	☐	☐	☑
Rule 12-16	☐	☐	☐	☑
c) Conflict with any applicable habitat conservation plan or natural community conservation plan?				
Rule 11-18	☐	☐	☐	☑
Rule 12-16	☐	☐	☐	☑

Setting

The BAAQMD covers all of Alameda, Contra Costa, Marin, San Francisco, San Mateo, Santa Clara, and Napa Counties and portions of southwestern Solano and southern Sonoma Counties. The area of coverage is vast (about 5,600 square miles), so that land uses vary greatly and include commercial, industrial, residential, agricultural, and open space uses. The facilities affected by the rules are primarily located in commercial and industrial areas throughout the Bay Area.

Regulatory Background

Land uses are generally protected and regulated by the City and/or County General Plans through land use and zoning requirements.

Discussion of Impacts

X. a, b, and c)

Rule 11-18: The rule is designed to reduce risk from existing stationary sources located throughout the Bay Area. Potential risk reduction measures include measures that would limit emissions of TACs. The rule does not include any components that would require major modifications to existing commercial or industrial facilities and therefore the rule would not result in impacts that would physically divide an established community or generate additional development.

The rule is not expected to require any new substantial construction or development. New or modified pollution control equipment or enclosures would be located within existing commercial or industrial facilities. Construction activities would be limited to the confines of existing facilities which are zoned for commercial or industrial land use. Modifications to equipment would be limited to the confines of existing facilities and are not expected to affect adjacent land uses, divide an established community, conflict with any applicable land use plan or policy or conflict with any habitat conservation plan.

Rule 12-16: Construction activities could also be required to install air pollution control equipment associated with compliance with Rule 12-16. Any substantial construction activities associated with new refinery equipment would occur within the confines of existing refineries. The land use within the refineries is typically zoned for heavy industrial uses. Land uses surrounding the refineries can vary considerably and include industrial areas, commercial areas, open space, and residential areas. Construction activities would be limited to the confines of the refineries. The installation of air monitors or air pollution control equipment would not change or impact existing land uses.

Conclusions

Based upon the above considerations, significant adverse project-specific impacts to land use and planning are not expected to occur due to implementation of either Rule 11-18 or Rule 12-16 and, therefore, will not be further evaluated in the Draft EIR.

XI. MINERAL RESOURCES.

Would the project:	Potentially Significant Impact	Less Than Significant Impact with Mitigation Incorporated	Less-than-Significant Impact	No Impact
a) Result in the loss of availability of a known mineral resource that would be of value to the region and the residents of the state?				
Rule 11-18	☐	☐	☐	☑
Rule 12-16	☐	☐	☐	☑
b) Result in the loss of availability of a locally important mineral resource recovery site delineated on a local general plan, specific plan, or other land use plan?				
Rule 11-18	☐	☐	☐	☑
Rule 12-16	☐	☐	☐	☑

Setting

The BAAQMD covers all of Alameda, Contra Costa, Marin, San Francisco, San Mateo, Santa Clara, and Napa Counties and portions of southwestern Solano and southern Sonoma Counties. The area of coverage is vast (about 5,600 square miles) so that land uses and the affected environment vary greatly throughout the area. The facilities affected by the Rules 11-18 and 12-16 are primarily located in commercial and industrial areas within the Bay Area.

Regulatory Background

Mineral resources are generally protected and regulated by the City and/or County General Plans through land use and zoning requirements.

Discussion of Impacts

XI. a, and b).

Rule 11-18: Rule 11-18 is designed to reduce risk from existing stationary sources located throughout the Bay Area. Potential risk reduction measures include measures that would limit emissions of TACs. The rule is not associated with any action that would result in the loss of availability of a known mineral resource that would be of value to the region and the residents of the state, or of a locally important mineral resource recovery site delineated on a local general plan, specific plan or other land use plan. Therefore, no impacts on mineral resources are expected.

Rule 12-16: Rule 12-16 would limit the emissions of certain air pollutant and could require the installation of additional air pollution control equipment or modify refinery operations if those thresholds are exceeded. The rule is not associated with any action that would result in the loss of availability of a known mineral resource that would be of value to the region and the residents of the state, or of a locally important mineral resource recovery site delineated on a local general plan, specific plan or other land use plan. Therefore, no impacts on mineral resources are expected.

Conclusions

Based upon the above considerations, significant adverse project-specific impacts to mineral resources are not expected to occur due to implementation of either Rule 11-18 or Rule 12-16 and, therefore, will not be further evaluated in the Draft EIR.

XII. NOISE.

Would the project:	Potentially Significant Impact	Less Than Significant Impact with Mitigation Incorporated	Less-than-Significant Impact	No Impact
a) Exposure of persons to or generate noise levels in excess of standards established in the local general plan or noise ordinance, or applicable standards of other agencies?				
Rule 11-18	☐	☐	☑	☐
Rule 12-16	☐	☐	☑	☐
b) Exposure of persons to or generation of excessive groundborne vibration or groundborne noise levels?				
Rule 11-18	☐	☐	☑	☐
Rule 12-16	☐	☐	☑	☐
c) A substantial permanent increase in ambient noise levels in the project vicinity above levels existing without the project?				
Rule 11-18	☐	☐	☑	☐
Rule 12-16	☐	☐	☑	☐
d) A substantial temporary or periodic increase in ambient noise levels in the project vicinity above levels existing without the project?				
Rule 11-18	☐	☐	☑	☐
Rule 12-16	☐	☐	☑	☐
e) For a project located within an airport land use plan or, where such a plan has not been adopted, within two miles of a public airport or public use airport would the project expose people residing or working in the project area to excessive noise levels?				
Rule 11-18	☐	☐	☐	☑
Rule 12-16	☐	☐	☐	☑
f) For a project within the vicinity of a private airstrip would the project expose people residing or working in the project area to excessive noise levels?				
Rule 11-18	☐	☐	☐	☑
Rule 12-16	☐	☐	☐	☑

Setting

The BAAQMD covers all of Alameda, Contra Costa, Marin, San Francisco, San Mateo, Santa Clara, and Napa Counties and portions of southwestern Solano and southern Sonoma Counties. The area of coverage is vast (about 5,600 square miles) so that land uses and the affected environment vary greatly throughout the area. The facilities affected by the rules are located in commercial and industrial areas of the Bay Area.

Regulatory Background

Noise issues related to construction and operation activities are addressed in local General Plan policies and local noise ordinance standards. The General Plans and noise ordinances generally establish allowable noise limits within different land uses including residential areas, other sensitive use areas (e.g., schools, churches, hospitals, and libraries), commercial areas, and industrial areas.

Discussion of Impacts

XII. a, b, c, and d).

Rule 11-18: Rule 11-18 is designed to reduce risk from existing stationary sources located throughout the Bay Area. Potential risk reduction measures include measures that would limit emissions of TACs. New modifications are expected to be limited to the commercial and industrial facilities. The existing noise environment at each of the affected facilities is typically dominated by noise from existing equipment onsite, vehicular traffic around the facilities, and trucks entering and exiting facility premises. No new major industrial equipment is expected to be required to be installed due to the rule so that no noise impacts associated with the operation of the rule are expected. Air pollution control equipment is not generally a major noise source. Further, all noise producing equipment must comply with local noise ordnances and applicable OSHA and Cal/OSHA noise requirements. Therefore, industrial operations affected by the rule are not expected to have a result in noise exposure that would exceed levels established by local noise control laws or ordinances.

Construction activities associated with the rule may generate some noise associated with temporary construction equipment and construction-related traffic. Construction would likely require truck trips to deliver equipment, a construction crew of up to about 15 workers, and a few pieces of construction equipment (e.g., forklift, welders, backhoes, cranes, and generators). All construction activities would be temporary and are expected to occur within the confines of existing commercial or industrial facilities so that no significant increase in noise is expected.

Rule 11-18 is not expected to generate or expose people to excessive groundborne vibration or groundborne noise. No major construction equipment that would generate vibration (e.g., backhoes, graders, jackhammers, etc.) is expected to be required. Therefore, the rule is not expected to generate excessive groundborne vibration or noise.

Rule 12-16: The petroleum refineries affected by Rule 12-16 already exist and operate within the confines of existing industrial facilities in the Bay Area. Any substantial construction activities associated with new refinery equipment would occur within the confines of existing refineries, located within industrial areas. However, those construction activities would be required to comply with local noise ordinances, which generally prohibit construction during the nighttime, in order to minimize noise impacts. Compliance with the local noise ordinances is expected to minimize noise impacts associated with construction activities to less than significant.

Ambient noise levels in industrial areas are typically driven primarily by freeway and/or highway traffic in the area and any heavy-duty equipment used for materials manufacturing or processing. It is not expected that any modifications to install air pollution control equipment would substantially increase ambient (operational) noise levels in the area, either permanently or intermittently, or expose people to excessive noise levels that would be noticeable above and beyond existing ambient levels. It is not expected that affected facilities would exceed noise standards established in local general plans, noise elements, or noise ordinances currently in effect. Affected refineries would be required to comply with local noise ordinances and elements, which may require construction of noise barriers or other noise control devices.

It is also not anticipated that the rule will cause an increase in groundborne vibration levels because air pollution control equipment is not typically vibration intensive equipment. Consequently, Rule 12-16 is not expected to directly or indirectly cause substantial noise or excessive ground borne vibration impacts. These impacts, therefore, will not be further evaluated in the Draft EIR.

XII. e and f).

Rule 11-18: It is not known if the existing commercial or industrial facilities affected by the rule are located within existing airport land use plans. The addition of new or modification of existing air pollution control equipment or enclosures would not expose people residing or working in the project area to excessive noise levels associated with airports, as air pollution control equipment are not typically noise generating equipment. Rule 11-18 would not locate residents or commercial buildings or other sensitive noise sources closer to airport operations. As noted in the previous item, there are no components of the rule that would substantially increase ambient noise levels, either intermittently or permanently.

Rule 12-16: If applicable, the petroleum refineries affected by Rule 12-16 would still be expected to comply, and not interfere, with any applicable airport land use plans. The existing refineries are not located within existing airport land use plans. Rule 12-16 would not locate residents or commercial buildings or other sensitive noise sources closer to airport operations. As noted in the previous item, there are no components of the rule that would substantially increase ambient noise levels, either intermittently or permanently.

Conclusions

Based upon the above considerations, no significant adverse project-specific noise impacts are expected due to implementation of either Rule 11-18 or Rule 12-16; therefore, noise impacts will not be further evaluated in the Draft EIR.

XIII. POPULATION AND HOUSING.

Would the project:	Potentially Significant Impact	Less Than Significant Impact with Mitigation Incorporated	Less-than-Significant Impact	No Impact
a) Induce substantial population growth in an area either directly (e.g., by proposing new homes and businesses) or indirectly (e.g. through extension of roads or other infrastructure)?				
Rule 11-18	☐	☐	☐	☑
Rule 12-16	☐	☐	☐	☑
b) Displace a substantial number of existing housing units, necessitating the construction of replacement housing elsewhere?				
Rule 11-18	☐	☐	☐	☑
Rule 12-16	☐	☐	☐	☑
c) Displace a substantial number of people, necessitating the construction of replacement housing elsewhere?				
Rule 11-18	☐	☐	☐	☑
Rule 12-16	☐	☐	☐	☑

Setting

The BAAQMD covers all of Alameda, Contra Costa, Marin, San Francisco, San Mateo, Santa Clara, and Napa Counties and portions of southwestern Solano and southern Sonoma Counties. The area of coverage is vast (about 5,600 square miles) so that land uses and the affected environment vary greatly throughout the area. The facilities affected by the Rules 11-18 and 12-16 are generally industrial and commercial facilities within the jurisdiction of the BAAQMD.

Regulatory Background

Population and housing growth and resources are generally protected and regulated by the City and/or County General Plans through land use and zoning requirements.

Discussion of Impacts

XIII. a). According to the Association of Bay Area Governments (ABAG), population in the Bay Area is currently about seven million people and is expected to grow to about nine million people by 2035 (ABAG, 2006).

<u>Rule 11-18</u>: Rule 11-18 is not anticipated to generate any significant effects, either directly or indirectly, on the Bay Area's population or population distribution. The rule would affect commercial and industrial facilities. It is expected that the existing labor pool would accommodate the labor

requirements for any new or modified equipment at the facilities. In addition, it is not expected that the affected facilities would need to hire additional personnel to implement the rule. In the event that new employees are hired, it is expected that the existing local labor pool in the Bay Area can accommodate any increase in demand for workers that might occur as a result of adopting the rule. As such, adopting propose Rule 11-18 is not expected to induce substantial population growth.

Rule 12-16: Rule 12-16 is not anticipated to generate any significant effects, either directly or indirectly, on the Bay Area's population or population distribution. The rule would affect five refineries and three associated facilities located in Contra Costa and Solano counties. It is expected that the existing labor pool would accommodate the labor requirements for any modifications at the affect refineries. In addition, it is not expected that the affected refineries would need to hire additional personnel to operate and maintain new control equipment on site because air pollution control equipment is typically not labor intensive equipment. In the event that new employees are hired, it is expected that the existing local labor pool in the Bay Area can accommodate any increase in demand for workers that might occur as a result of adopting the rule. As such, adopting Rule 12-16 is not expected to induce substantial population growth.

XIII. b and c). Rules 11-18 and 12-16: Both of the rules could result in the installation of air pollution control equipment operated in commercial and industrial settings. However, Rules 11-18 and 12-16 are not expected to result in the creation of any industry that would affect population growth, directly or indirectly induce the construction of single- or multiple-family units, or require the displacement of people or housing elsewhere in the Bay Area. Based upon these considerations, significant population and housing impacts are not expected from the implementation of the rules.

Conclusions

Based upon the above considerations, significant adverse project-specific impacts to population and housing are not expected to occur due to implementation of either Rule 11-18 or Rule 12-16 and, therefore, will not be further evaluated in the Draft EIR.

XIV. PUBLIC SERVICES.

Would the project:	Potentially Significant Impact	Less Than Significant Impact with Mitigation Incorporated	Less-than-Significant Impact	No Impact
a) Result in substantial adverse physical impacts associated with the provision of new or physically altered governmental facilities or a need for new or physically altered governmental facilities, the construction of which could cause significant environmental impacts, in order to maintain acceptable service ratios, response times, or other performance objectives for any of the following public services:				
Fire protection?				
Rule 11-18	☐	☐	☐	☑
Rule 12-16	☐	☐	☐	☑
Police protection?				
Rule 11-18	☐	☐	☐	☑
Rule 12-16	☐	☐	☐	☑
Schools?				
Rule 11-18	☐	☐	☐	☑
Rule 12-16	☐	☐	☐	☑
Parks?				
Rule 11-18	☐	☐	☐	☑
Rule 12-16	☐	☐	☐	☑
Other public facilities?				
Rule 11-18	☐	☐	☐	☑
Rule 12-16	☐	☐	☐	☑

Setting

The BAAQMD covers all of Alameda, Contra Costa, Marin, San Francisco, San Mateo, Santa Clara, and Napa Counties and portions of southwestern Solano and southern Sonoma Counties. The area of coverage is vast (about 5,600 square miles) so that land uses and the affected environment vary greatly throughout the area. The facilities affected by the rules are primarily located in commercial and industrial areas within the Bay Area.

Given the large area covered by the BAAQMD, public services are provided by a wide variety of local agencies. Fire protection and police protection/law enforcement services within the BAAQMD are provided by various districts, organizations, and agencies. There are several school districts, private schools, and park departments within the BAAQMD. Public facilities within the BAAQMD are managed by different county, city, and special-use districts. All refineries affected by the rules maintain fire-fighting equipment and trained personnel with fire-fighting and emergency response experience. In addition, all affected refineries operated on-site security systems.

Regulatory Background

City and/or County General Plans usually contain goals and policies to assure adequate public services are maintained within the local jurisdiction.

Discussion of Impacts

XIV. a).

Rule 11-18: The rule is designed to reduce toxic health risks from stationary sources in the Bay Area. Rule 11-18 could require minor construction activities and modifications at existing facilities. The modifications are not expected to require additional service from local fire or police departments above current levels.

As noted in the “Population and Housing” discussion above, the rule is not expected to induce population growth because the local labor pool (e.g., workforce) is expected to be sufficient to accommodate any activities that may be necessary at affected facilities. Additionally, modifications to existing facilities are not expected to require an increase in employees. Therefore, there will be no increase in local population and thus no impacts are expected to local schools or parks.

The rule would not result in the need for new or physically altered government facilities in order to maintain acceptable service ratios, response times, or other performance objectives. There will be no increase in population as a result of the adoption of the rule, therefore, no need for physically altered government facilities.

Rule 12-16: Rule 12-16 would limit the emissions of certain air pollutant and could require the installation of additional air pollution control equipment or modify refinery operations if those thresholds are exceeded. As stated above, all refineries affected by the rule, maintain on-site fire-fighting equipment and trained personnel with fire-fighting and emergency response experience. While Rule 12-16 could require new construction activities and the operation of new/modified refinery equipment, the additional equipment is not expected to require additional service from local fire departments above current levels.

Refineries maintain their own security systems. Refineries are fenced and access is controlled at manned gates. Modification associated with the rule would occur within the confines of the existing refineries. Therefore, the rule is not expected to increase the need or demand for additional police services above current levels.

As noted in the “Population and Housing” discussion above, the rule is not expected to induce population growth because the local labor pool (e.g., workforce) is expected to be sufficient to accommodate any activities that may be necessary at affected facilities. Additionally, operation of new air monitoring and air pollution control equipment is not expected to require a substantial increase in employees. Therefore, there will be no increase in local population and thus no impacts are expected to local schools or parks.

Conclusions

Based upon the above considerations, significant adverse project-specific impacts to public services are not expected to occur due to implementation of either Rule 11-18 or Rule 12-16 and, therefore, will not be further evaluated in the Draft EIR.

XV. RECREATION.

Would the project:	Potentially Significant Impact	Less Than Significant Impact with Mitigation Incorporated	Less-than-Significant Impact	No Impact
a) Would the project increase the use of existing neighborhood and regional parks or other recreational facilities such that substantial physical deterioration of the facility would occur or be accelerated?				
Rule 11-18	☐	☐	☐	☑
Rule 12-16	☐	☐	☐	☑
b) Does the project include recreational facilities or require the construction or expansion of recreational facilities that might have an adverse physical effect on the environment?				
Rule 11-18	☐	☐	☐	☑
Rule 12-16	☐	☐	☐	☑

Setting

The BAAQMD covers all of Alameda, Contra Costa, Marin, San Francisco, San Mateo, Santa Clara, and Napa Counties and portions of southwestern Solano and southern Sonoma Counties. The area of coverage is vast (about 5,600 square miles) so that there are numerous areas for recreational activities. The refineries affected by the Rules 11-18 and 12-16 are located in industrial areas within the Bay Area. Public recreational land can be located adjacent to, or in reasonable proximity to, these areas.

As noted in the “Population and Housing” discussion above, the rules are not expected to induce population growth because the local labor pool (e.g., workforce) is expected to be sufficient to accommodate any activities that may be necessary at affected facilities. Additionally, operation of new air pollution control equipment is not expected to require additional employees. Therefore, there will be no increase in local population and thus no impacts are expected to local schools or parks.

Regulatory Background

Recreational areas are generally protected and regulated by the City and/or County General Plans at the local level through land use and zoning requirements. Some parks and recreation areas are designated and protected by state and federal regulations.

Discussion of Impacts

XV. a and b). Rules 11-18 and 12-16: As discussed under "Land Use" above, there are no provisions of the rules that would affect land use plans, policies, or regulations. Land use and other planning considerations are determined by local governments; no land use or planning requirements will be altered by either Rule 11-18 or Rule 12-16. Air pollution control equipment, if necessary, would be installed within the confines of existing facilities, including refineries, and would not impact existing recreational facilities.

As noted in the "Population and Housing" discussion above, the rules are not expected to induce population growth because the local labor pool (e.g., workforce) is expected to be sufficient to accommodate any activities that may be necessary at affected facilities. Additionally, operation of new air pollution control equipment is not expected to require a substantial increase in employees. Therefore, there will be no increase in local population and thus no impacts are expected to local recreational facilities.

Conclusions

Based upon the above considerations, significant adverse project-specific impacts to recreation are not expected to occur due to implementation of either Rule 11-18 or Rule 12-16 and, therefore, will not be further evaluated in the Draft EIR.

XVI. TRANSPORTATION / TRAFFIC.

Would the project:	Potentially Significant Impact	Less Than Significant Impact with Mitigation Incorporated	Less-than-Significant Impact	No Impact
a) Conflict with an applicable plan, ordinance or policy establishing measures of effectiveness for the performance of the circulation system, taking into account all modes of transportation including mass transit and non-motorized travel and relevant components of the circulation system, including but not limited to intersections, streets, highways and freeways, pedestrian and bicycle paths, and mass transit?				
Rule 11-18	☐	☐	☑	☐
Rule 12-16	☐	☐	☐	☑
b) Conflict with an applicable congestion management program, including, but not limited to level of service standards and travel demand measures, or other standards established by the county congestion management agency for designated roads or highways?				
Rule 11-18	☐	☐	☑	☐
Rule 12-16	☐	☐	☐	☑
c) Result in a change in air traffic patterns, including either an increase in traffic levels or a change in location that results in substantial safety risks?				
Rule 11-18	☐	☐	☐	☑
Rule 12-16	☐	☐	☐	☑
d) Substantially increase hazards because of a design feature (e.g. sharp curves or dangerous intersections) or incompatible uses (e.g. farm equipment)?				
Rule 11-18	☐	☐	☐	☑
Rule 12-16	☐	☐	☐	☑
e) Result in inadequate emergency access?				
Rule 11-18	☐	☐	☐	☑
Rule 12-16	☐	☐	☐	☑
f) Conflict with adopted policies, plans or programs regarding public transit, bicycle, or pedestrian facilities, or otherwise decrease the performance or safety of such facilities?				
Rule 11-18	☐	☐	☐	☑
Rule 12-16	☐	☐	☐	☑

Setting

The BAAQMD covers all of Alameda, Contra Costa, Marin, San Francisco, San Mateo, Santa Clara, and Napa Counties and portions of southwestern Solano and southern Sonoma Counties. The area of coverage is vast (about 5,600 square miles). Transportation systems located within the Bay Area include railroads, airports, waterways, and highways. The Port of Oakland and three international airports in the area serve as hubs for commerce and transportation. The transportation infrastructure for vehicles and trucks in the Bay Area ranges from single lane roadways to multilane interstate highways. The Bay Area currently contains over 1,300 directional miles of limited-access highways, which include both interstates and state highways. In addition, the Bay Area has over 33,000 directional miles of arterials and local streets, providing more localized access to individual communities. Together, these roadway facilities accommodate nearly 17 million vehicle trips a day. There are over 11,500 transit route miles of service including heavy rail (BART), light rail (Muni Metro and VTA Light Rail), commuter rail (Caltrain and ACE), diesel and electric buses, cable cars, and ferries. The Bay Area also has an extensive local system of bicycle routes and pedestrian paths and sidewalks. At a regional level, the share of workers driving alone was about 68 percent in 2010. The portion of commuters that carpool was about 11 percent in 2010, while an additional 10 percent utilize public transit. About 3 percent of commuters walked to work in 2010. In addition, other modes of travel (bicycle, motorcycle, etc.), account for three percent of commuters in 2010 (MTC, 2013). Cars, buses, and commercial vehicles travel about 149 million miles a day (2010) on the Bay Area Freeways and local roads. Transit serves about 1.6 million riders on the average weekday (MTC, 2013).

The region is served by numerous interstate and U.S. freeways. On the west side of San Francisco Bay, Interstate 280 and U.S. 101 run north-south. U.S. 101 continues north of San Francisco into Marin County. Interstates 880 and 660 run north-south on the east side of the Bay. Interstate 80 starts in San Francisco, crosses the Bay Bridge, and runs northeast toward Sacramento. Interstate 80 is a six-lane north-south freeway which connects Contra Costa County to Solano County via the Carquinez Bridge. State Routes 29 and 84, both highways that allow at-grade crossings in certain parts of the region, become freeways that run east-west and cross the Bay. Interstate 580 starts in San Rafael, crosses the Richmond-San Rafael Bridge, joins with Interstate 80, runs through Oakland, and then runs eastward toward Livermore. From the Benicia-Martinez Bridge, Interstate 680 extends north to Interstate 80 in Cordelia. Interstate 780 is a four lane, east-west freeway extending from the Benicia-Martinez Bridge west to I-80 in Vallejo.

Regulatory Background

Transportation planning is usually conducted at the state and county level. Planning for interstate highways is generally done by Caltrans.

Most local counties maintain a transportation agency that has the duties of transportation planning and administration of improvement projects within the county and implements the Transportation Improvement and Growth Management Program, and the congestion management plans (CMPs). The CMP identifies a system of state highways and regionally significant principal arterials and specifies level of service standards for those roadways.

Discussion of Impacts

XVI. a and b).

Rule 11-18: Construction: The rule is designed to reduce health risks from stationary sources in the Bay Area. Any new or modified pollution control equipment is expected to be located in commercial, industrial, or institutional facilities and may require construction activities. Construction impacts were considered for the control measures found in Table 2-1. Control measures that do not require equipment, such as reducing operating time, are not expected to generate any additional traffic. The BAAQMD estimates that approximately 30 facilities per year are expected to meet reductions by implementing either a baghouse or an enclosure. The construction of enclosures is expected to require the most construction equipment and workers. This could require up to 34 delivery and/or disposal trucks and up to about 45 construction worker trips on a peak construction day (during the building construction phase for enclosures). Given the size of the Bay Area, this amount of construction traffic would not be noticeable, particularly since construction activities would be expected at existing commercial, industrial and institutional land uses and would be temporary. The rule is not expected to require modification to circulation for temporary construction activities. As a result, construction traffic from Rule 11-18 would not have significant impacts on the performance of the circulation system or on standards established for congestion management.

Operational: Waste products may be generated from the use of several types of control technologies. Wastes could include: spent carbon generated from the carbon adsorption process; spent metal catalysts from the catalytic oxidation process; and dry solids from filtration controls. The majority of wastes will likely need to be transported to disposal or recycling facilities. The catalysts in catalytic oxidizers need to be replaced every few years so this potential waste product was considered to contribute to the waste transport impacts.

For a “worst case” analysis, it was assumed that about 180 facilities per year would be required to install a control device to comply with the rule. These facilities at any given day would generate an additional one-two truck trips per day in the entire Air District for delivery and disposal. These potential truck trips are not expected to significantly adversely affect circulation patterns on local roadways near affected facilities. In addition, this volume of additional daily truck traffic is negligible over the entire area of the Air District. Finally, the number of waste disposal transport trips substantially overestimates the number of anticipated trips because owners/operators at affected facilities may use other types of add-on control equipment and most are expected to limit throughput rates or operating times which would have no impact on traffic. No increase in worker traffic is expected as the operation of air pollution control equipment of the type expected under the rule is not expected to require any additional employees. Therefore, operational traffic under the Rule 11-18 is expected to be less than significant.

Rule 12-16: The petroleum refineries affected by the rule already exist and operate within the confines of existing industrial facilities in the Bay Area. Construction activities could be required to install air pollution control equipment associated with compliance with the emissions limits contained in the rule. Any substantial construction activities associated with new refinery equipment would occur within the confines of existing refineries. Construction activities are temporary and the related construction worker traffic and delivery trucks would cease following completion of construction. No substantial increase in workers or average daily vehicle or truck trips is anticipated as a result of Rule 12-16. Therefore, the rule is not expected to result in traffic that would exceed, either individually or cumulatively, the current level of service at intersections in the vicinity of the refineries. The work force at each affected facility is not expected to substantially change as a result of the rule and any permanent increase in operation-related traffic is expected to be minimal. Thus, the traffic impacts associated with Rule 12-16 are expected to be less than significant.

XVI. c).

Rule 11-18: The rule is not expected to involve the delivery of materials via air, so no increase in air traffic is expected. The addition of new or modified air pollution control equipment is not expected to change air traffic patterns or result in a change in location that results in substantial safety risks.

Rule 12-16: Rule 12-16 would not result in a change in air traffic patterns or increase air traffic. Actions that would be taken to comply with the rule, such as installing new air pollution control equipment, would not influence or affect air traffic patterns. Further, air pollution control equipment is expected to be lower in height than other existing structures at the refinery and would not impact navigable air space. Thus, Proposed Rule 12-16 would not result in a change in air traffic patterns including an increase in traffic levels or a change in location that results in substantial safety risks.

XVI. d and e).

Rule 11-18: Rule 11-18 is not expected to increase traffic hazards or create incompatible uses. The rule does not involve construction of any roadways or other transportation design features, so no changes to current roadway designs that would increase traffic hazards are expected. Emergency access at the commercial and industrial facilities affect by the Proposed Rule 11-18 is not expected to be impacted by the rule. Each affected facility is expected to continue to maintain their existing emergency access. The rule is not expected to increase vehicle trips or to alter the existing long-term circulation patterns. The rule is not expected to require a modification to circulation, thus, no long-term impacts on the traffic circulation system are expected to occur.

Rule 12-16: Rule 12-16 would not alter traffic patterns or existing roadways, as it is not expected to generate any substantial increase in traffic. The rule would not create any traffic hazards or create incompatible uses at or adjacent to refineries. Any construction activities associated with the rule would be temporary and located within the confines of the existing refineries. The rule is not expected to require circulation modifications, thus, no long-term impacts on the traffic circulation system are expected to occur. The rule does not involve construction of any roadways, so there would be no increase in any roadway design feature that could increase traffic hazards. Emergency access at each refinery would not be impacted by implementation of Rule 12-16. Further, each affected refinery would continue to maintain their existing emergency access gates and installation of new refinery equipment is not expected to impact emergency access.

XVI. f).

Rule 11-18: The rule is not expected to affect the performance of mass transit or non-motorized travel to street, highways and freeways, pedestrian or bicycle paths. No conflicts with any congestion management programs, to include level of service and travel demand measures, or other standards established by county congestion management agencies for designated roads or highways, are expected. No changes are expected to parking capacity at or in the vicinity of affected facilities as the rule only pertains to equipment located within existing commercial and industrial facilities. Therefore, no significant adverse impacts resulting in changes to traffic patterns or levels of service at local intersections are expected.

Rule 12-16: Activities resulting from Rule 12-16 would not conflict with policies supporting alternative transportation since the rule does not involve or affect alternative transportation modes (e.g. bicycles or buses). Any construction activities associated with Proposed Rule 12-16 would be conducted at existing refineries and would be temporary so once completed, transportation, including alternative transportation modes, would not be effected.

Conclusions

Based upon the above considerations, significant adverse project-specific impacts to transportation/traffic are not expected to occur due to implementation of either Rule 11-18 or Rule 12-16 and, therefore, will not be further evaluated in the Draft EIR.

XVII. UTILITIES / SERVICE SYSTEMS.

Would the project:	Potentially Significant Impact	Less Than Significant Impact with Mitigation Incorporated	Less-than-Significant Impact	No Impact
a) Exceed wastewater treatment requirements of the applicable Regional Water Quality Control Board?				
Rule 11-18	☐	☐	☑	☐
Rule 12-16	☑	☐	☐	☐
b) Require or result in the construction of new water or wastewater treatment facilities or expansion of existing facilities, the construction of which could cause significant environmental effects?				
Rule 11-18	☐	☐	☑	☐
Rule 12-16	☑	☐	☐	☐
c) Require or result in the construction of new storm water drainage facilities or expansion of existing facilities, the construction of which could cause significant environmental effects?				
Rule 11-18	☐	☐	☐	☑
Rule 12-16	☐	☐	☐	☑
d) Have sufficient water supplies available to serve the project from existing entitlements and resources, or would new or expanded entitlements needed?				
Rule 11-18	☐	☐	☑	☐
Rule 12-16	☑	☐	☐	☐
e) Result in a determination by the wastewater treatment provider which serves or may serve the project that it has adequate capacity to serve the project's projected demand in addition to the provider's existing commitments?				
Rule 11-18	☐	☐	☑	☐
Rule 12-16	☑	☐	☐	☐
f) Be served by a landfill with sufficient permitted capacity to accommodate the project's solid waste disposal needs?				
Rule 11-18	☐	☐	☑	☐
Rule 12-16	☐	☐	☑	☐
g) Comply with federal, state, and local statutes and regulations related to solid waste?				
Rule 11-18	☐	☐	☑	☐
Rule 12-16	☐	☐	☑	☐

Setting

The BAAQMD covers all of Alameda, Contra Costa, Marin, San Francisco, San Mateo, Santa Clara, and Napa Counties and portions of southwestern Solano and southern Sonoma Counties. The area of coverage is vast (about 5,600 square miles), so that land uses and the affected environment vary greatly throughout the area.

Given the large area covered by the BAAQMD, public utilities are provided by a wide variety of local agencies. The affected facilities have wastewater and storm water treatment facilities and discharge treated wastewater under the requirements of NPDES permits.

Water is supplied to affected facilities by several water purveyors in the Bay Area. Solid waste is handled through a variety of municipalities, through recycling activities, and at disposal sites.

There are no hazardous waste disposal sites within the jurisdiction of the BAAQMD. Hazardous waste generated at area facilities, which is not reused on-site or recycled off-site, is disposed of at a licensed in-state hazardous waste disposal facility. Two hazardous waste disposal facilities are located in California: (1) The Clean Harbors facility in Buttonwillow (Kern County); and (2) the Waste Management facility in Kettleman Hills. Hazardous waste also can be transported to permitted facilities outside of California. The nearest out-of-state landfills are U.S. Ecology, Inc., located in Beatty, Nevada and USPCI, Inc., in Murray, Utah.

Regulatory Background

City and/or County General Plans usually contain goals and policies to assure adequate utilities and service systems are maintained within the local jurisdiction.

Discussion of Impacts

XVII. a, b, d and e).

Rule 11-18: Rule 11-18 is designed to reduce health risks from stationary sources in the Bay Area. The facilities affected by the rule already exist and already use water, generate wastewater, treat wastewater, and discharges wastewater under existing wastewater discharge permits. The potential water use and wastewater impacts associated with implementation of Rule 11-18 are addressed under Hydrology and Water Quality (see Section IX a.) and have been determined to be less than significant.

Rule 12-16: The refineries affected by Rule 12-16 already exist and already use water, generate wastewater, treat wastewater, and discharge wastewater under existing wastewater discharge permits. The rule may potentially require additional air pollution control equipment. The potential water use and wastewater impacts associated with implementation of Rule 12-16 are addressed under Hydrology and Water Quality (see Section IX a.).

XVII. c).

Rule 11-18: Implementation of Rule 11-18 may require new or modified pollution control equipment within the confines of existing facilities. These modifications would not alter the existing drainage system or require the construction of new storm water drainage facilities. Nor would the changes required by the rule create or contribute runoff water that would exceed the capacity of existing or planned storm water drainage systems or provide substantial additional sources of polluted runoff. Therefore, no significant adverse impacts on storm drainage facilities are expected.

Rule 12-16: Rule 12-16 may result in the installation of air pollution control equipment, but would not alter the existing drainage system or require the construction of new storm water drainage facilities. Nor would the rule create or contribute runoff water that would exceed the capacity of existing or planned storm water drainage systems or provide substantial additional sources of polluted runoff. Therefore, no significant adverse impacts on storm drainage facilities are expected.

XVII. f and g).

Rule 11-18: The rule would reduce health risk posed by existing commercial or industrial facilities. The primary method for reducing these health impacts would be to reduce emissions of TACs, including the use of control technology like baghouses and catalytic oxidizers. Baghouses and catalytic oxidizers will generate solid waste, but they are not expected to require annual replacement events. The baghouses and spent catalyst are only expected to generate a few tons of waste per change out. It is assumed that any hazardous material will be taken to the U.S. Ecology Beatty Nevada hazardous waste facility for treatment and disposal. U.S. Ecology, Inc. is currently receiving waste, and is in the process of extending the operational capacity for an additional 35 years (U.S. Ecology, 2015). Clean Harbors in Grassy Mountain, Utah is also available to receive hazardous waste and is expected to continue to receive waste for an additional 70 years (Clean Harbors, 2015). Therefore, the rule impacts on hazardous waste landfills are less than significant.

The rule is not expected to generate any significant increase in solid waste. Therefore, no significant adverse impacts are expected to solid waste as a result of the rule.

Rule 12-16: No significant impacts on waste generation are expected from the implementation of Proposed Rule 12-16 because the rule would potentially result in the installation of additional air pollution control equipment which is not expected to create substantial quantities of solid or hazardous waste. Waste streams from refineries would be processed similarly as current methods, so no significant impact to land disposal facilities would be expected. Therefore, no significant impacts to hazardous waste disposal facilities are expected due to the rule. Facilities are expected to continue to comply with all applicable federal, state, and local statutes and regulations related to solid and hazardous wastes.

Conclusions

Rule 11-18: Based upon these considerations, no significant adverse impacts to utilities/service systems are expected from the adoption of the rule.

Rule 12-16: The potential water and wastewater impacts associated with implementation of Rule 12-16 are addressed under Hydrology and Water Quality (see Section IX above). Based upon the above considerations, no additional significant adverse impacts are expected to storm water drainage, solid waste disposal or landfills due to implementation of Rule 12-16. Therefore, the impacts on utilities will not be further evaluated in the Draft EIR (except for the water and wastewater impacts that will be addressed under Hydrology and Water Quality).

XVIII. MANDATORY FINDINGS OF SIGNIFICANCE.

Would the project:	Potentially Significant Impact	Less Than Significant Impact with Mitigation Incorporated	Less-than-Significant Impact	No Impact
a) Does the project have the potential to degrade the quality of the environment, substantially reduce the habitat of a fish or wildlife species, cause a fish or wildlife population to drop below self-sustaining levels, threaten to eliminate a plant or animal community, reduce the number or restrict the range of a rare or endangered plant or animal, or eliminate important examples of the major periods of California history or prehistory?				
Rule 11-18	☐	☐	☐	☑
Rule 12-16	☐	☐	☐	☑
b) Does the project have impacts that are individually limited, but cumulatively considerable? ("Cumulatively considerable" means that the incremental effects of a project are considerable when viewed in connection with the effects of past projects, the effects of other current projects, and the effects of probable future projects)?				
Rule 11-18	☑	☐	☐	☐
Rule 12-16	☑	☐	☐	☐
c) Does the project have environmental effects that will cause substantial adverse effects on human beings, either directly or indirectly?				
Rule 11-18	☐	☐	☑	☐
Rule 12-16	☐	☐	☑	☐

Discussion of Impacts

XVIII. a).

Rule 11-18: Rule 11-18 does not have the potential to degrade the quality of the environment, substantially reduce the habitat of a fish or wildlife species, cause a fish or wildlife population to drop below self-sustaining levels, threaten to eliminate a plant or animal community, reduce the number or restrict the range of a rare or endangered plant or animal, or eliminate important examples of the major periods of California history or prehistory, as discussed in the previous sections of the CEQA checklist. The rule is designed to reduce health risks from commercial or industrial facilities in the Bay Area, thus providing a beneficial air quality impact and improvement in air quality. As discussed in Section IV, Biological Resources and Section V, Cultural Resources, no significant adverse impacts are expected to biological or cultural resources.

Rule 12-16: Rule 12-16 does not have the potential to degrade the quality of the environment, substantially reduce the habitat of a fish or wildlife species, cause a fish or wildlife population to drop below self-sustaining levels, threaten to eliminate a plant or animal community, reduce the number or restrict the range of a rare or endangered plant or animal, or eliminate important examples of the major periods of California history or prehistory, as discussed in the previous sections of the CEQA checklist. Rule 12-16 may require the installation of emission control equipment. As discussed in Section IV, Biological Resources and Section V, Cultural Resources, no significant adverse impacts are expected to biological or cultural resources, as any construction activities are expected to remain within the confines of existing refineries which have already been graded and developed.

XVIII. b and c).

Rule 11-18: The rule is designed to reduce health risks from commercial, industrial and institutional facilities in the Bay Area, thus providing a beneficial air quality impact and improvement in air quality. However, construction and operation of air pollution control equipment has the potential to increase emissions of other emissions, including GHGs and criteria pollutants. The potential secondary adverse air quality impacts associated with implementing Rule 11-18, including any cumulative air quality impacts will be evaluated in the EIR. The rule is expected to reduce TAC emissions, thus reducing the potential health impacts.

Rule 12-16: Rule 12-16 may require the installation of emission control equipment, if the emissions limits are exceeded. The rule could require construction and installation of new air pollution control equipment which could result in secondary air emissions as well as additional GHG emissions. Therefore, the air quality and cumulative impacts associated with implementation of Rule 12-16 will be evaluated in the Draft EIR.

Chapter 3

References

Association of Bay Area Governments, 2006. Projections 2007, December 2006.

BAAQMD, 2010. Bay Area 2010 Clean Air Action Plan, September 15, 2010.

Metropolitan Transportation Commission (MTC), 2013. Environmental Impact Report Plan Bay Area Draft. Metropolitan Transportation Commission and Bay Area Association of Governments. April, 2013.

APPENDIX A

BAAQMD REGULATION 11, RULE 18: REDUCTION OF RICK FROM AIR TOXIC EMISSIONS
&
BAAQMD REGULATION 12, RULE 16: PETROLEUM REFINIG FACILITY-WIDE EMISSIONS LIMITS

COMMENTS LETTER RECEIVED ON THE NOP/IS

COMMENTS:

The following comments were received on the NOP/IS for the BAAQMD Regulation 11, Rule 18: Reduction of Risk from Air Toxic Emissions and BAAQMD Regulation 12, Rule 16: Petroleum Refining Facility-Wide Emissions Limits Project. The names of the commenters are provided in Table A-1.

TABLE A-1
List of Commenters

CASA	Greg Kester, California Association of Sanitation Agencies
CAP	Cathy Helgerson, Citizens Against Pollution
CBE	CBE Technical Report, Combustion Emissions from Refining Lower Quality Oil
CBE et al.	Devorah Ancel, Sierra Club; Kevin Bundy, Center for Biological Diversity; Laurence G. Chaset, Sustainable Energy Futures for 350 Bay Area; Roger Lin, Communities for a Better Environment; David Pettit, Natural Resource Defense Council
CBE et al. 2	Devorah Ancel, Staff Attorney, Sierra Club Kevin Bundy, Senior Attorney and Climate Legal Director, Center for Biological Diversity Laurence G. Chaset, Attorney at Law, Sustainable Energy Futures on behalf of 350 Bay Area Roger Lin, Staff Attorney, Communities for a Better Environment David Pettit, Senior Attorney, Natural Resources Defense Council Comment also supported by: Janice L. Kirsch, M.D., M.P.H., San Francisco Bay Area Chapter, The Climate Mobilization Steve Nadel and Charles Davidson, Sunflower Alliance Nancy Rieser, Crockett-Rodeo United to Defend the Environment David McCoard, SF Bay Chapter, Sierra Club Energy-Climate Committee Katherine Black, Benicians for a Safe and Healthy Community

	Bradley Angel, Greenaction for Health and Environmental Justice Richard Gray, 350 Bay Area Denny Larson, Community Science Institute Ratha Lai, Asian Pacific Environmental Network Janet Johnson, Richmond Progressive Alliance Nan Parks, 350 East Bay Jan Warren, Interfaith Climate Action Network of Contra Costa County Luis Amezcua, Sierra Club Bay Chapter
CCEEB	Bill Quinn, California Council for Environmental and Economic Balance
Health Professionals	Bart Ostro PHD, Former Chief of Air Pollution Epidemiology Section, California EPA, currently Research Faculty, Air Quality Research Center, UC Davis Amy D Kyle PhD, MPH, School of Public Health, University of California Berkeley (Institution for identification only) Claire V Broome, MD Adjunct Professor, Rollins School of Public Health Emory University Assistant Surgeon General, US Public Health Service (retired) Linda Rudolph MD MPH, Director, Center for Climate Change and Health Oakland CA Jonathan Heller PhD, Co-Director and Co-Founder, Human Impact Partners Oakland CA Wendel Brunner MD, PhD, MPH, Former Director of Public Health, Contra Costa Health Services Kathy Dervin MPH, Senior Climate and Health Consultant, Berkeley CA Janice L Kirsch MD MPH, Medical oncologist and hematologist Heather Kuiper DrPH MPH, Public Health Consultant, Oakland CA
Phillips 66	Don Bristol, Phillips 66
WSPA	Catherine Reheis-Boyd, Western States Petroleum Association

CALIFORNIA ASSOCIATION of SANITATION AGENCIES

1225 8th Street, Suite 595• Sacramento, CA 95814 • TEL: (916) 446-0388 • www.casaweb.org

December 2, 2016

SUBMITTAL VIA EMAIL TO: vdouglas@baaqmd.gov

Mr. Victor Douglas
Principal Air Quality Specialist
Technical Services
Bay Area Air Quality Management District
375 Beale Street, Suite 600
San Francisco, CA 94105

SUBJECT: COMMENT LETTER ON PROPOSED BAAQMD REGULATION 11, RULE 18: REDUCTION OF RISK FROM AIR TOXIC EMISSIONS AT EXISTING FACILITIES

Dear Mr. Douglas:

The California Association of Sanitation Agencies (CASA) appreciates the opportunity to comment on the Bay Area Air Quality Management District's (BAAQMD) proposed Regulation 11, Rule 18 (Rule 11-18). CASA is an association of local agencies, engaged in advancing the recycling of wastewater into usable water, generation of renewable energy, biosolids and other valuable resources. Through these efforts we help create a clean and sustainable environment for millions of Californians.

It appears that the proposed Rule 11-18 has been developed in reaction to community concern about only a few existing facilities, and the BAAQMD's proposed regulatory response impacts more agencies than necessary to reach its air quality goals. BAAQMD staff estimate that hundreds of facilities could be affected by this rule (Notice of Preparation/Initial Study; Regulation 11, Rule 18 and Regulation 12, Rule 16; Page 1-9 October 2016). While CASA appreciates the outreach that BAAQMD staff has done, there are dozens of POTWs that have not been engaged on this issue, and have only very recently become somewhat aware of this significant regulatory initiative. Based on this sector, it seems likely that there are far more, perhaps hundreds, of potentially impacted facilities who are not aware nor have considered the impact and cost of this Regulation, and have thus not had the opportunity to provide meaningful comments for your consideration. Therefore, we ask that the BAAQMD consider a more robust effort to meet in workshop formats with all affected facilities to review the basis for the Regulation, describe the proposed compliance routes, and collectively understand its potential impacts. CASA has further concerns that the action taken by the BAAQMD may be mimicked in other Air Districts and thus believes it is critical that any action be fully vetted and supported by science.

CASA's specific comments on the proposed Rule 11-18 are as follows:

1) <u>Public notification by BAAQMD for Rule 11-18 should clarify that emissions have not increased</u>

Despite there being no change in a POTW's emissions levels, incorporating the updated California Air Pollution Control Officers Association (CAPCOA) risk factors and guidelines may result in the first notification the public receives about an existing facility within its vicinity. This notification could result in greater public anxiety about health risks from existing stationary sources. Providing a clear explanation that the changes in facility risk estimates are due exclusively to changes in risk assessment methodology, not actual increases in emissions (and health risk), should be incorporated in the public notification. CASA, along with many other public and private entities raised this issue in a letter to CAPCOA on October 27, 2016. Please let me know if you would like a copy of that letter.

CASA recommends the public notification of risk include language providing context to the risk values to improve public understanding and reduce potential anxiety.

2) <u>Proposed rule should not inadvertently discourage renewable energy production</u>

While the purpose of the proposed Rule 11-18 is to reduce toxic air contaminants and protect public health, it may discourage the production and beneficial use of biogas for the generation of renewable energy or fuel, resulting in a wasted (flared) resource. Most CASA members already beneficially use biogas generated from anaerobic digestion of sewage sludge to generate renewable electricity. Not only does this practice offset the treatment plant's dependence on fossil fuel based energy, it reduces the resulting anthropogenic greenhouse gas emissions.

The production of biogas, production of renewable energy, and the reduction of greenhouse gas emissions support statewide greenhouse gas reduction goals set under Assembly Bill 32 and Senate Bill 32. Furthermore, the State Air Resources Board would like to see POTWs accept additional organic waste streams (specifically, diverted food waste and fats, oils, and grease from landfills) for co-digestion with sewage sludge to increase generation of biogas, in turn increasing renewable energy/fuel production in support newly adopted mandates under Senate Bill 1383 (reducing methane emissions across the state). However, the proposed Rule 11-18 may restrict use of biogas since its combustion may contribute to a slight increase in some toxic air contaminants, potentially forcing POTWs to purchase fossil fuel based electricity or natural gas. This would result in an increasing in fossil fuel based greenhouse gas emissions statewide and is in direct contradiction with the Governor's goals for 2020, 2030, and beyond. The practice of diverting this organic waste from landfills for co-digestion at wastewater treatment plants is increasing across the state making Rule 11-18 a significant factor in achieving these goals moving forward.

CASA recommends BAAQMD consider providing exceptions in Rule 11-18 for projects that contribute toward achieving state goals for

reductions in greenhouse gas emissions through the diversion of organic waste from landfills, and increased production of biogas for the generation of renewable energy or fuel.

3) <u>BAAQMD should consider cross-media environmental impacts</u>

POTWs are regulated by a number of different governmental agencies whose goals can result in contradictory impacts to the municipal wastewater treatment sector. While regulatory actions may be seen as effective when each media (air, water, land) is addressed separately, the deficiencies become evident when the regulations are viewed holistically for protecting the overall environment and public health. CASA hosted a cross-media roundtable with state regulatory agencies including the Air Resources Board in 2008 highlighting these issues. A regulatory checklist was developed as an outcome of that meeting which was intended to highlight cross-media issues during regulatory development. CASA would be pleased to provide a copy of the checklist to the BAAQMD. There are increasing concerns about cross-media impacts and the potential operational and financial effects they will have on POTWs that are trying to provide an essential public service while maintaining compliance with regulations supporting contradictory goals.

CASA recommends a holistic approach and asks BAAQMD to address the cross-media environmental impacts of the proposed Rule 11-18 and in future proposed regulations.

Thank you for the opportunity to comment on the draft Rule 11-18. CASA supports BAAQMD's intent to protect the Bay Area's air quality, but asks BAAQMD to carefully address our concerns. CASA also strongly supports the comments provided to you by the Bay Area Clean Water Agencies (BACWA). Please feel free to contact me with any questions at gkester@casaweb.org or at 916-844-5262.

Sincerely,

Greg Kester

Greg Kester
Director of Renewable Resource Programs

cc: Roberta Larson, Executive Director, California Association of Sanitation Agencies
Dave Williams, Executive Director, Bay Area Clean Water Agencies
Debbie Webster, Executive Officer, Central Valley Clean Water Association
Steve Jepsen, Executive Director, Southern California Alliance of POTWs

To: Bay Area Air Quality Management District – Victor Douglas

From: Cathy Helgerson – CAP – Citizens Against Pollution

Regarding Draft Comments – Regulation 12, Rule 16 Petroleum Refining Facility – Wide Emissions Limits and Regulation 11 Rule 18

Project Description

1.0 Project Description – 1.1 Introduction Paragraph 1 – States that Petroleum refineries are significant sources of harmful pollutants. Comment: This is very true and people are getting sick and dying.

Paragraph 3 - Mentions Communities for a Better Environment (CBE) and several associated operations have recommended that the Air District adapt new Regulation 12, Rule 16: Petroleum Refining Facility Wide Emissions Limits (Rule 12-16 or "Refining Caps Rule") This rule would set numeric limits on specific refinery emissions, Rule 12-16 would apply only to the Bay Area five petroleum refineries and three facilities associated with the refineries.

Paragraph 4 - Air District Recommends Regulation 11 Rule 18 would apply to all facilities whose emissions of Toxic Air Contaminants (TAC) may result in a significant risk to nearby residents and workers- this would include petroleum refineries. It goes on to state – The purpose of 1118 is to set Toxic Air Contaminant Caps for those facilities causing the highest health impacts across the bay area and to require these facilities to reduce that health risk.

Paragraph 5 – EIR – Environmental Impact Report it is said will cover both Rules. The Board of Directors could adopt either rule, both rules, or neither rule it would be up to them.

1.1.1 Draft Rule 12-16 – Reflects a policy recommendation from CBE and their associated organizations. The rule as proposed by CBE, would limit the emissions of climate pollutants and three criteria pollutants greenhouse gases (GHG's) particulate matter (PM), oxides of nitrogen (NOX), and sulfur dioxide (SO2) from petroleum refineries and three associate facilities. The Draft Rule would establish facility – wide emissions limits for the covered pollutants at each of the affected to ensure that each facility does not increase emissions due to changes in operation, crude or product slates, or increases in product production. Each facility emission limit would be set at maximum – annual emissions reported for that facility in the period from 2011 through 2015 with an additional allowance or "threshold factor" of seven percent over the maximum annual emission rate for each pollutant.

Comment; It mentions that each facility emissions limit would be set at the maximum – annual emissions reported for that facility in the period from 2011-2015 with an additional allowance or "threshold factor" of seven percent over the maximum annual emission rate for each pollutant. The facilities do their own reporting and submit reports how can we be sure that their reports are honest and accurate? The TAC – Toxic Air Contaminants Reporting Systems is not an enforcement agency it just states what the pollution levels of each pollutant that is not enough. The EPA TRI System if reporting is also a reporting system nothing else we need an enforcement agency system. If the EPA does not investigate the facility and its records to make sure the facility has sent in their reports the matter goes unnoticed. This happened to Lehigh Southwest Cement and Quarry they failed to report the emissions with the TRI System requirements and they were fined. The EPA Region 9 just happened to see if Lehigh had reported to the TRI Department their emissions levels and they had not. I asked the EPA if they were going to check each year to see if Lehigh sent in their reports and I was told that they could not. I believe because I was asking about Lehigh that the EPA decided to check into this and I am glad they did.

The emissions ae high overall and then to add an additional allowance or “threshold Factor” of seven percent over the maximum annual emissions rate for each pollutant is very wrong.

Question: How do these Regulations and Rules effect the Lehigh Southwest Cement and Quarry operation?

1.1.2 Draft Rule 11-18, as proposed by the Air District staff, would ensure that emissions of Toxic Air Contaminates (TACs) from existing facilities do not pose an unacceptable health risk to people living and working nearby. It states that the rule would require facilities with a cancer risk in excess of 25 in a million (25/M) to reduce that risk below (10/M). It mentions further reductions.

Comment: It states if the facility could not devise a means to reduce the risk below 10/M, the facility would be required to install best available retrofit control technology for toxic pollutants (TBARCT) on every significant source of TAC’s at the facility. Who can determine the cancer risks? There is no mention of any cumulative effects from all the pollutants this seems to be continually overlooked. The Best Available Technology determination on equipment is left up to the facility to explore. I would like to know can the Air District actually determine that Lehigh for instance has found the Best Available Technology. Lehigh Southwest Cement and Quarry is also operating under a grandfathered protection rule and the plant is old and has not been retrofitted and upgraded as it should be so the public suffers continually. They are also using Petroleum Coke to fire up and operate the kiln this product Petroleum Coke is a waste material of Petroleum and is also radioactive. I have been told that it is worse than coal there needs to be a better way. The public is suffering cancer it is at epidemic stages everyone is getting it and other health problems. The public must be protected from this ongoing pollution. There needs to be a 24/7 surveillance cameras set up at each facility to make sure that the polluters are not out of serious compliance. The film and reports off of the surveillance cameras and monitor reports should be relayed to the Air District and the EPA immediately. Lehigh Southwest Cement is spewing pollution they must be sited and or closed down by the inspector.

1.2 Agency Authority – California Environmental Quality Act (CEQA) mentioned. The Air District is the lead agency they will prepare a Draft Notice of Preparation (NOP), and Environmental Impact Report (EIR) and Initial Study (NOP/IS) to address the potential environmental impacts associated with the draft rules. Comment: It seems that a great deal of information has been left out of this draft. The problem of enforcement from the agencies is evident stronger rules must be administered along with real enforcement and that is just not happening.

1.3 Project Location – Santa Clara County is included so we must of course look at all for toxic pollutants (TBARCT) on every significant source of TAC’s at the facility.

Comment: Question – Who can determines the cancer risks and how is it really accurate? There is no mention of any cumulative effect from all the pollutants this seems to be always overlooked. The Best Available Technologies available seem to be not enough people are still sick and dying.

Lehigh Southwest Cement and Quarry is also operating under a grandfathered protection rule and the plant is old and has not been retrofitted and upgraded so that it can be considered under the New Plant Rules and Regulations. There needs to be methods to require a facility that is outdated with its facility to be required to upgrade otherwise the public is continually subjected to a lower standard which is dangerous. They are also using Petroleum Coke to heat the kiln which is a waste material of Petroleum and is also radioactive and a serious pollutant. The Question is how will this be monitored no mention of the serious effects of this waste material and the emissions coming from the kiln that is causing serious health problems. I have even heard that this Pet Coke is worse than coal someone needs to look into this matter.

The pollution from these polluters is creating serious climate change issues and things are getting worse and worse we the public must demand action from the agencies this matter cannot wait.

I live in Cupertino near the Lehigh Southwest Cement and Quarry, and the Stevens Creek Quarry both of these companies with their pollution is destroying the Silicon Valley, the SF Bay Area and my home. There is dust and pollution in the Air, Water and on and in the Soil causing horrible health problems and even death this must stop. This pollution cumulates in our bodies and is the cause of so many health issues and problems. Human life, aquatic life, animal life and even plant life are threatened by this pollution we must all take responsibility in this matter, and ask the agencies to enforce stronger restrictions on these polluters. The paying of fines due to their pollution is not enough closing down the facilities and putting the polluters in jail seems to be necessary in order to really protect the public. The companies write off the fines they pay as a way of doing business this is just outrageous and cannot continue.

This pollution in California and the world is causing the great drought we are experiencing and even thou we are having some rain it will not be enough. I also suspect the US Government and the State of California is seeding the clouds and I have viewed jet stream myself to that effect. The chemicals that the jets are emitting to the clouds to make rain are just that chemicals and they are harming the public with these chemicals this should not continue.

The Air District needs to look at what the dust and water pollution is doing to the Stevens Creek Reservoir, creeks and the aquifer below our valley and homes. This pollution has polluted our groundwater and the wells that bring our water to our homes.

The Air District should not just consider the air pollution issues going out into the air, but they must consider pollution in water and soil that is coming from the air. They must also work together with the other agencies to make sure that this pollution does not continue to destroy communities and our world.

1.4 Back Round – Draft Rule 12-16 would affect the five petroleum refineries.

Comment: First I would like to say that I feel so sorry for the poor people that are living right next door to these polluters it is just horrible. I do not know how they can breath and how they have survived. There needs to be a compensation made for their loss maybe paying for their hospital bills but of course once the agencies make them provide compensation then they would also be in line of large law suites.

There is proof out there that pollution causes cancer and other health problems and even death but it seems no one wants to explicitly attach that proof or information to the polluters. They are allowed to keep polluting because as in Lehigh Southwest Cement and Quarry we need cement and so it seems that cement production is more important than people's lives. I would also suppose that we need Petroleum Refineries for oil so again we are faced with a very difficult situation how do we mine for resources without polluting the public?

There needs to be new technologies provided out there and these new technologies must be implemented immediately in order to save lives. These Petroleum and Cement companies are very wealthy and rich and could pay for the Best Available Technology but how can we leave the decision up to them? They may not be willing to retrofit a plant as is the case with the Lehigh Southwest Cement and Quarry instead they do the least amount of changes hoping that no one will tell them they have to retrofit completely or build a new plant. They do not want to be under the Rules pertaining to new plants because with their old equipment they cannot meet the new standards.

I believe that a special Division or Department with the agencies should look at and really find out what is the very best equipment and technology available. The facilities must upgrade their facilities accordingly and if they cannot they must close their doors. If we can send a man to the moon then we should be able to stop pollution and climate change.

I was reading the letter from Don Bristol with the Phillips 66 Company commenting on the Regulations and Rules he mentioned that Refinery owners and operators including Phillips 66 have vested rights in currently held enforceable permit limits. The vested rights issues are killing us there needs to be a change in Government with the Rules and Regulations, so as to protect the public from this dangerous pollution. There must be stop to contamination of our Cities from the heartless polluters who care only about the profits and revenue gained by the production of their products.

Draft Rule 11-18 would affect up to 1,000 facilities that emit TAC's. The Draft States that the Air District has determined that these emissions need to be reduced in order to be more protective of public health. These facilities include data centers, petroleum refineries, a cement kiln, gasoline dispensing facilities act. These facilities emit a variety of TAC's that can adversely impact public health. TAC's include compounds such as diesel particulate matter (DPM), benzene, polycyclic aromatic hydrocarbons (PAH's) and, 1.3-butadiene.

Comment: The Drafted Rule 12-16 and 11-18 cover many dangerous pollutants but there is nothing in the Draft that mentions how the Air District will specifically implement these new Rules and Regulations. I would like to see a more involved description of the overall implementation strategy. Putting generalizations on paper is not enough I want expressive details. The TAC's list has been around for a long time and the pollutants and the levels of pollution has not been addressed the way it should be.

The people are sick and dying a great more needs to be done if humanity is to survive we need strong enforcement tactics and technology needs to catch up in order to protect the public. There is no real enforcement if polluters do nothing but pay a fine. The Government makes out financially from these fines, but pays later for the hospitalization of persons who are left to suffer from this pollution.

Trying to set caps on these polluters is not enough because it leaves out the cumulative effect. How do we know that these caps actually are set honestly? People are sick and dying things are getting worse and worse climate change is real what are we to do?

Page 6 States the regulatory approach for Draft Rule 12-16 and 11-18 are summarized below and include the following basic elements.

Regulation 12, Rule 16 part of the basic element states that each facility emissions limit would be set at the maximum-annual emissions reported for that facility in the period from 2011 through 2015, and include an additional allowance or “threshold factor” that would equal seven percent over the maximum for GHGS, PM2, PM10, NOx, and SO2.

Comment: The Annual Emissions Inventory with the facility-wide emissions limits for each covered pollutant are set at what they are why would we want to start there? The facilities report their own emission levels like the fox watching he chickens how do we know what they are reporting is honest? There needs to be standards that actually stop the pollution and these standards actually protect the public. It seems that the maximum-annual emissions are set to allow the facilities to continue to produce their products because if the levels were lower the facility may not be able to operate. The real goal is to develop technology that will eliminate pollution overall with zero emissions wishful thinking yes but necessary. It seems the Regulations and Rules sure look good on paper can are they do the job.

1.5 Proposed Project Description – the description of Draft Regulation 11, Rule 18 and regulation 12, Rule 16 are provided below.

1.51 Regulations 12 rule 16

1.5.1.1 Pollution Coverage – The Draft Refining Cap Rule would limit the emissions of climate pollutants (GHG’s) and three criteria pollutants (PM-both PM10 and PM2.5, NOx, and SO2) from refineries and other refining related facilities to a specific baseline plus and allowance; there by establishing a “CAP” for each of these emissions facility could not exceed.

Comment: Greenhouse Gases (GHGs) is real Lehigh Southwest Cement and Quarry contributes to this problem especially with the burning of Petroleum Coke how will this problem be solved? It would take the development of new technology and new thinking coming into place.

The agencies are not working together to stop this ongoing pollution and they seem to think that just lowering the pollution levels in their eyes is enough how can that be when so many people are sick. I will continue to mention the cumulative effect and how this plays into the serious health issues. There is also the Chemical Cocktail mixing of pollutants combining these pollutants makes them even more hazardous and dangerous.

Particulate Matter PM is also a complex issue there is an assortment of Tiny Airborne Particles that vary in size and mass (ultrafine, fine and course, physical state (solid or liquid), chemical compositions, toxicity, and how they behave in the atmosphere.

Comment: These Airborne Particles are destroying our lungs, bloodstream, brain and other vital organs, and individual cells. They trigger asthma attacks, chronic bronchitis, impaired lung development in children and adults, heart attack, stroke, and premature death. If the agencies know all this than why is it that the pollution still is allowed to flow into our cities and homes.

Nitrogen Oxides (NOx) – States these contaminants can damage vegetation and negatively impact the health of humans and animals.

Comment: Cancer in humans and animals is on the rise it is at epidemic stages, two out of three people are getting cancer. We must stop this pollution, or all of us will have health problems and will die as a result of this pollution. It mentions how this pollution can harm vegetation trees that are so valuable to our existence and our vegetable gardens what we eat is also becoming contaminated.

The dust from Lehigh Southwest Cement and Quarry and the Steven Creek Quarry is every place contaminating the Air, Water and Soil where we live. The dust is even eating the paint off of my car can you imagine what it is doing to our bodies.

Sulfur Oxides (SOx) – Heating and burning fossil fuels (such as coal and oil) release the sulfur present in these materials causing major air pollution problems the most common sulfur oxide is SO2.

Comment: This heating and burning of fossil fuels which can form Sulfur Oxide and in turn cause sulfuric acid in the presents of moisture. This process causes acid rain which causes all kinds of problems to our environment and to human existence.

1.5.1.2 Affected Facilities – Lets no limit it to just those.

1.5.1.3 The Emissions Units – Comments: Do not use old data maximus – year actual emissions reported in 2011-2015 plus additional allowances or threshold factor, of seven percent that is intended to account for normal year – to – year variations in emissions. There needs to be real life saving levels taken from monitors used for this purpose to record actuals to date emissions levels. The facilities report the levels themselves and submit them to the Air District so how can we be sure that the levels they report are accurate or honest? The problem with the Air District is they have to lower emissions to the point of allowing Lehigh and other polluters to continue to operate, so if the levels are to low and they cannot operate the Air District must allow higher levels of pollution to be emitted. I am sorry but my solution to the problem is to close down the Lehigh Cement and Quarry and the Steven Creek Quarry and clean up with a Super Fund Site once cleaned turning the properties into State and or Federal Parks.

Table 1 – The Enforceable Emission Limits on Refinery – Wide Emissions – Comments: This table reflects the information tables sent to the Air District by the Facilities themselves. Regulation 11, Rule 18 States that the Air District would screen all facilities that report toxic emissions and conduct health risk assessments (HRA) for facilities with a cancer risk prioritization score of 10 or greater or a non cancer

prioritization score of 1.0 or greater. The HRA's would incorporate the New Office of Environmental Health Hazard Assessment (OEHHA) protocol and health risk value adopted in March 2015, the Risk Management Guidelines adapted in July 2015 by the California Air Resource Board (ARB) and the California Air Pollution Control Officers Association CAPCOA) and the revised Air District HRA guidelines. It talks about the first phase of the rule, facilities that pose a cancer risk in excess of 25/M or a chronic or acute hazard index in excess of 2.5 must either reduce the facility cancer risk below 10/M and reduce the chronic and acute hazard below 1.0; or install TBARCT on all significant sources of toxic emissions. In the second phase, facilities not already addressed in the first phase that pose a health risk in excess of 10/M or a chronic or acute hazard index in excess of 1.0 must either except GHGs, which are based on 2011 through 2014 emissions due to the current unavailability of 2015 data reduce the facility cancer health risk below 10/M and reduce the chronic and acute hazard indexes below 1.0; Install TBARCT on all significant sources of toxic emissions.

Comment: The Air District is not clear on a TBARCT Installation this should be explained in the draft clearly. The question is with regards to enforcement how will all of this be enforced this definitely needs to be spelled out in order to make sure that the public is truly protected. It seems to be extremely evident that no one really knows if this will really work or not and seems to be impossible. If this was ever possible why had the agencies not implemented it before? I believe with the present technologies that there is no way a polluter like Lehigh can reduce emissions to accommodate these rules. The public is also asked to wait till 2020, 2030 or even longer to finally complete the requirements. The public's health is in grave danger and we keep pushing the years further out till a person really wonders if it will ever really happen. How can we also think that the information compiled from the facilities and the Air District is honest and correct? The facilities may lie about the emission reports they turn in in order to save themselves. We cannot use these levels to determine CAPS there needs to be a health and safety real limits set. I think that until we can stop or control the emissions completely that the public will always be at risk of serious health issues and even to the point of death.

1.5.14 – Changes in Monitoring Methods – The proposed rule would incorporate a means to address potential changes in the quantities of emissions reported due solely to changes in monitoring methodologies to ensure constant compliance with the emissions limits.

Comment: The changes in the monitoring Methods should be again spelled out in the report and they are not my question is why not? There would need to be new and advanced technologies implemented because what is in place is not working. The TRI reporting system is flawed and really without merit. It is susceptible to very incorrect information submitted by Lehigh and other polluters. I was informed by the Air District that the facilities even add to the pollution levels they say they are emitting so as not to be called by the EPA. I find this hard to believe, but who knows what is really taking place if Lehigh and other polluters are sending in their own information and the EPA is taking this information and putting it in the TRI System. Note: The TRI System is hard to access and very difficult to read this needs to change.

The public needs to see that the information coming from the facilities is real. The monitors put in place at the facilities need to report directly to the Air District and the EPA. The information must be reported truly and honestly and there should be no way that the facilities can lie about their pollution. Once this information is registered off of the monitors at the facilities and there is a violation the Air District inspectors need to go out and write up the polluters right away. There should be fines imposed and also a possibility that the facility can be shut down until they are in compliance. If the facility cannot control their emissions and they are always out of compliance then they should be shut down.

1.5.2 Regulation 11, Rule 18

1.5.21 Administrative Procedures – It states that the Draft Toxic Risk Reduction Rule would utilize the annual toxic emissions inventories reported to the Air District by sources that emit toxic compounds. From the Toxic Emissions Inventory date, Air District would conduct a site-specific Health Risk Screening Analysis (HRSA) in order to assess the potential for adverse health effects. From these HRSA; the Air District would categorize each facility to determine cancer risks

Comment: There seems to be again no mention of the cumulative effect levels that should determine the cancer risk from ongoing pollution exposures. Number scores do not reflect the real danger.

1) Basing the amount of toxic pollution emitted from based on reports submitted by the facility is endangering the public. How do we know based on the TAC and TRI reports if in fact they are reporting honestly? The need for installing surveillance equipment is evident and should be put on each facility's recording equipment. The emissions information should be relayed from each monitor to the Air District and the EPA directly without delay. The inspector is available 24/7 and is able to go right away to stop the emissions that are causing the violation. The inspectors are not available after 5:00 PM Monday through Friday and also not available Saturday and Sunday this is leaving the public subjected to dangerous pollution. The inspector may have to shut down the facility completely until the violation can be corrected and if it cannot the facility should be closed for good.

2) There is another serious matter that needs to be taken into consideration and that is the cocktail effect mixing all these pollutants together is forming an even further danger to the public and it must stop. There needs to be more research done on this effects and it needs to take place soon, again to protect the public who are not aware of the dangers and leave their lives in the hands of the agencies.

3) Proximity of the facility the Lehigh Southwest Cement and Quarry and the Steven Creek Quarry are very near a large populous The City of Cupertino especially is subject to thousands and thousands of pounds of pollution coming from the Lehigh Southwest Cement and Quarry and the Steven Creek Quarry. The Air, Water and Soil is completely contaminated with this pollution and it is a grave danger to the public, this matter goes completely unnoticed by the Agencies, Cities, County and the General Public. I attended a meeting in Cupertino at the Cupertino City Hall sponsored by Santa Clara County. Joe Simitian a Board member was hosting this meeting. This meeting was only a tip of the iceberg a great deal of information was never brought up and discussed. The meeting is not an open forum and the public pretty much has a gag order not to speak at the meeting. The public is allowed to submit cards and then the SCC Staff and Joe Simitian decide what cards are to be considered for discussion and how. This in my opinion this is not what our Democracy was based on and I am appalled, dismayed, disheartened and disappointed with all the agencies that will not stop the pollution and continue to let the polluters go on polluting our cities. The playing down by the agencies of the seriousness of this

pollution is more than a person or persons can take and it needs to stop. The hiring of police and strong arm men to guard the agencies personnel and Santa Clara County representatives from anyone who would speak up and tell the truth at meetings is a disgrace. I must say that something needs to be done about the lingering complacency that the agencies keep presenting to the public Lehigh Southwest Cement and Quarry and the Steven Creek Quarry are not in compliance.

The analysis it is stated in order to complete the work in a timely manner that an independent contractor must be hired. I am concerned how do we know the work will be conducted accurately and honestly?

4) It states that any other factors that the Air District deems to be important.

Comment: Well than I would like to include the Ammonia emissions coming from the Lehigh Southwest Cement and Quarry which should be considered a serious pollutant and the Air District seems to think it is not. The Ammonia is added to control the NOX this is a danger to the public and it is not properly regulated. The TAC listing of pollutants and their acceptable levels does not really reflect the serious damaging pollution that is going out into the public again taking into cumulative effect is left out and the public suffers.

It states the Air District would compile two lists of facilities and determine the cancer risks to children and infants,

Comment: It does not mention and what is seriously left out is the damage these pollutants cause to the fetus. The pollution causes many birth defects and even death to the fetus and young children. I know the damage done to my unborn fetus first hand my daughter was born with brain damage and only had brain stem functioning, she suffered greatly, was hospitalized 28 times, for weeks at a time and finally died at 3-1/2 years old. They said she died from toxic shock syndrome and I believe that the pollution coming from Lehigh Southwest Cement caused this problem. There is gray dust all over my home and property, and I am subjected to breathing it into my lungs and eating this dust. This dust is also taking the paint off of my car which acts like sand paper. The pollution is affecting the Air, Water and Soil and the Air District can no longer play down the terrible health issues that this pollution is causing the public. When my daughter was born they had to perform an emergency C-section on me and I could have also died and I have the scar to remind me of this time. I have had cancer twice and have lost both breasts after three surgeries. I have asthma, diabetes, planters’ foot and must also take a pill that kills the estrogen in my body to keep the cancer from coming back.

My husband had cancer and suffered from serious depression he died 3 years ago from Coronary Arrest, Liver Disease, and Alcohol abuse. My dog also died of cancer to the liver years ago and I believe that this was also caused by the Lehigh Southwest Cement and the Stevens Creek Quarry that are polluting the Air, Water and Soil in the Silicon Valley and the SF Bay Area. My son was diagnosed with Dyslexia and Add I call him my miracle son because I had infertility problems and suffered two miscarriages all of this I attribute to the pollution with the above polluters.

1.5.222 Health Risk Assessments – It states that a HRA (Health Risk Assessment consists of four basic steps: 1) Hazard identification; 2) Exposure Assessment, 3) Dose Response Assessment; and 4) Risk Characterization. The Air District conducts HRAs using standardized mythologies for each of these steps.

Comment: The question is how can these four basic steps be determined if the polluters monitor themselves? The polluters turn in their own reports and also calibrate their own machines and monitors so how can we be sure they are telling anyone the truth? The determination of all four basic steps that would consist of a Health Risk Assessment would have to include doctors and scientists that would be able to add their statistics. There would need to be an intense honest investigation that would show all functions of testing that would include the cumulative effect in order to keep the public from harm. There are many things left out of the investigation processes and it is very important that the public is informed of the true levels of pollution that is seriously affecting them.

1.5.2.3 Pollutant Coverage – The Toxic Risk Reduction rule would address TAC emissions from existing stationary sources.

Comment: I believe until the Air District and the other agencies really do their own testing with their own monitors that cannot be tampered with that it is impossible to really know what is really being emitted from the polluter facilities. The pollutants mentioned are very carcinogenic – Benzene, 1,3-Butadiene, Polycyclic Aromatic Hydrocarbons (PAHs) and Diesel Particulate Matter (DPM) but there are many more. The cocktail and the cumulative effect is a serious matter and again nothing is mentioned in the Draft this should not be overlooked.

1.5.2.4 Source Coverage

Comment: Let us not forget the Lehigh Southwest Cement and Quarry in Cupertino that is polluting the Silicon Valley and the SF Bay area. The Toxic Health Reduction Rule will need to be fine- tuned and specializing in the elimination of the pollution as a whole. Reducing emissions in anyway will not solve the serious problem of the cumulative effect. The pollution is harming humans, animals and aquatic life we the people need to request that our Government invest in new technologies that will eliminate pollution completely. Is this wishful thinking I suppose so but after all we sent a man to the moon we should be able to resolve this problem. The economic issues should not be holding back the saving of people’s lives and the planet from pollution, climate change and the drought here in California.

The 6,000 facilities out there should all be considered for regulating but the Air District as only mentioned 1,000 facilities. The Rule and Regulation looks good on paper but what will it really mean to the public especially if it is many years down the line. The public suffers health issues while the Air District try to figure out what to do and how to do it this should be the highest priority and it is not. The reason given is due to the lack of funding and manpower we just can’t do the job faster. What is wrong with our Government why are not seeing that everyone is getting cancer other health issues and even death?

The problem has been that there really is no real enforcement the facility in violation just pays a fine and then go right back to polluting again writing off the fine as a cost of doing business. It seems no one will stop the crimes that are being committed against the people no one ever goes to jail. The future of humanity is at risk and all the agencies seem to do is try and postpone, delay and refuse to really impose penalties against the Lehigh Southwest Cement and Quarry and the Stevens Creek Quarry. When there is any kind of fine most of the money goes back to the Government. Santa Clara County even refuses to impose a fine on Lehigh because of the tax revenue and the property tax revenue they receive each year. The public is not so blind that we do not see what is really taken place.

The biggest problem we face here in the Silicon Valley is that Lehigh Southwest Cement and Quarry run out of limestone and decide to put in a new quarry pit which will destroy 30 thousand trees and 600 acres of land. This will also destroy the homes for many animals who live in th

Please remember there is no one who is immune to cancer and the other health problems we are or will be all suffering. Cancer cases are at epidemic levels everyone will be getting it and the other serious illnesses. The human race will be lost if we do not change the way we do business and save the planet it is our home the only one we have and everyone needs to be involved. The planet will be here in 50 years but will the human race I suppose that is up to each and every one of use to start to SAVE THE PLANET NOW!

I hope that the Air District will really take the time to not only read my comments but that they will also ask the same questions and use the information to change the way that they think about pollution. I also hope anyone reading my comments will get even more involved and also that you will be telling and helping others to do the same.

Please save the Silicon Valley and the SF Bay area from the Lehigh Southwest Cement and Quarry and the Stevens Creek Quarry by creating a movement to shut them down. My dream is to have the State or Federal Government buy the properties via eminent domain, issue a Super Fund Cleanup, and then turn the properties into State and Federal Parks. I would like to address the public if you are reading my comments and feel the same way I do please contact your State and Federal Representatives.

Thank you,

Communities for a Better Environment
Sierra Club San Francisco Bay Chapter
350 Bay Area
Asian Pacific Environmental Network
Sunflower Alliance
Richmond Progressive Alliance
Crockett-Rodeo United to Defend the Environment
Benicians for a Safe and Healthy Community
Rodeo Citizens Association
Interfaith Climate Action Network of Contra Costa County
Community Science Institute—CSI for Health and Justice!
Greenaction for Health and Environmental Justice
California Nurses Association

11 November 2016

Eric Mar, Chair of the Board
John Gioia, Stationary Source Committee Chair
Members of the Board of Directors
Bay Area Air Quality Management District
375 Beale Street, Suite 600
San Francisco, CA 94105

Attention: Jack Broadbent, Air Pollution Control Officer
Gregory Nudd, Air District staff
Eric Stevenson, Air District staff
Victor Douglas, Air District staff

Re: **Initial Study (IS) Released 14 October 2016 and Draft Staff Report (DSR) Released 27 October 2016 for Proposed Rules 12-16 and 11-18, and Request for Comment on Scope of California Environmental Quality Act (CEQA) Review**

Dear Chair Mar, Committee Chair Gioia, and Board members,

Communities for a Better Environment (CBE), the Sierra Club, 350 Bay Area, the Asian Pacific Environmental Network (APEN), the Richmond Progressive Alliance (RPA), the Sunflower Alliance, Crockett-Rodeo United to Defend the Environment (C.R.U.D.E.), Benicians for a Safe and Healthy Community, the Rodeo Citizens Association (RCA), the Interfaith Climate Action Network of Contra Costa County, the Community Science Institute—CSI for Health and Justice!, Greenaction for Health and Environmental Justice, and the California Nurses Association (CNA) comment on the Initial Study, Draft Staff Report, and request for scoping comment cited above in support of proposed Rule 12-16.

Introduction

Oil refining is the largest industrial emitter in the Air District's jurisdiction of the most harmful types of air pollution known—fine particulate matter and greenhouse gases. Four years ago the Air District admitted there is ***no limit*** on refinery-wide emissions, found refining lower quality oil could ***increase*** refinery emissions, and planned to set up, by June 2013, a backstop to ***prevent*** that foreseeable emissions increase. The enforceable emission limits in proposed Rule 12-16 would "cap" these emissions to set that backstop. Setting these limits is urgent as the oil industry's push to build long-lasting infrastructure for inherently higher-emitting grades of oil threatens imminent and irreversible harm.

We appreciate the District staff's recent work to develop the specific numeric limits now proposed in Rule 12-16, and the Board's direction to its management to complete a full analysis of this measure. Rule 12-16 is reasonable, effective, a necessary complement to other air quality and climate protection measures, and urgently needed. It would close a gaping loophole that has left facility-wide emissions from oil refineries unlimited. It is needed to prevent the biggest industrial emitters of the most harmful air pollutants known from causing severe and irreversible climate and health impacts by locking in bottom-of-the-barrel oil infrastructure that could increase those emissions for another generation.

However, the Initial Study and Draft Staff Report released by District staff management present grossly inaccurate, biased, and misleading analysis that must be corrected. They assert conclusions regarding the need for Rule 12-16, its effectiveness, and your authority to adopt it that are proven false by factual information they fail to disclose or analyze. Worse, as we document herein, this crucial information that is omitted and ignored includes facts the District already knew, and even its own previous findings.

Oil industry pressure has affected the timing and transparency of this rule development process. Air District staff management has long delayed this urgent measure to keep refinery emissions from increasing, telling the public only that it was explaining secretly, in closed sessions with its Board, why it agreed with the oil industry's claim that refinery emissions must be allowed to increase. Now the excuse for that delay appears to be only the false conclusion of analysis biased by systematic nondisclosure of relevant facts.

As you know, the Air District Board has directed its staff to complete a full analysis and rule development package for Rule 12-16 that the Board can properly consider for adoption as expeditiously as possible. We hope to stand with the Air District Board in continuing to demand disclosure and consideration of all information that is relevant to a full analysis of this measure, as required by scientific principles and the California Environmental Quality Act (CEQA).

The Air District developed Rule 12-16.

Finding that a switch to lower quality grades of oil could increase refinery emissions significantly, the Air District initiated rulemaking to set a "backstop" against increasing refinery emissions in 2012[1] and resolved to develop Rule 12-16 for this purpose in 2014.[2] After considering extensive public comment on many options for this backstop, the Air District decided to consider setting the performance-based emission limits now proposed. Meanwhile, this air district and others had already been managing and updating their criteria for the facility health risk assessment and risk reduction program contemplated by proposed Rule 11-18, for decades, pursuant to the state law that established this program, and without the need for rules like Rule 11-18.[3]

Concealing these facts,[4] the Initial Study (IS) and Draft Staff Report (DSR) label Rule 12-16 as a recommendation by "CBE and associated organizations" only, and Rule 11-18 as the District staff's new idea. This error presents an incomplete, inaccurate, and biased description of the rules that hides information about the need for them, the Air District's role in developing them, and its multi-year rulemaking record for Rule 12-16 that must be known to complete accurate analysis under CEQA.

Rule 12-16 addresses extremely harmful air pollution.

Particulate matter (PM) and greenhouse gas (GHG) air pollution cause the worst current and potential local, regional, and global harm of all the air pollutants known. A strong scientific consensus holds that failure to curb GHG emissions quickly could lead to climate impacts so extreme that human societies as we know them might become untenable,[5] and the Air District itself has reported elsewhere that:

> Exposure to $PM_{2.5}$ is by far the leading public health risk from air pollution in the Bay Area, accounting for more than 90 percent of premature mortality related to air pollution. *Bay Area Air Quality Management District, 2016.*[6]

Incredibly, the IS and DSR fail to disclose the full extent of known and potential PM and GHG impacts, even though Rule 12-16 would limit GHG and PM air pollution. These extremely severe existing and potential effects must be disclosed in CEQA review. Moreover, this error inserts a further bias into the IS and DSR analyses because the approach they inappropriately portray as an alternative to Rule 12-16, proposed in Rule 11-18, does not control GHG or $PM_{2.5}$.[7] The DSR simply cannot credibly conclude, as it purports to conclude in this inappropriate comparison, that preventing increases in the most harmful emissions is less protective than allowing those emissions to increase.

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[1] Regulatory Concept Paper, Petroleum Refining Emissions Tracking Rule. Draft: May 30, 2012.

[2] Resolution 2014-07, adopted unanimously by the BAAQMD Board 15 October 2014.

[3] *See* BAAQMD, 2013. Toxic Air Contaminant Control Program Annual Report 2013.

[4] Such errors were not corrected despite prior comment: *See* CBE's 11 Sep. 2016 comments.

[5] *See* Fifth Assessment Report (AR5), Intergovernmental Panel on Climate Change (IPCC), 2014.

[6] Draft Control Measure SS1: Fluid Catalytic Cracking in Refineries, 2016 Clean Air Plan and Regional Climate Protection Strategy (quoting the Air District's 2010 Clean Air Plan).

[7] Nearly thirty years after the State Toxic Hot Spots Program began there is still no defined method for Rule 11-18 health risk assessments to include $PM_{2.5}$, as the DSR admits at 39.

Rule 12-16 limits exceptionally harmful polluters.

Oil refining emits more GHG and PM than any other industrial sector in the Bay Area.[8] Indeed, the summary figures in the DSR, indicating that the five major refineries here collectively emit 45% of $PM_{2.5}$, 34% of NOx, 51% of SO_2, and 38–67% of the GHGs[9] emitted by all industrial sources in the region combined, are consistent with this finding. But omitting this comparison of industrial sectors despite the fact that different sectors require different technologies and control measures, the IS and DSR obscure this finding.

The portrayal in the IS and DSR of refinery emissions as smaller than mobile source emissions presents an inaccurate and misleading comparison because it conflates source categories in two important ways. From a District rulemaking perspective, it ignores the fact that the District has authority to control refinery emissions, not tailpipe emissions. Equally important for environmental health and climate protection, it ignores the link between emissions from refiners' production and their products.

Accounting for the polluting products refiners profit from in competition with cleaner alternative fuels, even the DSR's partial estimates link Bay Area refineries to 46% of $PM_{2.5}$, 87% of NOx, 57% of SO_2, and 56% of the GHGs[10] emitted by all sources in the region. From the perspective of preventing unsustainable and irreversible climate impacts, these figures indicate that achieving the 40% emissions cut required by 2030 and the 80% cut required by 2050 could become impossible in the Bay Area if long-term increases in refinery emissions are allowed to become locked into place now. The need for refinery emissions control analysis to address this environmental effect context is beyond reasonable dispute, but the IS and DSR omit and ignore this context.

By protecting frontline communities Rule 12-16 protects everyone.

Abundant evidence in the District's rule development record demonstrates that refinery emissions disparately impact nearby low-income communities of color. Some examples:

- At a distance of 2.5 miles away the average areal emission intensity (e.g., tons/mile^2) of Bay Area refinery $PM_{2.5}$, NOx, and SO_2 emissions is 3–30 ***times*** that for ***all*** emission sources within the Bay Area, averaged over the region as a whole.[11]
- Peer reviewed measurements show that refinery emissions contribute significantly to locally elevated outdoor ***and*** indoor $PM_{2.5}$ air pollution concentrations outside ***and*** inside the homes of low-income residents of color in Richmond.[12]
- Analyses of Air District data link locally elevated hourly air concentrations of SO_2 and H_2S to episodic emissions from Bay Area refineries.[13]

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[8] Based on District and ARB data: _See_ CBE et al. 9/21/15 comments in rules 12-15/12-16 record.

[9] GHG range accounts for GHG from electricity generation elsewhere to supply the Bay Area.

[10] GHG estimate accounts for GHG from electricity generation elsewhere to supply Bay Area.

[11] Based on District emissions data: _See_ CBE 11/23/15 comments in rules 12-15/12-16 record.

[12] _See_ CBE 11/23/15 comments in rules 12-15/12-16 record, and Attachment 44 thereto.

[13] _See_ CBE 11/23/15 comments in rules 12-15/12-16 record, and attachments 45 and 46 thereto.

- Refineries are strong sources of ultra-fine PM that, compared with coarser PM, has a more toxic composition, penetrates deeper into the lungs, bloodstream and cells, and is more abundant and concentrated in ambient air near its sources.[14]
- Fallout from large, visibly unmistakable "black smoke" PM plumes caused by Chevron's Richmond Refinery Crude Unit fire of 6 August 2012 forced ≈ 15,000 people to seek emergency room care in Richmond and surrounding communities.[15]

Ignoring all this evidence, however, the IS and DSR argue against significant localized impacts of refinery emissions, asserting a grossly incomplete and inaccurate analysis that insists on misleading "facts" based on assumptions the District knows to be false. The District knows that accurate analysis of the dispersion of emitted pollutants in the ambient air must account for the amounts of those pollutants emitted, but the IS omits and ignores this source-strength factor despite prior comment[4] pointing out the error. Correcting this error would reverse its false conclusion that the emissions accumulate only in the ambient air of the region's inland valleys instead of accumulating in those locations ***and*** near the bayside refineries, in nearby residents' ambient and indoor air.

Worse, the District knows its regional ambient air monitoring network was not designed to measure, and does not measure, air hot spots near refineries and other strong emission sources reliably and accurately—but the DSR asserts that these regional monitors do just that in its false argument against significant localized refinery emission impacts. This is the same error that led Air District management to assert that Chevron's August 2012 fire caused no significant air quality impact while thousands rushed to hospitals choking on Chevron's air pollution. The regional monitors were not set up to measure the local air impacts of that incident and did not measure those impacts.[16] In fact, the District decided to make the refiners pay for new monitoring of nearby ambient air based on its own findings[17] that its regional monitors do ***not*** say what the DSR now claims they say.

Rule 12-16 prevents clearly foreseeable harm.

The Air District has ample evidence to support its finding[2] that a switch to lower quality oil threatens to increase refinery emissions significantly. Peer reviewed science shows that the severe processing needed to maintain engine fuels production from lower quality oil increases refinery energy intensity, thereby increasing refinery emissions of combustion products including GHG, PM, NOx, and SO_2.[18] Refining greater amounts of bitumen-derived "tar sands" oil would further lower the quality of the average Bay Area refinery crude feed.[18] The oil industry reports plans to refine more tar sands oil here,[18] and multiple projects for new or modified infrastructure enabling those plans have been proposed for imminent construction across the regional oil industry.[19]

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[14] *See* CBE 10/21/15 and 11/23/15 comments in the rules 12-15/12-16 record, including attachments 6, 42 and 43 and *esp*. 4 (Air District corroboration of these findings).

[15] *See* CBE 11/23/15 comments in the rules 12-15/12-16 record, *esp*. Attachment 47 thereto.

[16] *See* San Pablo–Rumril Station data (https://www.arb.ca.gov/adam/weekly/weeklydisplay.php).

[17] *See* Rule 12-15 rulemaking record.

[18] *See* CBE 10/21/15 comments in the rules 12-15/12-16 record, including attachments thereto.

[19] *See* CBE et al. 6/10/16 comments in the rule 12-16 record, and BAAQMD permit files.

Further wounding the Air District's credibility, however, the IS and DSR dispute the District's own finding that an oil switch now threatens to increase refinery emissions significantly[2] by dismissing the likelihood, severity, and timing of this threat while omitting and ignoring the evidence the District possesses that supports this finding. The IS only mentions the objective of Rule 12-16 to prevent potential increases in refinery emissions due to changes in refinery oil feed quality (twice: _see_ IS at 1-3, 1-10), omitting and ignoring evidence in the District's record and even this finding. The DSR's cursory discussion of this potential toxic and climate threat goes further, labeling the threat only theoretical and small (DSR at 6, 8), and omitting the potential emission impacts and benefits from preventing these impacts from its analysis, then falsely concluding that Rule 12-16 would have little or no benefit. (DSR at 20, 24, 39, 40).

Again, the IS and DSR improperly omit and ignore evidence the District already has that, when properly reported and analyzed, reverses their false conclusions about Rule 12-16.

Rule 12-16 prevents irreversible harm.

Allowing refinery emissions to continue at current rates or to increase through 2030–2050 could foreclose the opportunity to meet critical climate and health protection targets in the Bay Area. (_See_ page 4 above.) Crucially, the "infrastructure inertia" created by major capital projects for new fossil fuel plants represents a commitment to new and continuing emissions for 30–50 years,[20] a dead-end in the path to a sustainable climate,[21] and a fundamental threat to future generations' environment and economy.[22] The District has acknowledged that Bay Area refineries are likely to switch crude slates,[23] that a switch to higher-emitting oil could be inextricably linked to new infrastructure projects[24] like those they now plan,[25] and that this new refinery infrastructure can be expected to have the capacity to operate for several decades.[26]

Thus, enabling the industry's planned switch to higher emitting oil feedstock and the long-lasting new infrastructure to refine it by allowing refiners' emissions to increase now could result in irreversible climate and health impacts. Therefore, one of the key objectives of proposed Rule 12-16 is to:

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[20] _See_ Davis et al., 2010. Future CO_2 emissions and Climate Change from Existing Energy Infrastructure. *Science* **329:** 1330–1333. DOI: 10.1126/science.1188566.

[21] _See_ Williams et al., 2015. *Pathways to Deep Decarbonization in the United States;* Energy+ Environmental Economics (E3). California ARB Chair's Presentation Series, 13 May 2015.

[22] Professor Lord Stern's 28 October 2016 speech to the Royal Society entitled *The Criticality of the Next 10Years: Delivering the Global Agenda and Building Infrastructure for the 21st Century.*

[23] 2016 CAP Draft Measure SS9 ("crude slates being refining by Bay Area refineries have been changing recently, and they are expected to continue to change in the future as California's crude oil resources start to become depleted and refineries look to other sources of crude oil.")

[24] _See_ DSR at 8 ("The refineries would likely need to make changes to their facilities in order to accommodate different sources of crude oil with different compositions while maintaining current production levels.")

[25] _See_ CBE et al. 6/10/16 comments in the rule 12-16 record, and BAAQMD permit files.

[26] _Id_. (_esp_. project descriptions in EIRs that BAAQMD permits are based upon).

> Compliment other climate, health, and safety measures, by ensuring that new commitments to long-lasting infrastructure for refining higher-emitting and more hazardous oils, which could foreclose the long-term emission reduction and safety potential of these other measures, will not be encouraged or enabled by allowing Bay Area refinery GHG, PM, NOx, or SO_2 emissions to increase.[27]

Despite purporting to compare Rule 12-16 with other policies which would not close the loophole allowing refinery-wide emissions to increase, and would thereby allow this infrastructure inertia impact, the IS and DSR ignore this irreversible impact, omit any analysis of infrastructure inertia, and fail even to mention[4] the objective quoted above.

Rule 12-16 is a necessary complement to other policies.

Rule 12-16 would set numeric limits on facility-wide emissions of GHGs, $PM_{2.5}$, PM_{10}, NOx, and SO_2 from refinery energy use at levels that prevent any significant increase in those emissions, thereby supporting the ability of other policy measures to cut harmful air pollution. The IS and DSR, however, present a false comparison of this rule with those other policies that is based on incomplete, inaccurate, and misleading analysis.

First, the IS and DSR omit a key fact that the District knows: ***no*** other policy sets any limit on facility-wide mass emissions from any Bay Area refinery.[1] Thus, no other policy addresses the irreversible refinery infrastructure emissions impacts described above,[20–27] which the IS and DSR also fail to disclose. These omissions obscure a unique and critical role of Rule 12-16 among air quality, environmental health and climate policies.

Second, the IS and DSR assert potential impacts of Rule 12-16 based on incomplete, misleading, and false comparisons with New Source Review (NSR) and cap-and-trade. NSR may not detect emissions increases from refining lower quality oil[28] and exempts too many refinery sources to prevent the significant increases in facility-wide emissions switching to lower quality oil could cause, necessitating a backstop against increasing refinery emissions,[1] District staff has found. Rule 12-16 would set such a backstop. California's cap-and-trade policy allows refineries to increase emissions using credits, gives them credits free, and is not authorized beyond 2020,[29] so it cannot address the irreversible infrastructure impacts Rule 12-16 addresses. Further, unlike Rule 12-16, cap-and-trade does not provide multi-pollutant combustion emissions control, which District staff has found to be more effective and efficient than pollutant-by-pollutant measures.[30] Finally, AB 197 requires prioritizing efficient direct control measures—like Rule 12-16.

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[27] _See_ CBE's 11 Sep. 2016 comments on the draft Rule 12-16 project description at page A-8.

[28] 2016 CAP Draft Measure SS9 at 2 (modifications to change crude slates "may be difficult or impossible for the Air District [and the public] to discover … Refineries are complex operations, and any modifications associated with crude slate changes may be relatively subtle and not immediately obvious. ... Air District staff is investigating potential amendments to … include any significant crude slate change" among the triggers for NSR review of such modifications.)

[29] _See_ ARB's *Preliminary Draft Proposed Regulation Order and Staff Report* dated 1 July 2016.

[30] _See_ 2016 CAP Draft Measure SS11 at 2.

The IS and DSR omit and ignore all of this information which, when considered, reverses their inaccurate conclusion that Rule 12-16 could conflict with NSR and cap-and-trade.

Third, the IS and DSR present a false comparison of the proposed rules' effectiveness. Proposed Rule 11-18 would not address emissions of PM or GHGs that Rule 12-16 would address. Equally important, Rule 11-18 could not prevent the imminent and potentially severe emission impacts that Rule 12-16 could prevent, because Rule 11-18 would use a reactive approach that waits for further health assessments before beginning, well after 2020, to consider applying emissions control. The IS and DSR omit and ignore this information that shows Rule 11-18 cannot substitute for Rule 12-16—a fact that reveals their analysis assuming the opposite to be a false comparison.

Finally, the IS and DSR omit the District's own findings indicating that the refinery-wide emissions backstop now proposed as Rule 12-16 is a necessary complement to other rules that seek to reduce emissions from selected refinery sources.[2] Simply put, preventing increases in refinery-wide emissions complements the other measures by allowing them to reduce refinery emissions incrementally over time and enhancing their ability to do so. Indeed, the District Staff's projection that these other measures will reduce refinery-wide criteria pollutant emissions by approximately 15 % that is reported in the DSR[31] ***relies*** on this backstop—another fact that the IS and DSR obscure by omitting District findings.

Rule 12-16 is reasonable.

Rule 12-16 would allow each refining facility to emit up to 107 % of its actual maximum annual emissions over the most recent five-year period when its emissions were reported. Reported production by Bay Area refineries reached 97.7 % of their maximum crude capacity during this period,[32] they produced more gasoline and diesel than needed here and exported significant amounts of these fuels to foreign countries in this period,[33] and other adopted measures are expected to reduce emissions from these refineries.[31] Thus, Rule 12-16 itself would not be expected to require any change in refinery equipment, operation, workforce, production rate, or fuel supply. But despite these facts, and failing to disclose many of them, the IS and DSR paint this measure as unreasonably risky.

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[31] DSR at 9 (recently adopted measures projected to cut refinery-wide criteria emissions by 15%).

[32] The California Energy Commission reports gross crude oil receipts for processing by the five Bay Area refineries of 292.347 million barrels in 2014 and 285.412 MM b in 2015 (Per. comm., G. Schremp, CEC to G. Karras, CBE, 3 Aug 2016: forwarded to BAAQMD on 8 Sep 2016); the U.S. Energy Information Administration (a source the DSR relies upon) reports total operable capacity of atmospheric crude distillation units (b/cd) at these five refineries was 299.253 MM b in 2014. (EIA Refinery Capacity Report as of 1 Jan 2015.) Their operable crude utilization rate, defined by EIA as this gross input divided by this operable capacity, was thus 97.7 % in 2014.

[33] Bay Area refineries exported an average of 74,500 b/d of gasoline and diesel in 2013 (EIA data reported to BAAQMD by CBE on 25 Apr 2016) and produced these fuels at total rates averaging 611,880 b/d in 2014 and 2015 (CEC data reported to BAAQMD on 25 Apr and 19 Oct 2016), suggesting they currently export roughly 12 % of their combined gasoline and diesel production. Excess Bay Area refinery production accounted for 96 % of all gasoline exports from California refineries during the first 8 months of 2016 (CEC data reported to BAAQMD on 19 Oct 2016).

The DSR states that Bay Area-specific refinery production data are not available, that Rule 12-16 "may constrain" the domestic fuel supply market, and that this constraint would have worsened a "dramatic" gas price spike during the Torrance refinery outage in 2015. (DSR at 22, 23.) All of these statements appear inaccurate and misleading. The District had these specific data.[32–33] These data show that Rule 12-16 would allow Bay Area refineries to process ***more*** crude than they processed during the 2015 outage,[32] use ***more*** of their production capacity than they can reliably use for long periods,[34] and collectively produce roughly 12 % ***more*** gasoline and diesel than the domestic fuel market demands from them.[33] Instead of falsely blaming gas price spikes on air quality rules, the IS and DSR should have evaluated the local and global emission impacts from this excess refinery production for export—impacts Rule 12-16 would help to curb.[4]

Even though Rule 12-16 allows emissions at current rates, the IS and DSR also link it to "potentially significant" environmental impacts from the side effects of new equipment that they say it could require to reduce criteria pollutant emissions.[35] They do not explain why their analysis ignores the District staff's own finding that ***other*** recently adopted measures are projected to cut refinery-wide criteria pollutant emissions by ≈ 15 %,[31] or how Rule 12-16 itself would require new equipment to reduce emissions that already would be 15–22 % below[36] its applicable emission limits.

A major switch to refining lower quality oil or to increasing production for export would have to overwhelm the already-required emission reductions before Rule 12-16's PM, NOx, or SO_2 limits might be exceeded—and these scenarios, while clearly foreseeable, would require major infrastructure projects.[18–26] Rule 12-16 would prevent severe and irreversible emission impacts in these scenarios. Further, because it would prevent increased emissions it would discourage such harmful projects and encourage projects using lower-emitting production systems, thereby encouraging the prevention of the types of emission mitigation side-effects the IS asserts. Finally, and also ignored by the IS and DSR,[4] these emission impact prevention, irreversible impact prevention, and new emission mitigation impact prevention effects are among the objectives and intended results of Rule 12-16.

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[34] Compare note 32 above (2014 Bay Area refinery capacity utilization of 97.7 %) with the DSR at 23 ("Peak refining utilization [on a weekly basis at West Coast refineries from 2010–June 2016] appears to be about 93.5 percent. Given the few times when that peak was achieved, it's unlikely to be sustained over a long period due to unplanned outages and planned maintenance.").

[35] *See* IS at 2-40 (SCR equipment assumption) and 2-46 (wet scrubbing equipment assumption).

[36] Low end of 15–22% range based on other rules' reduction; high end (22%) also includes the 7% "operating variation" included in calculation of Rule 12-16 limits (*see* § 12-16-302).

Conclusion

Rule 12-16 is reasonable, effective, a necessary complement to other air quality and climate protection measures, and urgently needed. It would close a gaping loophole that has left facility-wide emissions from oil refineries unlimited. It is needed to prevent the biggest industrial emitters of the most harmful air pollutants known from causing severe and irreversible climate and health impacts by locking in bottom-of-the-barrel oil infrastructure that could increase those emissions for another generation.

However, the Initial Study and Draft Staff Report released by District staff management assert conclusions regarding the need for Rule 12-16, its effectiveness, and your authority to adopt it that are proven false by factual information they fail to disclose or analyze. Worse, as we document herein, this crucial information that is omitted and ignored includes facts the District already knew, and even its own previous findings.

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Respectfully,

Andrés Soto and Greg Karras
Communities for a Better Environment (CBE)

Luis Amezcua
Sierra Club San Francisco Bay Chapter

Richard Gray
350 Bay Area

Ratha Lai
Asian Pacific Environmental Network (APEN)

Janet Scoll Johnson
Richmond Progressive Alliance (RPA)

continued

Steve Nadel, Charles Davidson, and Earl Koteen
Sunflower Alliance

Nancy Reiser
Crockett-Rodeo United to Defend the Environment (C.R.U.D.E.)

Katherine Black
Benicians for a Safe and Healthy Community

Janet PyGeorge
Rodeo Citizens Association (RCA)

Rev. Will McGarvey
Interfaith Climate Action Network of Contra Costa County

Denny Larson
Community Science Institute—CSI for Health and Justice!

Bradley Angel
Greenaction for Health and Environmental Justice

California Nurses Association (CNA)

Copy: Clifford Rechtschaffen, Office of Governor Edmund G. Brown
Richard Corey, California Air Resources Board
Refinery Action Collaborative of Northern California
Interested organizations and individuals

California Council for Environmental and Economic Balance
101 Mission Street, Suite 1440, San Francisco, California 94105
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December 2, 2016

Mr. Victor Douglas
BAAQMD
375 Beale Street, Suite 600
San Francisco, CA 94105

RE: Proposed Regulation 11, Rule 18 and Regulation 12, Rule 16

Dear Mr. Douglas,

We appreciate the opportunity to submit these comments on behalf of the California Council for Environmental and Economic Balance. CCEEB is a non-profit and non-partisan coalition of business, labor, and public leaders that advances strategies for a sound economy and a healthy environment. We have many members that operate facilities in the air basin and are subject to proposed Regulation 11, Rule 18 (Reg. 11-18). CCEEB has been active in this rulemaking since July, and we thank staff for expanding its outreach to stakeholders over the past couple of months. Reg. 11-18 is a significant new rule and will likely have significant compliance costs for many businesses. We offer a number of initial questions and suggestions on Reg. 11-18 below, and look forward to working with staff to further refine this rule.

In terms of proposed Regulation 12, Rule 16 (Reg. 12-16), CCEEB must repeat our concerns as stated in our letter to you from September 9, 2016, and we include by reference those comments here. Additionally, CCEEB agrees with analysis in the draft staff report that calls into question the District's authority to implement Reg. 12-16. We include in our comments here more details about our reasoning for this position.

Comments on Regulation 11, Rule 18

<u>Clarify Authority in Staff Report</u>

In meetings with stakeholders, staff has explained that Reg. 11-18 is not based on District authority under AB 2588, the Air Toxics "Hot Spots" Information and Assessment Act (1987), and as such, it differs from the statewide program codified in Sections 44300-44394 of the California Health and Safety Code. CCEEB asks that staff clarify its authority for Reg. 11-18 and identify the relevant state and federal codes, particularly those sections related to establishing Best Available Retrofit Control Technology for Toxics (TBARCT). We note that other air districts in California continue to regulate existing facilities under AB 2588, based on regularly updated emission inventories and health risk assessments (HRAs), in addition to review of new and modified sources under New Source Review.[1]

Provide Opportunity for Facilities to Conduct HRAs and Enhance Review Process

The October 14, 2016 Initial Study for Reg. 11-18 indicates the District will use independent contractors to conduct HRAs due to a lack of staff resources necessary to carry out this work. CCEEB recommends that Reg. 11-18 be revised to provide an opportunity for facility operators to voluntarily conduct and submit HRAs for the purposes of complying with the rule. Any facility-submitted HRA would follow District HRA guidelines and be subject to review and approval by District staff. The advantages of facility-submitted HRAs are efficiency and accuracy; facility operators will have detailed knowledge of and data on equipment, operations, emissions monitoring and modeling, inventory reporting, emission factors, proximity of workers and nearby residents ("receptors"), and local meteorology. Such facility-specific information would help facilitate the efficient and accurate preparation of HRAs. Should staff find it necessary to reject a submitted HRA, the District could require the facility to resubmit the HRA with amendments.

Allowing facilities to conduct and submit HRAs is a standard practice. For example, Regulation 2-5-401 requires a permit applicant to submit an HRA, following the District's HRA guidelines. Similarly, under AB 2588, the state Legislature requires facilities to submit HRAs (H.&S.C. Section 44360(b)(1)). CCEEB believes that facility-submitted HRAs would in no way diminish the stringency or transparency of Reg. 11-18; rather, it would increase transparency, streamline the review process, and focus staff resources on reviewing HRAs or preparing HRAs for only those that choose to have the District do this analysis. Additionally, the BAAQMD could submit HRAs to the Office of Environmental Health Hazard Assessment (OEHHA) for review and comment, as is done under AB 2588 and H.&S.C. Section 44361.

Need Process to Reconcile Potential Disputes over Risk Reduction Plan Disapprovals

CCEEB wishes to work with staff to develop a dispute resolution process in cases when a facility needs to challenge or question a final action to disapprove a risk reduction plan. While we hope such instances would be rare in occurrence, CCEEB believes a dispute resolution mechanism is warranted given the unclear process to be used to make TBARCT determinations and the current lack of guidance available on what would be considered TBARCT for new and modified sources.

Explain Interaction of New Source Review Rules with Reg. 11-18

The District's New Source Review rules (Regs. 2-1, 2-2 and 2-5) require new or modified sources to apply for a project permit. Under Regulation 2, Rule 5 (Reg. 2-5), any source

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[1] From the October 2016 Draft Staff Report (page 28): "The Air District adopted its Air Toxics New Source Review program at about the same time it started its activities to assess existing facilities under the Hot Spots Act. As a result, sources that existed in the late 1980's have been reviewed under the Hot Sports program and sources that were constructed or modified after the late 1980s have been reviewed under the Toxics NSR program."

with an estimated risk greater than 1-in-a-million and/or a chronic hazard index greater than 2.0 would be required to apply Best Available Control Technology for Toxics (TBACT).

Proposed Reg. 11-18 would require an existing facility to reduce risks below 10-in-a-million. To do so, a facility would likely need to apply for an NSR permit for a new or modified source, which in turn could trigger TBACT requirements. If a facility could not reduce below the Reg. 11-18 risk action levels, it would be required to install Best Available Retrofit Control Technology for Toxics (TBARCT) on all "significant sources," which, by definition, would also trigger TBACT under Reg. 2-5. We ask staff to explain how this process would work in practice, and to clarify whether a significant source would need to apply TBARCT, TBACT, or both.

Establish a Technical Working Group and Define TBARCT as Part of Rulemaking

CCEEB reiterates our request that the District establish a technical working group to help advise staff in developing a process to make TBARCT determinations and in defining TBARCT for specific sources. We believe such an effort is being planned, and thank staff for considering our past comments.

We also repeat our request that TBARCT be defined as part of the Reg. 11-18 rulemaking, as we see this as necessary for preparing the socioeconomic analysis as required by state H.&S.C. Section 40728.5, including analyses to determine the range of probable costs, the impact of the rule on regional employment and the economy, the availability of cost-effective alternatives, and the emission or risk reduction potential of the rule. Moreover, understanding what would be considered TBARCT helps inform regulated businesses as to what would be required under Reg. 11-18 and what compliance options would available to them, which in turn could prompt useful public participation and comments on the draft rule. This is especially important given that Reg. 11-18 is remarkable both in terms of the total number of facilities affected as well as the many different facility types that will become subject to the rule.

In addition, we note that the current unavailability of TBARCT guidelines discourages early actions to reduce risk. Facilities that take early action and install risk reduction technologies voluntarily in attempt to decrease risk below the notification thresholds could be burdened with additional cost if these reductions turn out later not to meet the TBARCT standard.

More generally, CCEEB believes that the District should allow adequate time to develop sound, scientifically based rules, and to conduct a fair and transparent public participation process. Conversely, we are concerned if rules are rushed to hearings before staff has fully developed implementation details and compliance pathways.

Modify Reference to MACT in Definition of TBARCT

Reg. 11-18 defines TBARCT as the most stringent of certain retrofit emission controls, including, "[t]he most stringent emission control for a source type or category specified as

MACT by U.S. EPA…" Reg. 11-18-204.4. "MACT" is simply defined as "[a]n emission standard promulgated by U.S. EPA pursuant to Section 112(d) of the Clean Air Act." [Reg. 11-18-212.] However, for many source categories that could be subject to Reg. 11-18, EPA has promulgated both new source and existing source MACT standards under Section 112(d) of the Clean Air Act. Clearly, the District's intent is that TBARCT can be no less stringent than an existing source MACT standard. However, TBARCT cannot and should not be defined in reference to new source MACT standards, which may be unachievable, infeasible, or prohibitively costly for existing sources subject to TBACT. CCEEB would ask that the District revise the definition to clarify that, for existing sources that have not previously been subject to the new source MACT standard promulgated by EPA for that source type or category, TBARCT shall be no less stringent than any relevant existing source MACT standard.

Provide Public Information Templates as Part of Staff Report

The draft staff report indicates that the District will provide facility information to the public via email notices, social media, the District's website, opt-in mailings, and community meetings. However, the draft report does not describe how these communications will be managed or what content will be provided. Risk communication is an important but too often contentious subject; context is key.

Facilities have a direct and significant interest in how their operations are viewed by their neighbors, and many have ongoing community outreach and public relations efforts. The District should be sensitive to this dynamic, and avoid risk communication that is confusing or unduly politicizes toxic risks. It is also critical that the District put risks from air toxics into context so that it is readily and clearly understood.

CCEEB requests that staff provide templates for how toxic risks from facilities will be described and communicated, such as through an appendix to the staff report. We also request that staff include in this simple background information, including but not limited to the degree to which risks from air toxics have been steadily decreasing in the air basin, the proportionate contribution of different source types (mobile, stationary, and area) to ambient risks, as well as an explanation of the difference between background or ambient risk and risk from a single, local source.

Finally, CCEEB recommends that facility information be limited to only those facilities above risk action levels, and that only final, District-approved documents be released. This helps interested public focus on facilities with the highest risks, rather than having to sort through documents for a 1000+ facilities, many of which may not pose real public health concerns. At a minimum, we ask staff to remove reference to draft HRAs since the preparation, review, and approval of HRAs follow strict, objective scientific guidelines and are not meant to be changeable or subjective based on public comments.

How Would APCO Shorten Risk Reduction Plan Time Periods?

Reg. 11-18-402.2 states that the APCO may shorten the three-year time period allowed to implement risk reduction plans if (a) the APCO finds that it is "technically feasible and economically practicable," or (b) the facility is in a CARE designated area and exceeds a significant risk threshold (i.e., either a cancer risk threshold of 1-in-a-million, a chronic HI of 0.20, or a acute HI of 0.20). CCEEB asks staff to clarify how the APCO would determine what is "technically feasible and economically practicable," and how or on what basis the APCO would determine the appropriate time period.

For facilities in CARE communities, how short would the time period be, and would it be the same for all facilities in those areas? Would the APCO use discretion, shortening the time period for some facilities but not others, or in some communities but not others, and if so, what criteria would these decisions be based on? What if a facility in a CARE community could not reduce risks in the shortened time period? Would an extension be needed? We note that CARE designations closely follow transportation corridors, congestion, and emissions of air toxics and other pollutants from mobile sources, particularly diesel particulate matter. In many cases, the incremental contribution of a stationary source facility could be de minimis.

What Would Prompt an Updated Risk Reduction Plan?

Reg. 11-18-405 gives the APCO the authority to require the facility to update its risk reduction plan "if information becomes available…regarding the health risks posed by a facility or emissions reduction technologies that may be used by a facility that would significantly impact health risks…" We ask staff to clarify this section in the rule and in the staff report. Specifically, we ask staff to explain what new information it is anticipating in regards to health risks. For example, is the concern that actual health risks are above what was estimated in the emissions inventory and HRA? And if so, what level of an increase would prompt the APCO to act? What happens if the increase was due to an increase in production but still within permit limits and the facility was on track to meet all Reg. 11-18 requirements?

In terms of "emission reduction technologies," does this mean that the APCO could force a facility to change its plan whenever a new control technology or risk reduction measure becomes available? What if risk reduction projects were already underway? What time period would be given to the facility, or would the clock restart after the updated plan was approved? Would the District determine economic impacts based just on the updated plan, or would it calculate total costs for the initial approved plan plus added costs for updating the plan? Could the APCO apply Reg. 11-18-405 multiple times, so that a facility was caught continuously updating a plan (and investing in risk reduction projects) whenever new technologies became available? What if the facility demonstrates that it will get below the risk reduction threshold in the time provided – could it then dispute the requirement to update its plan or seek a variance from the Hearing Board? CCEEB has serious concerns with this language as written and would like to better understand what is intended.

CEQA Analysis Should Include the Original 25-in-a-million Alternative

In July, staff presented a proposal for Board approval that set a first phase of Reg. 11-18 with a risk reduction threshold of 25-in-a-million. While we recognize that staff has revised its proposal and is no longer recommending the phased approach in the draft rule, we ask again that the 25-in-a-million option be included in the CEQA analysis as an alternative and that it be used to compare compliance costs and incremental health benefits, and to establish reasonable cost ranges in the socioeconomic report.

Comments on Regulation 12, Rule 16

District Staff Are Correct that Reg. 12-16 Would Be Inconsistent with District's Authority

The draft staff report provides staff's analysis that the fixed numeric caps on refinery emissions proposed by draft Regulation 12, Rule 16 are inconsistent with the requirements of the federal Clean Air Act (CAA) and California law. [*Draft Staff Report, Draft Regulation 12, Rule 16: Petroleum Refining Facility-Wide Emissions Limits and Draft Regulation 11, Rule 18: Reduction of Risks from Air Toxic Emissions at Existing Facilities*, Oct. 2016 ("draft staff report"), pages 17-20.]

In particular, staff notes that both the CAA and California law require permitting programs that allow for criteria pollutant emissions to increase at one location so long as those emissions are offset by reductions elsewhere. *Id*. at 17. CCEEB agrees with staff's analysis of this inconsistency. Additionally, by essentially imposing a construction moratorium upon refinery expansion when none is authorized or warranted under the CAA, Reg. 12-16 would stand as an obstacle to the accomplishment and execution of the full purposes of the objectives of Congress in enacting the CAA and designing a program for controlling emissions from new and modified sources. *See Hines v. Davidowitz*, 312 U.S. 52, 67 (1941).

As the draft staff report indicates, proposed Reg. 12-16 would address pollutants of primarily regional or global concern by limiting those pollutants from one particular sector, even though the concentrations of criteria pollutants are roughly the same in refinery communities as in other urbanized areas of the region. *See* draft staff report at page 18. California law imposes several requirements for new rules, including that the air district demonstrate the rule's "necessity" (Cal. Health & Saf. Code § 40727(b)(1)). The District would be challenged to demonstrate the necessity of a rule targeting an individual sector and its emissions, when the impacts from that sector are, as staff acknowledges, indistinguishable on a regional scale from those of other sectors. In light of the regional and global impacts associated with the emissions targeted by Reg. 12-16, CCEEB also agrees that the theoretical co-benefits associated with regulating criteria and greenhouse gas (GHG) emissions, so as to limit localized refinery communities' exposure to pollution (*see* draft staff report at page 20), cannot provide legal justification for such a rule.

CCEEB also agrees with staff that the Reg. 12-16 caps on GHG emissions would fail to satisfy state law because facility-specific caps are fundamentally inconsistent with the Air Resources Board Cap-and-Trade Program. *See* draft staff report at page 19. The State's Cap-and-Trade Program has been carefully designed to achieve the maximum technologically feasible and cost-effective reductions in GHG emissions through use of market forces, while also minimizing emissions leakage. *See* Cal. Health & Saf. Code §§ 38562(a), (b)(8). Placing caps on facilities in the Bay Area would frustrate the efficiency goals of the Cap-and-Trade Program, as recognized by District staff. *See* draft staff report at page 19 ("There is a fundamental inconsistency between a 'cap and trade' program that by its nature contemplates changeable caps versus one that fixes caps at one level, in that the latter has the potential to frustrate the efficiency goals of the former."). It would also potentially result in emissions leakage to sources elsewhere in the state or out-of-state, thus achieving no net reduction in GHG emissions. Even assuming the District were legislatively delegated the authority to promulgate such a rule, doing so would run afoul of the requirement that district rules must be consistent and in harmony with existing State law (*see id*. § 40727(b)(4)), and not be arbitrary, capricious, or without a reasonable or rational basis. *See S. Cal. Gas Co. v. S. Coast Air Quality Mgmt. Dist*., 200 Cal. App. 4th 251, 267-68 (2011).

CCEEB thanks staff for considering our comments on proposed Regulations 11-18 and 12-16 and we look forward to seeing your response. We also appreciate recent staff efforts to notify and engage potentially affected industry on Reg. 11-18, and we continue to support a full public participation process for rule development. CCEEB is committed to working with the staff and the Board of the District in refining Reg. 11-18 and addressing the questions and concerns we outline in this letter. Please contact me or Janet Whittick of CCEEB at any time should you have questions or wish to discuss our comments further. I can be reached at (415) 512-7890 ext. 115 or billq@cceeb.org; Ms. Whittick is available at ext. 111 or janetw@cceeb.org.

Sincerely,

Bill Quinn

Bill Quinn
CCEEB Chief Operating Officer and Bay Area Partnership Project Manager

cc: Mr. Jaime Williams, BAAQMD
Mr. Eric Stevenson, BAAQMD
Mr. Gerald D. Secundy, BAAQMD
Ms. Janet Whittick, CCEEB

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December 2, 2016

ESDR-364-16
05-C-03-G

VIA Email

Mr. Victor Douglas (VDouglas@baaqmd.gov)
Manager, Rule Development Section
Bay Area Air Quality Management District
375 Beale Street, Suite 600
San Francisco, CA 94105

RE: Phillips 66 Company: Comments on BAAQMD's Notice of Preparation for DEIR Draft Regulation 12, Rule 16 and Draft Regulation 11, Rule 18

Mr. Douglas:

Phillips 66 Company (Phillips 66) is providing comments in this letter related to the Notice of Preparation (NOP) for two new Bay Area Air Quality Management District (District) rules currently being developed – Regulation 12, Rule 16: Petroleum Refining Facility-Wide Emission Limits (Reg. 12-16) and Regulation 11, Rule 18: Reduction of Risk from Air Toxic Emissions at Existing Facilities (Reg. 11-18).

In addition, Phillips 66 supports and adopts the comments of the Western States Petroleum Association (WSPA) and the California Council for Environmental and Economic Balance (CCEEB) on the above-referenced Regulations submitted on December 2, 2016.

Due to the complicated nature of the proposed Regulations referenced above, Phillips 66 requests that additional time be allowed to provide comments and work with District staff.

Regulation 12, Rule 16

The California Environmental Quality Act ("CEQA") requires that the District's Environmental Impact Report for the project consider the entire project. As you are aware, the CEQA Guidelines define a "project" to be the whole of an action, which in this case includes all regulations associated with Board Resolution 2014-07 targeting emissions reductions from refineries. .

Proposed Regulation 12, Rule 16 will likely curtail refinery production below levels already achievable in practice and currently permitted, which infringes on Phillips 66's vested rights. The proposed rule severely inhibits (or may altogether prevent) the ability of Bay Area refineries to build new equipment or process units that may be required to meet future Federal and/or California Air Resource Board (CARB) fuel standards or to respond to increases in demand. This may make one or more refineries obsolete and potentially force their closure.

The proposed rule is not necessary, and, in fact, District Staff itself recognizes the difficulty that the Board will have in making the finding of "necessity" required by California Health and Safety Code section 40727(a): "[a]t the very least, it would be difficult to legally justify the necessity for the [proposed rule]…" (*BAAQMD Draft Staff Report, Draft Regulation 12, Rule 16: Petroleum Refining Facility-Wide Emissions Limits* (October 2016), p. 17). Phillips 66 also believes that the Board will not be able to make the required finding of "consistency," which is a view shared by District Staff in the *BAAQMD Draft Staff Report* ("Staff is concerned that a fixed numeric cap on refinery emissions may not be consistent with requirements of the Federal Clean Air Act (CAA) and the California Health and Safety Code (H&SC)"). Further, the proposed rule is arbitrary and capricious in that it imposes a specific regulatory regime on one particular sector of the regulated community – *i.e.*, refining – without any support whatsoever that such disparate treatment is either necessary or appropriate. Again, this view is echoed by District Staff at pages 17 and 18 of the *BAAQMD Draft Staff Report* ("Staff is also concerned that there is no support for imposing a particular regulatory approach on one sector of the regulated community without factual support for such selective treatment").

Adoption of the proposed Regulation 12, Rule 16 would be beyond the Board's legal authority. District Staff has arrived at this same conclusion (*BAAQMD Draft Staff Report*, pages 3, 19, and 20). If the Board adopted this proposed rule, it would be a transparent attempt to utilize legislative authority that the Board does not rightfully have, which will have been hijacked by the Board solely to impose the Board's own purported policy choices on a discreet sector of the economy and regulated community.

The District needs to evaluate the environmental, socioeconomic and other factors associated with restricting refinery operations. The potential to affect fuel supply in the Bay Area must be thoroughly evaluated. For instance, the District must evaluate the GHG impacts of importing gasoline from outside the State or from foreign countries should a fuel shortage be caused or exacerbated by proposed Reg 12-16.

Regulation 11, Rule 18

The District must provide a thorough scientific justification for why a risk threshold of 10 in a million (10/M) was arbitrarily chosen. The District's own Community Air Risk Evaluation (CARE) study estimated that average background air quality in the Bay Area is roughly 50 times greater than the proposed risk threshold of 10/M. The District must determine if the Rule is implemented whether or not all reducing risk from all facilities to below 10/M would even have a significant effect on the overall risk from background air quality.

District staff had previously reported a 25/M risk threshold to the Board, but this threshold has been removed and replaced with the 10/M threshold without any explanation. Phillips 66 requests that District staff provide an analysis of the number of facilities with a risk greater than 25/M compared to the estimate of over 1,100 facilities with a risk of greater than 10/M reported in the *BAAQMD Draft Staff Report*. This information must be presented as part of the project alternatives and the EIR and staff report must analyze any additional benefits and costs associated with reducing the risk threshold from 25/M to 10/M. The District must show that these thresholds are necessary and cost effective.

The *BAAQMD Draft Staff Report* explains that the District will use the annual toxic emissions inventories reported to the District to conduct site-specific HRAs for sources that emit toxic compounds. Section 11-18-403.3, in turn, requires the Risk Reduction Plan to include a source characterization that includes "summary data from the applicable APCO-approved air toxic emission inventory." However, proposed Rule 11-18 provides no further clarity with respect to the emissions inventory component. To help ensure consistency in emission inventory and health risk assessment methods across facilities, Phillips 66 requests that Rule 11-18 clarify that the emission inventory is based on actual emissions.

The BAAQMD should provide guidance and a more thorough review of proposed Regulation 11, Rule 18 (Reg 11-18) in relation to the changes proposed to Regulation 2-5 and the recent changes to Regulation 2 Rules 1 and 2 (Regs 2-1& 2). These regulations will all potentially have effects on the other regulations and should be thoroughly reviewed to determine if there are any inconsistencies or other potential issues.

- For instance, potential risk reductions required by Reg 11-18 may require permits and review via Regs 2-1 & 2 and Reg 2-5. What are the effects if Reg 2-5 required TBACT on a project being conducted for Reg 11-18 compliance, when currently Reg 11-18 only requires TBARCT?
- What if a project is required by proposed Reg 11-18 risk reduction requirements but is not issued a permit pursuant to proposed Reg 2-5 because the potential to emit only for the project is included in the Reg 2-5 analysis? Is the facility then out of compliance with Reg 11-18?

TBARCT should be better defined as part of the Reg 11-18 rulemaking. Defining TBARCT is necessary to prepare the socioeconomic analysis and determine the range of probable costs, define the impact of the rule on regional employment and economy, determine the availability of cost-effective alternatives and quantify the emission or risk reduction potential of the rule. Moreover, this would help inform regulated businesses about what would be required and what compliance options are available, which in turn could prompt useful public participation and comments on the draft rule. The current definition of TBARCT in 11-18-204 does not adequately consider cost-effectiveness, as it requires installation of the most stringent retrofit emissions controls available.

As Sections 11-18-301 and 11-18-403.6 are currently written, they could be interpreted to mean that all sources of risk anywhere in the facility must be below the significant risk thresholds or have TBARCT. Based on conversations with District staff, Phillips 66 believes the intent of the Reg was to control only those sources of risk that affect the receptors with impacts above risk action levels in Section 11-18-214, not all sources at the facility. Accordingly, Philips 66 suggests the following edits to clarify the proposed text in Sections 11-18-301.2 and 11-18-403.6.1:

- 11-18-301.2 "Demonstrate to the satisfaction of the APCO that all facility sources of risk ~~at the facility~~ that impact any receptor where the health risk from the facility exceeds one or more of the risk action levels in Section 11-18-214 either:
  - 2.1 Are controlled with current TBARCT, or
  - 2.2 Do not pose a health risk that equals or exceeds of one or more of the significant risk thresholds set forth in Section 11-18-217."

- 11-18-403.6.1 "A demonstration that all facility sources of risk ~~at the facility~~ that impact any receptor where the health risk from the facility exceeds one or more of the risk action levels in Section 11-18-214 are either controlled with TBARCT, or do not pose a health risk in excess of the significant risk threshold, or"

Lastly, the District's choice of facility prioritization for implementation of the proposed Rule appears arbitrary. Multiple times in the *BAAQMD Draft Staff Report*, CARE communities are noted as the areas with the highest risk; however, the District did not consider the CARE communities when determining the prioritization. Further, diesel PM is the largest contributor to Bay Area risk as illustrated in Figure 5 of the *BAAQMD Draft Staff Report*, however, the primary stationary source of diesel PM emissions, diesel engines, are not proposed to be addressed by the rule until the third implementation phase, and reductions from these sources won't be implemented until 2024 at the earliest. The District should prioritize implementation of facilities that are located in CARE communities because they are the areas with the highest overall risk.

If you have any questions regarding these comments, please contact me at (510) 245-5825.

Sincerely,

Don Bristol
Environmental Superintendent

Attachment

cc: Eric Stevenson, BAAQMD (via e-mail: EStevenson@baaqmd.gov)
Greg Nudd, BAAQMD (via e-mail: GNudd@baaqmd.gov)

Western States Petroleum Association
Credible Solutions • Responsive Service • Since 1907

Catherine Reheis-Boyd
President

December 4, 2016

Mr. Victor Douglas via email (vdouglas@baaqmd.gov)
Principal Air Quality Specialist
Bay Area Air Quality Management District (BAAQMD)
939 Ellis Street
San Francisco, CA 94109

Re: WSPA Comments on Draft Proposed Rules for Regulation 11, Rule 18 and Regulation 12, Rule 16

Dear Mr. Douglas:

The Western States Petroleum Association (WSPA) is a non-profit trade association representing twenty-six companies that explore for, produce, refine, transport and market petroleum, petroleum products, natural gas and other energy supplies in California, Arizona, Nevada, Oregon, and Washington. Our members in the Bay Area have operations and facilities regulated by the Bay Area Air Quality Management District (District).

WSPA has significant concerns with regard to the District's proposed Regulation 11, Rule 18 (Rule 11-18) and Regulation 12, Rule 16 (Rule 12-16), as described more fully in Attachments A and B. In addition, it is unclear whether the District intends to develop and propose both draft Rules to the Board for consideration, such that both Rules could presumably be adopted by the District, or whether the District intends to propose Rules 11-18 and Rules 12-16 as alternative suggestions for reducing emissions from petroleum refineries, such that only one of the two Rules would be adopted. To the extent that both rules may be adopted by the Board, the District needs to assess the impacts, feasibility, and costs of complying with both sets of requirements before proposing the draft Rules to the Board for adoption. In addition, WSPA requests that more time be allowed to provide comments on these proposals due to their complex nature and wide scope.

WSPA appreciates the BAAQMD's consideration of our comments and we look forward to your responses. If you have any questions, please contact me at this office, or Bob Brown of my staff at (925) 708-8679 or email bbrown@wspa.org.

Sincerely,

Catherine H Reheis-Boyd

Attachments:

Attachment A: WSPA Comments on Proposed Regulation 11, Rule 18
Attachment B: WSPA Comments on Proposed Regulation 12, Rule 16

Attachment A
WSPA Comments on Proposed Regulation 11, Rule 18

CALIFORNIA HEALTH & SAFETY CODE REQUIREMENTS

The California Health & Safety Code requires the District to make six statutory findings before amending a rule: necessity; authority; clarity; consistency; nonduplication; and reference Cal. Health & Safety Code § 40727. As Rule 11-18 is currently drafted and structured, the District will not be able to meet these statutory requirements, particularly with respect to the elements of necessity, consistency, and clarity.

The Stringency of Draft Rule 11-18 is Not Necessary

Draft Rule 11-18 will require all facilities, including non-refinery entities, with a calculated risk level of 10 per million (10/M) to develop a Risk Reduction Plan to implement controls that will reduce the facility's risk level. The stated purpose of draft Rule 11-18 is to "ensure that facilities that emit toxic air contaminants do not pose an unacceptable health risk to nearby residents, workers, or students." § 11-18-101. However, the District has not explained why a risk of 10/M is the appropriate threshold for acceptable versus unacceptable risk. The District recognizes that Rule 11-18 is "more stringent than most" other air programs being implemented in California to address toxic emissions from existing facilities, but fails to explain the basis for regulating so much more stringently.

The District must provide a more reasoned and scientific explanation for its proposal to decrease the risk level of 10/M from the current risk level of 100/M for existing facilities. While Cal. Health & Safety Code §§ 39002 and 39013 provide the District with authority to control air pollution from stationary sources, the District must nevertheless balance that authority with the necessity of a rule. The District's Staff Report states that the risk action levels in § 11-18-214, which are based on the OEHHA's 2015 Health Risk Guidelines, "reflect the most health protective levels achievable and correspond to the health risk levels that the Air District uses for the existing 'Hot Spots' program." At the outset, the OEHHA itself has identified the risk levels proposed in the 2015 Health Risk Assessments Guidelines as conservatively *high* estimates of risk (because they take the most sensitive populations into consideration).[1]

More to the point, this reasoning does not explain why such conservative risk thresholds are necessary in light of the Bay Area's air quality, which the District itself has acknowledged has improved dramatically. As the Staff Report notes, over the last few decades TAC emissions from stationary sources in the Bay Area have decreased by 87%, and the average Bay Area risk from exposure to TACs has been reduced by 83%. Staff Report, at 25-26. Furthermore, these figures do not account for the additional reductions that will occur as WSPA's members implement the additional controls imposed over the past year through the District's Refinery Strategy, which the District has calculated will further reduce refinery emissions by 15%.

The District proposes to calculate a facility's health risk in accordance with OEHHA's 2015 Health Risk Assessment (HRA) Guidelines, which lower the risk screen trigger levels for carcinogenic TACs as compared to OEHHA's prior guidelines, and thereby result in higher risk calculations for the same level

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[1] OEHHA's Guidance Manual for Preparation of HRAs identifies that "...there is a great deal of uncertainty associated with the process of risk assessment....The assumptions used in these guidelines are designed to err on the side of health protection in order to avoid underestimation of risk to the public....Risk estimates generated by an HRA should not be interpreted as the expected rates of disease in the exposed population but rather as estimate of potential for disease, based on current knowledge and a number of assumptions...."

of TAC emissions from regulated sources. At the same time, as discussed above, actual health risks associated with TAC emissions are lower than they have ever been within the District. Staff Report, at 25-26. This significant progress calls for a balanced approach to regulation. Indeed, other air districts with worse air quality (e.g., more criteria pollutants in non-attainment), including the South Coast and San Joaquin Valley Air Districts, have determined that a higher risk threshold is protective of human health given the recent changes in the OEHHA guidelines. The District should avoid inciting unnecessary confusion and fear among the public based on dramatically overstated risks or require installation of unnecessary controls for operations that do not pose actual significant risks to the public,, or if the added controls do not make a perceivable improvement in the overall risk of the area around the source. Analysis should also be completed on the effects of all the regulated facilities dropping to a risk less than <10/M to determine if these estimated reductions at stationary sources make any perceivable difference to the receptors.

WSPA believes that it is especially appropriate to reconsider the risk threshold in § 11-18-214.1, because, unlike the hazard indices which are based upon conservative estimates of the level of air pollution concentrations that might cause a health effect, the risk limit does not have a scientific basis. Past risk thresholds (including the District's existing 100/M threshold under AB2588) have been based on what regulators believed was possible for facilities to achieve. Along the same lines, the District claims that the 10/M level was chosen because it reflects "the most health protective levels achievable" (Staff Report page 30). However, the Staff Report does not provide any data or analysis to support this claim. Rather, the District here seems to simply assume that a 10/M will be "achievable" by existing facilities.

The District assumes too much. The achievability of reducing an existing facility's TAC emissions to below the 10/M risk level will depend on several factors, such as the District's definition of "source," its emission calculation methods, its dispersion models, its risk calculation models, and changes in acute and chronic reference exposure levels. If the District chooses to adopt hazard indices and risk thresholds that were derived based on what levels are "achievable," it must provide a thorough assessment documenting that those levels are in fact scientifically, technologically, and economically achievable under the proposed rule as written.

WSPA suggests that the District consider a risk reduction threshold for risk of 25/M. This value was reported to the Board initially on July 20, 2016 and later removed from consideration without any written analysis or justification. The District should further assess the feasibility and cost-effectiveness of a 25/M threshold, along with the incremental costs and benefits of going from 25/M to 10/M.

Draft Rule 11-18 is Not Consistent with the Proposed Amendments to Rule 2-5

WSPA requests revisions to Rule 11-18 for consistency with the proposed amendments to Regulation 2, Rule 5 (Rule 2-5). Rule 2-5 exempts new and modified internal combustion engines smaller than 50 hp and treats retail gasoline facilities differently; however these same sources either by themselves or in conjunction with other sources at the same facility could trigger the need for a Risk Reduction Plan under Rule 11-18. WSPA suggests that the District consider exempting sources from Rule 11-18 that were already subject to or listed as exempt from Rule 2-5. WSPA also requests revision to Rule 11-18 to allow similar treatment of gasoline dispensing facilities as under the proposed amendments to Rule 2-5.

In addition, draft Rule 11-18 is unlikely to provide any emissions reductions for certain existing source types that are already implementing analogous TBARCT controls for toxics. These source types would include retail gasoline dispensing facilities subject to BAAQMD Rule 8-7, and gasoline bulk terminals subject to BAAQMD Rules 8-5, 8-18, and 8-33. WSPA therefore suggests that the District consider exempting any facilities from draft Rule 11-18 that are already subject to requirements that reflect TBARCT.

Draft Rule 11-18 is Not Sufficiently Clear

Several of the provisions of proposed Rule 11-18 are not sufficiently clear to be understood, as required by Cal. Health & Safety Code § 40727(a) and (b)(3).

Applicability. The applicability of draft Rule 11-18 depends entirely on the District's calculation of a facility's health risk. With the exception of the requirement in § 11-18-401 for facilities to submit "any information necessary to complete an HRA of the facility" at the District's request, the draft rule does not describe the procedures, or limits, to the District's determination of applicability. The Staff Report explains that the District will use emissions inventory data to screen for facilities with a priority score of ten or greater or a non-cancer priority score of one or greater, and then conduct health risk assessments (HRAs) for those facilities in accordance with the most recent versions of OEHHA's HRA Guidelines, CARB AB2588, and the CARB/CAPCOA Risk Management Guidelines. In addition, the Staff Report suggests that facilities will be consulted to validate the HRA model and site-specific factors. None of this is apparent from the language of the draft rule. WSPA therefore requests that the District incorporate provisions in proposed Rule 11-18 that address the District's responsibilities and procedures for determining rule applicability. This would include clarifying that (i) the HRAs to be prepared by the District will be done consistently with the OEHHA 2015 Health Risk Assessment Guidelines, and (ii) facilities will be provided with an opportunity to review and comment on both the inputs to and results of HRAs prior to being required to submit Risk Reduction Plans. WSPA also requests that data in Table 2-5-1 of Rule 2-5 be referenced in Rule 11-18.

In addition, WSPA requests that the draft rule incorporate an HRA review process that provides sufficient time for source testing and ambient air testing, and that a Hearing Board appeal process be added to the rule's provisions, much like with permit determinations.

Absent input from facilities, the District may incorrectly characterize facility emissions and/or health risk, which could lead to the District requiring facilities to install control equipment on sources that testing may show do not pose a health risk.

Cargo Carrier Emissions. The District should clarify that emissions from cargo carriers (e.g., ships and trains) are excluded from draft Rule 11-18. As discussed in prior WSPA comments on the District's Refinery Strategy rules, most cargo carriers are owned and operated by other companies. Attempting to require facilities to incorporate emissions from cargo carriers into nearby refinery emissions inventories will likely produce inaccurate data. Furthermore, as currently drafted, § 11-18-204 specifically exempts cargo carriers from TBARCT requirements. As a result, including cargo carrier emissions in the emissions inventories of adjacent facilities may potentially trigger HRA and TBARCT requirements for the adjacent facility. and even though those sources themselves are in fact exempt from the control requirements. If the District is concerned about diesel particulate emissions from cargo carriers, please take into consideration that CARB is in the process of writing an ATCM that will reduce diesel particulate matter from cargo carriers.

Toxic Emissions Inventories. The Staff Report explains that the District will use the annual toxic emissions inventories reported to the District to conduct site-specific HRAs for sources that emit toxic compounds. Section 11-18-403.3, in turn, requires the Risk Reduction Plan to include a source characterization that includes "*summary data from the applicable APCO-approved air toxic emission inventory.*" However, proposed Rule 11-18 provides no further clarity with respect to the emissions inventory component. To help ensure consistency in emission inventory and health risk assessment methods across facilities, WSPA requests that Rule 11-18 state explicitly that the HRA will be completed with the most recent available facility reported actual site stationary source emission inventory. WSPA requests clarification that for refineries, the emission inventories will be done consistently with the District's refinery emission inventory guidelines, and that the same methods will be used across industries where applicable, such as emergency diesel engines.

Risk Action Levels/Risk Reduction Plan. During Rule 11-18 workshops, District Staff indicated that facilities would not be required to install TBARCT on all sources if controls could be installed to reduce health risks below the risk action levels in § 11-18-214. WSPA requests clarification that the Risk Reduction Plan may explain how a facility will reduce risk below the risk action level, rather than install TBARCT on all sources above the significant risk threshold.

Significant Risk Thresholds. The significant risk thresholds in § 11-18-217 are far below the risk action levels in § 11-18-214. As a result, it is likely that a source with risk above the § 11-18-217 thresholds nevertheless may not contribute to risk at a receptor above the § 11-18-214 facility-wide action level. WSPA requests clarification that TBARCT would only be required on sources that contribute risk greater than the thresholds in § 11-18-217 at receptors having risk above the action levels in Section 11-18-214.

WSPA's understanding of the language in §§ 11-18-301.2 and 11-18-403.6.1 is that the District's intent was that "*each permitted source at the facility that contributes to the risk at any receptors where the facility wide risk is above the risk action levels, is either controlled with TBARCT or does not pose a health risk in excess of any of the significant risk thresholds.*" As the draft rule is currently written, however, sources which have risk impacts below the significance thresholds in § 11-18-217 at the receptors with facility-wide risks above the risk action levels would require some type of emission control, even if they do not meet the significant risk thresholds. WSPA requests that the District modify the language of the draft Rule to clarify that TBARCT is not required on a source if the health risk from the source remains below the significant risk thresholds.

Summary Data. WSPA suggests removing from 11-18-403.3.2 the requirement to include summary data for data from the HRA in the Risk Reduction Plan. As the HRA is to be prepared by the District, a facility would need to request the information from the District (the source of the HRA), and then submit the information back to the District in the Plan.

Risk Reduction Plan v. TBARCT. Section 11-18-403.6 has subsections that are confusing and should be clarified. Sections 11-18-403.6.1 and -403.6.2 are linked with an "or" conjunction, however subsections -403.6.2 and -403.6.3 are linked with an "and" conjunction. It is unclear whether TBARCT is required by the due date of the Risk Reduction Plan or by three years from the date of Plan submittal if health risk cannot be reduced below the risk action levels; and if the District intends the former, it is very likely not possible to install TBARCT on all sources by the date of Plan submittal. Also, it is unclear how a facility would "*develop risk reduction measures…to comply by the specified date*" in § 11-18-403.6.3 when a facility demonstrates that compliance is technically infeasible or would result in an unreasonable economic burden. *See* § 11-18- 403.6.2. WSPA requests the District modify these subsections of the Rule to clarify its intent.

Definitions. The definitions in Rule 11-18 reference sources in other rules. If a definition changes in a source rule, it is unclear whether the definition in Rule 11-18 would change automatically. A source rule could potentially change without thorough consideration of effects on Rule 11-18. Thus, WSPA requests that the definitions in Rule 11-18 stand alone and the source citations be deleted from Rule 11-18.

TBARCT. WSPA requests that the District revise the definition of TBARCT to ensure that costs, non-air-quality impacts, and energy requirements are considered. As currently written, the definition of TBARCT outlines four methods by which TBARCT may be determined. One option (§ 204.3) expressly requires the consideration of costs, non-air-quality health and environmental impacts, and energy requirements. The other three do not. Thus, for example, § 204.1 would require use of the most effective technology that has ever been used successfully on that type of equipment, even if site-specific considerations make that technology economically infeasible, and even if the technology would have potentially damaging non-air impacts in an ecologically sensitive area. The District should revise the definition of TBARCT to ensure that all appropriate factors are considered in making the determination.

Section 11-18-204.4 should also be revised to clarify that the District is referring to the controls identified in a MACT standard or an ATCM are those for existing sources, not new sources. EPA's MACT standards for new and existing sources are based on entirely different data sets and impose different levels of control; the fact that EPA has concluded that a specific emissions limit is achievable for a new source that is designed to use a specific technology does not prove that an existing source can be retrofitted to achieve that same level of control (indeed, the persistence of less-stringent MACT limits for existing sources demonstrates that such retrofits are typically *not* possible).

At a broader level, the breadth and vagueness of the definition of TBARCT, and the lack of clarity regarding the District's ability to consider costs in this determination, makes it nearly impossible for the District to properly evaluate the costs associated with Rule 11-18, as currently drafted. Further, there is no indication of what the District may consider to be "technically infeasible" or pose an "unreasonable economic burden." Without much more clear explanation of the parameters of the proposed requirements, WSPA and its members will not be provided a reasonable opportunity to submit data and analysis supporting or opposing the economic and technical feasibility of the draft rule.

Exemptions. The proposed regulation is unlikely to provide any emissions reductions for certain existing source types that are already implementing analogous TBARCT controls for toxics. These source types would include retail gasoline dispensing facilities subject to BAAQMD Rule 8-7, gasoline bulk terminals subject to BAAQMD Rules 8-5, 8-18, and 8-33. WSPA therefore suggests that BAAQMD consider exempting any facilities from Reg. 11-18 that are already subject to requirements that reflect TBARCT.

Prioritization. The District's choice of priorities appears arbitrary. For example, the District specifically notes that diesel particulate matter is the largest contributor to risks in the Bay Area, as illustrated in Figure 5. However, diesel engines are not addressed by the rule until the third implementation phase, and reductions from these sources will not be implemented until 2024, at the earliest.

Section 11-18-405. Section 11-18-405 requires that Risk Reduction Plans be updated if "*health risk posed by a facility...would significantly impact health risks to exposed persons.*" It is unclear whether "*significantly impact*" is a subjective term, or whether the District is referring to the "significant risk thresholds" that are 10-20% of the risk action levels in § 11-18-214. The District should revise this language to clarify that the obligation to update the Risk Reduction plan is triggered only if new information (i) causes a facility to exceed the threshold for preparing such a plan for the first time, or (ii) increases the risk associated with the site by more than the significant risk threshold. The District should also consider in its cost-effectiveness calculations the costs to update these plans and implement new emission reduction technologies pursuant to this requirement.

TIMING ISSUES

Draft Rule 11-18 Should Provide Longer Compliance Timeframes

Several of the provisions proposed in Rule 11-18 require compliance with very tight compliance windows that do not appear to be achievable. The Rule 11-18 Staff Report Table 5 also indicates that the compliance plan implementation due dates will depend upon the industry type or prioritization score. WSPA requests the same plan implementation due date for all Bay Area facilities. A large, complex facility needs more time to plan and install control equipment than a facility that operates one diesel engine. Yet the District plans to require some of the most complex facilities to achieve plan implementation by the year 2019 while a facility that may pose the same health risk to a nearby receptor operating a single diesel engine will not reduce health risk until the year 2027.

Section 11-18-401 requires facilities to submit to the District "*any information necessary to complete an HRA of the facility*" within 30 days of a request. This is an overly ambitious time schedule, given the level of effort needed to obtain the latest emissions information, building dimensions, and other similar information. Facilities may also need to conduct source tests or ambient air sampling to provide accurate data to feed into the HRA. WSPA requests that this timeframe be extended to 180 days. At a minimum, this provision should be amended to allow additional time for extensive requests. Additionally, this requirement is unbound, providing no maximum frequency or criteria for the APCO to request information from a facility to conduct an HRA. This can lead to inequitable or unwarranted regulation of a facility.

Section 11-18-402 sets a deadline to submit a draft Risk Reduction Plan within 180 days of notification from the District that a plan is required. This compliance window does not provide facilities with sufficient time to review the accuracy of the District's HRA, or sufficient time to prepare a Risk Reduction Plan meeting the requirements of § 11-18-403. The time needed to evaluate all potential risk reduction measures for a large, complex facility, including the need to re-run HRAs, analyze impacts, and conduct feasibility analyses for engineering requirements, will require considerably more time than 180 days. WSPA is requesting that this timeframe be extended to three years.

Section 11-18-402 requires implementation of a Risk Reduction Plan "*as soon as feasible*, but by no later than three years" from the date the *draft* Plan was submitted for review. The deadline for implementation should be tied to the date the plan is approved by the District, not the date the draft plan was submitted to the District. Given the extremely tight deadlines imposed by the draft Rule, facilities will need to act quickly to design, order, install, and otherwise implement the required control measures. If the District does not give notice that it disagrees with the facility's Risk Reduction Plan or determination of TBARCT until several months after the Plan is submitted, the facility will likely have already made irreversible financial commitments (*e.g.*, ordering new controls) for equipment that the District has rejected. If regulated facilities are to be able to comply with these requirements effectively and in a timely manner, they require certainty of the requirements that will apply and sufficient time to plan, order, and install equipment. Additionally, multiple process unit shutdowns may be needed to install control devices. Indeed, given the scope of the review and planning required (conducting the necessary engineering studies, evaluating various installation scenarios, obtaining permits, getting CEQA approval, procurement, turnaround planning, construction, start-up optimization, and other requirements), WSPA requests that the three-year timeframe be extended to at least five years from when the Plan is approved, and no earlier than the implementation due date of less complex facilities with only diesel engines.

In addition, the baseline requirement of § 11-18-402 is to implement the Risk Reduction Plan "as soon as feasible" but in no event later than three years from the date of the draft Plan's submittal. However, § 11-18-402.2provides the District with the discretion to "shorten the time period proposed by the facility owner/operator for Plan implementation" to less than three years if the District considers that a shorter timeframe is technically feasible or economically practicable or, alternatively, if the facility impacts a CARE designated area. This provision is unnecessary. Facilities will already be under an obligation to prepare Risk Reduction Plans geared to reducing the facility health risk in as short a timetable as possible, which will require an assessment of the technical and economic feasibility of reducing health risk as quickly as possible. The District will have ample opportunity to discuss questions or suggestions District staff may have with respect to the Plan during the review and comment process. The requirement to implement the Risk Reduction Plan "*as soon as feasible*" renders the provision in § 11-18-402.2.1

allowing the District to require implementation of the Plan "*more quickly*" nonsensical. WSPA suggests that § 11-18-402.2 be removed. Again, WSPA is concerned the Section 402.2 language gives the District unilateral authority to reject the plans of facility project teams in the case of a disagreement.

Assuming § 11-18-402.2 is removed, the definition of "Community Air Risk Evaluation (CARE) Designated Area" in § 11-18-208 should also be removed as the term only applies to § 11-18-402.2.2. If the District chooses to reject WSPA's requests, § 11-18-208 should be revised to be more specific. The first sentence of the definition is ambiguous due to the phrases "*other areas*" and "*may*."

California Environmental Quality Act

The California Environmental Quality Act ("CEQA") requires the District to consider the whole of the action; both direct and indirect environmental impacts from the entire project. Public Resources Code, § 21000 et seq. CEQA is further implemented by the CEQA Guidelines, Title 14, California Code of Regulations, § 15000 *et seq*. Rule 11-18 is being considered for review in an EIR that will also review Rule 12-16, which is part of a suite of regulations identified by the District as the Petroleum Refinery Emissions Reduction Strategy. The combined suite of regulations is part of a larger plan to reduce purported refinery emissions in the Bay Area by at least 20% within just a few years.

CEQA prohibits "segmenting" projects to create the appearance of a lesser degree of impact. The District however consistently limits its analyses to individual rules, excluding consideration of the rules it has recently adopted as part of this "strategy" (Rules 6-5, 8-18, 11-10, 12-15 and 9-14) and the future rules that it is currently developing pursuant to this same strategy. In fact, the District's October 14, 2016 Notice of Preparation does not even mention that Rule 12-16 is part of the suite of regulations that make up the Refinery Project. Rule 11-18 is clearly a component of the Petroleum Refinery Emissions Reduction Strategy, notwithstanding that the rule applies to other stationary sources. The Rule's origin is rooted in the District Board's 2014 resolution to reduce emissions from refineries by 20%, and it is being advanced as an alternative suggestion to draft Rule 12-16, which is squarely directed at refineries. Therefore, the impacts of Rule 11-18 on refineries should be analyzed together with the suite of regulations that make up the Petroleum Refinery Emissions Reduction Strategy. Without a true analysis of the whole project, it is impossible to quantify and understand the magnitude of the impact the adopted and proposed changes will have on the regulated industry.

The District cannot piecemeal the analysis of environmental impacts from the Petroleum Refinery Emissions Reduction project that are clearly derived to work toward the common goal of a 20% reduction target. Furthermore, the District must ensure that its analysis and findings are based upon creditable substantive evidence, that a reasonable range of alternatives are considered, that the project decisions meet the purpose and need, significant impacts are avoided or mitigated and that the whole of the actions is identified and analyzed.

ADMINISTRATIVE COMMENT

Section 11-18-402 refers to "risk action levels set forth in Section 11-18-213." The reference should be to Section 11-18-214, not -213. WSPA would ask the District to review this for amendment.

Attachment B
WSPA Comments on Proposed Regulation 12, Rule 16

As the District is aware, WSPA submitted comments on the District's Project Description for Rule 12-16 on September 9, 2016. The draft Rule language now being workshopped does not address the many issues that WSPA raised in our September comment letter. WSPA continues to have significant concerns with the conceptual goal of draft Rule 12-16 and with the practical implementation of the rule's provisions. WSPA hereby incorporates by reference the various comments it has previously made to the District on the conceptual basis of draft Rule 12-16.

While WSPA has a number of specific concerns with the District's analysis (discussed in more below), WSPA strongly supports the concerns voiced in the Staff Report that the proposed rule conflicts with the District's authority under the federal Clean Air Act ("CAA") and the California Health & Safety Code ("H&SC"), will interfere with the State's cap and trade program for GHGs, is not necessary, and will not provide significant real benefits. Staff Report at 17-20, 38-40.

LEGALITY

WSPA's concerns over the legality of emissions caps have already been transmitted to the District separately. WPSA incorporates by reference the comments it submitted in July 2016 and September 2016.[2]

In general, WSPA agrees with District Staff's assessment that draft Rule 12-16 would not withstand judicial scrutiny. As the District acknowledges in the Staff Report, draft Rule 12-16 is inconsistent with existing federal and state air programs, selectively targets petroleum refineries without a showing of necessity, would not be in harmony with the state cap and trade program for greenhouse gas emissions, arbitrarily limits specific refinery emissions to levels that are not necessary to protect local communities, and is beyond the District's statutory authority.

The Staff Report suggests that the District is continuing to develop draft Rule 12-16 with the goal of proposing the rule to the Board for adoption. It is unclear why draft Rule 12-16 is continuing to be developed when District Staff believe that the rule "would likely be found to be beyond the Air District's authority and/or arbitrary and capricious by a Court." Staff Report, at page 3. The structure of the draft rule and its underlying policy objectives are unquestionably unjustified, for the reasons set forth in WSPA's prior comment letters and the District's own Staff Report. Given the significant concerns District staff and the Bay Area refineries have expressed over the legality of the draft rule's provisions, the District should not continue planning to propose Rule 12-16 to the Board for adoption. To the extent that the District must report to the Board on the development of CBE's idea, District staff should simply prepare a report describing the rulemaking, staff's analysis of the draft language that was developed, staff's conclusion that the rule would be illegal if adopted, and an explanation why the draft Rule is not being proposed to the Board.

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[2] Marne S. Sussman (Pillsbury Winthrop Shaw Pittman LLP), letter to Honorable Chair Mar, and Members of the Board of Directors, Bay Area Air Quality Management District, "Re: Legal Issues Pertaining to Refinery Emission Cap Option for Proposed Regulation 12-16", July 19, 2016; Kevin Buchan (WSPA), letter to Mr. Gregory Nudd, "Subject: WSPA Comments on BAAQMD's Draft Project Description for Regulation 12, Rule 16 and Regulation 11, Rule 18," September 9, 2016.

GHG Caps are Ineffective and Counterproductive

Greenhouse gas emissions are a global issue, not a local community-based issue. Local greenhouse gas (GHG) caps for refineries in the Bay Area Air Quality District are likely to simply shift GHG emissions elsewhere. This has been recognized by District staff, the District's Advisory Council, the California Air Resources Board (ARB), and the Intergovernmental Panel on Climate Change (IPCC). WSPA summarized comments by District Staff, the District Advisory Council, ARB and the IPCC previously.[3] The October 2016 Staff Report for Rule 12-16 provides additional support that caps may result in increased GHG emissions from shipping imported fuels to California.[4]

Moreover, Bay Area refineries are very energy efficient. ARB published a summary report in mid-2013 showing that the 5 Bay Area refineries subject to ARB's "*Regulation for Energy Efficiency and Co-Benefits Assessment of Large Industrial Facilities*" have implemented hundreds of projects to reduce GHG emissions. The ARB report states that approximately 78% of the estimated 2.8 million metric tonnes per year of GHG reductions associated with these projects have already been achieved.[5] A third party review by San Francisco State University concluded that the refinery project reports demonstrated "*a thorough effort*."[6] The results of ARB's refinery energy efficiency audits strongly suggest that opportunities for significant energy efficiency gains in this sector are limited at best.
To the extent that the District wants to set caps that curtail fuel production at Bay Area refineries, this will simply result in more fuels being produced at other refineries. For refineries outside the state, there is a very real possibility those refineries may be less energy efficient; this would be counterproductive to the District's objective.

Additionally, the application of the localized GHG caps under the jurisdiction of the BAAQMD would result in severely disadvantaging the local refineries relative to refineries located elsewhere in the event new CARB or EPA fuel standards are enacted that would require new process units. EPA and CARB periodically update the motor fuel specifications to ensure that the cleanest fuels possible are available. The application of a facility GHG Cap at historic levels may lead to the shutdown of one or more of the regional refineries because Reg. 12-16 will not allow any increases in GHG emissions regardless of any net environmental benefit. The EIR for this rule should carefully consider this aspect of the rule and estimate the global GHG emission impacts.

Caps Based on Historical Emissions are Technically Problematic

Not only are the proposed emissions caps in §§ 12-16-301 to -305 duplicative of existing federal and state programs targeted at reducing toxic emissions, they are also technically problematic and could potentially require refineries to cut production altogether or risk non-compliance.

As WSPA has previously described, facilities purchase capital equipment today based on what may happen in the future. The District, and every other air permitting jurisdiction in the United States, issues air permits based on the impacts of a facility's *potential* emissions. In California, refineries pay to offset the *potential* emissions at the time the equipment is permitted. For the District to now propose capping emissions based on actual emissions levels from 2010-2014 raises significant Takings concerns and

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[3] *See* WSPA Comment Letter, September 9, 2016.
[4] Draft Regulation 12, Rule 16: Petroleum Refining Facility-Wide Emissions Limits AND Draft Regulation 11, Rule 18: Reduction of Risk from Air Toxic Emissions at Existing Facilities, Draft Staff Report, October 2016, p.23.
[5] Energy Efficiency and Co-Benefits Assessment of Large Industrial Sources; Refinery Sector Public Report; California Air Resources Board Stationary Source Division; June 6, 2013: http://www.arb.ca.gov/cc/energyaudits/eeareports/refinery.pdf
[6] Air Resources Board staff presentation, Energy Efficiency and Co-Benefits Assessment Public Reports Workshop, June 30, 2015, slide 30: https://www.arb.ca.gov/cc/energyaudits/meetings/063015/presentation.pdf.

conflicts with these other District regulatory programs (which continue to exist). Further, the proposed emissions caps in §§ 12-16-301 to -305 would be inconsistent with refineries' existing permit limits, which in most cases were specifically designed (and paid for) by the refineries to ensure necessary operational flexibility.

The specific historical emissions baselines chosen are similarly problematic. First, refineries have found that the values in the proposed regulation that are supposedly based in reported emissions do not match the official records of reported emissions. Second, as the District's own Staff Report makes clear, the selected baseline period encompasses a period of artificially low demand, coming out of the last Recession. Staff Report at page 21, Figure 3. As a result, Rule 12-16, as currently drafted, would "lock in" this temporary drop in demand as a permanent, facility-wide cap. At a minimum, the District's economic analysis must evaluate the significant impacts of imposing the cap at such an artificially low level that does not reflect current or anticipated future demand.

The methodology by which this cap is calculated and revised also raises significant concerns. As currently drafted, Rule 12-16 would require ongoing revisions to these caps (each of which would require Board approval) whenever the methods used to calculate emissions changed. Yet the proposed baselines in §§ 12-16-301 to -305 are themselves based on annual emissions calculations from years 2010-2014 that were developed using different emissions calculation methodologies than are being used today. In other words, the current rule is comparing apples and oranges: the District calculated historic actual emissions (the values that the proposed caps are based on) differently than it currently requires actual emissions to be calculated, and differently than it will require the caps be recalculated in the future when the methodologies change once again; yet these changes are never evaluated for consistency against the original methodology that was used to calculate the initial cap. As a result, the caps under which the Refineries will be required to operate will routinely fluctuate based solely on methodology changes, which may not accurately reflect the "real" emissions that the caps purportedly reflect. For most sources, the District's current emissions inventory guidelines (Guidelines) significantly deviate from the methods that the District has used in previous years. The Guidelines require reporting emission sources, including cargo carriers, road dust, and equipment maintenance emissions, which the District has not included in previous emission inventories. The Guidelines specify emission factors that may not have been used in previous emission inventories. Similarly, in the case of California's GHG reporting rule, there have been changes with respect to which sources are reported and how they had to go through a regulatory approval process.

The nature of the Guidelines themselves further exacerbates this concern. The District's current Guidelines are not yet finalized, meaning that WSPA and its members cannot fully and fairly evaluate how the final Guidelines may change the calculation methodologies as compared to the prior reported emissions inventories on which the caps are based. Furthermore, these Guidelines can be changed at any point in the future without a public Board action – and frequently, as the District's own practice has made clear, without involving or informing stakeholders. Thus, the refineries may not have sufficient time to respond or even be informed of changes to the Guidelines that affect compliance with the limits. Board approval of changes to the limits that incorporate changes to the Guidelines may never occur, or may occur at a date too late for refineries to comply with the annual limit.

Similarly, the "*Determination of Compliance Procedure*" in § 12-16-601 refers to an as-yet unwritten part of the District's Manual Of Procedures. If the compliance procedure is not finalized by rule adoption, it may not be possible for the refineries to comply. Sufficient time is needed to implement compliance.

Finally, the January 1, 2018 compliance deadline does not provide enough time for refineries to comply with Rule 12-16. The refinery emissions estimates using the Guidelines may not even be finalized by January 1, 2018 due to the iterative review, corrective action, APCO Action and public inspection process provided in § 12-15-402. Once the emission calculation methods and estimates are finalized, baseline emissions would need to be updated in order to obtain Board approval of changes to the limits. The emission estimation method must be finalized for a refinery to implement a compliance program. The refineries cannot reasonably plan to comply with Rule 12-16 by January 1, 2018, when the actual emissions limits – or, indeed, even the methodology by which those limits will be determined – may well be unknown as of that date.

California Environmental Quality Act

The California Environmental Quality Act ("CEQA") requires the District to consider the whole of a Project; both direct and indirect environmental impacts from the entire project. Public Resources Code § 21000 *et seq*. CEQA is further implemented by the CEQA Guidelines, Title 14, California Code of Regulations, § 15000 et seq. Rule 12-16 is part of a suite of regulations identified by the District as the Petroleum Refinery Emissions Reduction Strategy. The combined suite of regulations is part of a larger plan to reduce purported refinery emissions in the Bay Area by at least 20% within just a few years.

CEQA prohibits "segmenting" projects to create the appearance of a lesser degree of impact. However, the District consistently limits its analyses to individual rules, excluding consideration of rules it has recently adopted as part of the Petroleum Refinery Emissions Reduction Strategy (Rules 6-5, 8-18, 11-10, 12-15 and 9-14) and the future rules that it is currently developing pursuant to this same strategy. In fact, the District's October 14, 2016 Notice of Preparation does not even mention that Rule 12-16 has been part of the suite of regulations that make up the Refinery Project since the initial inception of that Project. Without a comprehensive analysis of the whole project, it is impossible to quantify and understand the magnitude of the impact the adopted and proposed rules will have on the regulated industry.

The District cannot piecemeal the analysis of environmental impacts from the Petroleum Refinery Emissions Reduction Project that are clearly derived to work toward the common goal of a 20% reduction target. Furthermore, the District must ensure that its analysis and findings are based upon creditable substantive evidence, that a reasonable range of alternatives are considered, that the project decisions meet the purpose and need, significant impacts are avoided or mitigated and that the whole of the actions is identified and analyzed.

December 2, 2016

Eric Mar, Chair of the Board
Jack Broadbent, Executive Director
John Gioia, Stationary Source Committee Chair
Members of the Board of Directors
Bay Area Air Quality Management District
375 Beale Street, Suite 600
San Francisco, California 94105

Re: Health and Safety Commentary Pertaining to Rule 12-16 and 11-18

Dear Chair Mar, Executive Director Broadbent, Committee Chair Gioia, and Board members,

We are writing as public health and medical professionals and experts to comment on rules under consideration by the Bay Area Air Quality Management District (BAAQMD, Air District) to address harmful emissions of air pollutants. We particularly want to convey the importance of Rule 12-16 to the health of Bay Area residents. Air pollutants are an important cause of disease and death in California and the world, presenting an enormous global burden of disease.

At the outset, we want to note that grave potential changes at the Federal level make imperative local, regional, and state actions to ensure clean air for current and future generations. We hope the BAAQMD, other California air quality districts, and the California Air Resources Board will take even greater leadership in actions affecting the future of our planet.

We also understand the Bay Area must anticipate and plan for economic and population growth, with a significant portion assigned to Contra Costa County.[1] Managing growth in a healthy and sustainable way involves altering underlying systems that drive pollution. At a minimum, avoiding increased pollution from any existing sources is critical.

We are looking to the Air District to take on these major challenges to provide healthy air for all in the Bay Area and to lead the way on local actions that reduce releases of greenhouse gases.

We are therefore interested in the Air District's efforts to reduce hazards associated with the Bay Area refineries. We are concerned that Bay Area refineries are shifting to an even heavier, lower quality feedstock derived from tar sands bitumen. We understand that this shift requires changes to the refineries' infrastructure and methods. We understand the Air District is aware the influx of tar sand crudes is under way and recognizes:

> The use of lower quality crude at refineries could potentially mean increased emissions of air contaminants such as sulfur containing pollutants from sulfur recovery facilities. Emissions could also increase as a result of accidents related to the increased corrosiveness of lower quality crudes. Processing lower quality crudes also requires more intense processing and higher energy requirements, which can result in increased air emissions.[2]

To address these health threats, this letter comments on two proposals under the Air District's review, one to address potential increases in criteria pollutant and greenhouse gas emissions at the refineries and the other to reduce emissions of toxic air contaminants at sources throughout the Bay Area.

The first, Regulation 12, Rule 16, would limit emissions to current levels through enforceable numeric limits on refinery-wide emissions of greenhouse gases (GHG) and particulate matter, thereby preventing increases in emissions of criteria air pollutants and greenhouse gases from Bay Area refineries. By extension, it would reduce pet coke and diesel-related exposures, since pet coke is a major byproduct of dirtier feedstock and since import/export transit will increase with an influx of tar sands. These increases would occur if the refineries processed the dirtier forms of crude oil.

Rule 12-16 would play an important role in avoiding further impairment or degradation of Bay Area air quality from the refineries. The rule would reduce the regional burden of pollution, which will produce health and safety benefits, especially for those proximate to or working in the refineries.[3] It presents the opportunity to avoid increases in net GHG emissions and is in keeping with California's climate change mandate, whereas tar sands refining will clearly impede California from meeting GHG reduction targets.[4]

The Air District is also proposing Regulation 11, Rule 18 to reduce risks from emissions of toxic air contaminants at a wide array of sources in the Bay Area including but not limited to the refineries. Rule 11-18 would broaden the sources for which risks are assessed, set a more protective standard for risks of toxic air contaminants, and incorporate updated toxicity values issued by the Office of Environmental Health Hazard Assessment of the California Environmental Protection Agency (EPA). These are important issues, and with improvements such as tightening the monitoring-to-response timeframe, Rule 11-18 could be an important health effort.

We urge the Air District to go forth with the next step of review for both rules, but to consider them *separately*. They are complementary but fundamentally different, and they address different pollutants. Both can be justified on health grounds.

Below is further elaboration that speaks to the importance of Rule 12-16:

1. Tar sands (bitumen) air emissions will be much greater than those involving current oil feedstock and will carry disproportionately more GHG, particulate matter including sulfates and heavy metals, and sulfur dioxide.[5] Tar sand refining is also more corrosive and presents disproportionately high occupational hazards.

2. A particularly important direct consequence of tar sand refining in the Bay Area may be the resulting increase in emissions and exposure to particulate matter (PM) including PM10, PM2.5, and ultrafine particles (ultrafines, UF). As stated by the Air District, ". . . PM [Particulate Matter] is still by far the air pollutant most harmful to public health in the Bay Area," accounting for 90% of air pollution-related deaths here.[6] The refining of heavier crudes will increase particulate and sulfur dioxide (a PM precursor) concentrations significantly more than refining of traditional crude oils. Moreover, PM from heavy crudes, particularly tar sands (bitumen), will be more toxic, carrying much more of the highly dangerous heavy metals and elements such as vanadium, nickel, and lead.[7]

3. Decades of research have firmly established that exposure to particulate matter is associated with severe health effects, including premature mortality, cardiovascular and pulmonary disease, heart attacks, strokes, and cancer.[8] For example, the U.S. EPA and the World Health Organization (WHO) find that a 1 μg/m^3 increase in PM2.5 is associated with a 1.6% increase in death from cardiovascular disease,[9] and emerging research suggests that UFs pose at least as great a risk for morbidity and mortality as does PM2.5.[10] Physical, neurological, and cognitive adverse effects of air pollution on infants and children have been established, with significant, long-term implications for the individual, their family, and society.[11] Infants and children, the elderly, and those socio-economically disadvantaged, especially those closest to the refineries, are at greatest risk of exposure and are more susceptible to adverse effects of exposure.[12] Poorer communities, largely of color, are both closest in proximity to Bay Area refineries and disproportionately vulnerable to their adverse effects, making an influx of tar sands an environmental justice violation.

4. There are no safe levels of these air pollutants, and every incremental increase of emissions from tar sand refining will increase adverse health outcomes. Bay Area air quality is impaired and in nonattainment for ambient standards for ozone, PM10, and PM2.5[13] (harmful ultrafines are essentially unregulated). While attainment standards are a strategy for advancing health, the California EPA, the U.S. EPA and the WHO all clearly state that the standards do not represent safe levels for exposure to air pollution and its constituents.[14] Moreover, they document that important health effects occur below the existing ambient standards. Therefore, Bay Area residents are already burdened and experiencing excess health consequences from air pollution and any increase in emissions will increase adverse health outcomes.

5. Disproportionately large increases in greenhouse gases emissions will contribute to serious health hazards posed by climate change. The U.S. EPA, under The Clean Air Act, issued an endangerment finding in 2009, concluding that GHG, ". . . endanger both the public health and the public welfare of current and future generations."[15] GHG-associated climate change already endangers health in the Bay Area, with increased risks anticipated in the near future.[16] Very few years are left to reduce GHG emissions and avoid the most severe health consequences.

6. A cap-and-trade alternative to Rule 12-16 would not protect health in the Bay Area. By failing to abate local increases in particulate matter, its toxic constituents, diesel particulate matter, pet coke, and worksite hazards, increasing tar sand pollution in the Bay Area in exchange for potential GHG reductions elsewhere would fail to protect the health of Bay Area residents – especially proximate communities and workers. Assembly Bill 32 (AB32) requires consideration of communities already adversely impacted by air pollution, prohibits measures that place disproportionate burdens on vulnerable communities, and limits market-based mechanisms to those that do not increase toxic air contaminants or criteria air pollutants.[17]

In conclusion, the Air District's own mission, as well as the legislative intent of CEQA and AB32, empower and call upon you to protect the health and air of the Bay Area.[18] We respectfully submit that limiting refinery emissions as outlined in Rule 12-16 is an appropriate course of action. We ask that Rule 12-16 be fairly considered in the upcoming review process, and ultimately adopted.

Thank you for your consideration.

Signed,

Bart Ostro PHD	Former Chief of Air Pollution Epidemiology Section, California EPA, currently Research Faculty, Air Quality Research Center, UC Davis
Amy D Kyle PhD, MPH	School of Public Health, University of California Berkeley (Institution for identification only)
Claire V Broome, MD	Adjunct Professor, Rollins School of Public Health Emory University Assistant Surgeon General, US Public Health Service (retired)
Linda Rudolph MD MPH	Director, Center for Climate Change and Health Oakland CA
Jonathan Heller PhD	Co-Director and Co-Founder, Human Impact Partners Oakland CA
Wendel Brunner MD, PhD, MPH	Former Director of Public Health, Contra Costa Health Services
Kathy Dervin MPH	Senior Climate and Health Consultant, Berkeley CA
Janice L Kirsch MD MPH	Medical oncologist and hematologist
Heather Kuiper DrPH MPH	Public Health Consultant, Oakland CA

HIP
HUMAN IMPACT PARTNERS

Center for
Climate Change & Health

Cc: Victor Douglas

Endnotes present a sample of the sources supporting this letter.

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A CBE Technical Report
2 December 2016

Combustion Emissions from Refining Lower Quality Oil

Part 2: How Much Could a Switch to 'Tar Sands' Oil Increase Direct Emissions of $PM_{2.5}$ and CO_2 from Northern California Refineries?

Greg Karras, Senior Scientist,
Communities for a Better Environment (CBE)

CONTENTS

Abstract

Emissions from refining lower quality oil were estimated in the San Francisco Bay Area, where the second largest refining center in western North America is replacing declining current oil supplies with oil imports, and refinery emission limits are now proposed. Data for refinery crude feed, processing, yield, fuels, crude availability and cost, infrastructure plans and projects, and emissions were analyzed to identify a range of plausible worst-case refinery crude feed, energy consumption, and emissions scenarios. The quality of the regional crude feed could worsen from 2020–2050 as 50–80 percent of it is replaced with blends of heavy oil and bitumen. A peer reviewed method that predicted oil quality effects on Bay Area refining energy and emission intensities within 5 percent of those observed during 2008 and 2014 estimated emissions in these "tar sands" oil scenarios. Estimated refinery CO_2 and $PM_{2.5}$ emission intensities increased by ≈39–100 percent in these scenarios, increasing regional mass emissions from refineries by ≈5.9–16 million metric tons per year of CO_2 and ≈390–990 metric tons per year of $PM_{2.5}$.

Introduction

The San Francisco Bay Area hosts the second largest oil refining center in western North America after Los Angeles.[1] Chevron, Phillips 66, Shell, Tesoro, and Valero currently operate the five major refineries here. Collectively, Bay Area refiners produce gasoline and diesel in excess of northern California demand, dominate statewide exports of these fuels even after supplying some of the demand in southern California and other western states,[2] and emit more fine particulate matter and greenhouse gases than any other industrial sector in the Bay Area.[3]

Processing lower quality crude oil is known to increase refinery pollution rates,[4–22] and Bay Area refiners are known to be switching crude feeds as their current crude supply sources in California and Alaska decline.[26–29] Analysis of resource availability and climate constraints indicates that it is feasible, and more economic for society, to avoid low quality, high-emitting oils.[30] However, crude can account for up to 90 percent of a refiner's operating costs,[7] price discounts on low quality oils can exceed 18 percent,[31–34] and Bay Area refiners have announced plans to refine low quality oil[35–44] and have proposed infrastructure projects that could enable those plans.[45–59]

On 14 October 2016 the Bay Area Air Quality Management District (BAAQMD) proposed new Rule 12-16 and requested public comment on the scope of environmental review for this proposal. Proposed Rule 12-16 would establish limits on facility-level emissions of particulate matter air pollution ($PM_{2.5}$, PM_{10}, NO_x, and SO_2) and greenhouse gases (CO_2e) from oil refining in the Bay Area, set at levels that would prevent any significant increase in current annual emissions of these air pollutants.

A complete and accurate environmental review of this proposal to prevent increases in these emissions must, among other things, describe the potential increases in these emissions that the proposal, if implemented, would prevent. Thus, questions regarding whether potential crude feed quality-driven increases in these emissions can be estimated based on currently available information, and how much these emissions could increase in the plausible worst-case scenario, fall within the scope of this environmental review. This report addresses these questions.

Summary of Site-specific Oil Feed Quality Impacts Observed

Impacts of crude feed switching on Bay Area refinery feedstock contamination and pollution rates have been observed many times over more than twenty years.

In 1994 CBE showed that increased selenium (Se) discharges into the San Francisco Bay-Delta estuary were linked to denser, higher-selenium crude feeds.[4] In perhaps the first documented case of Bay Area refinery pollution violations linked to lower quality oil, Se discharges from the Rodeo, Martinez, and Benicia refineries exceeded their discharge limits. Se was concentrated in denser components of their crude feeds, released into the sour gas and sour water streams from coking and hydroprocessing, and passed through partial waste water treatment to discharge, on a mass per barrel refined basis, at rates reaching ten times those of other plants running lower-Se crude feeds.[4] When differences in waste water treatment were accounted for, the Se content of Bay Area refinery crude feeds predicted the refiners' Se/barrel discharge rates almost perfectly (R^2, 0.99).[4]

In 1999 a switch to lower quality, denser crude was a contributing factor in a catastrophic fire during crude unit maintenance work that killed workers and caused a massive air pollution plume at the Avon refinery near Martinez.[5] A U.S. Chemical Safety Board investigation of the incident found that the denser crude overwhelmed a crude desalting unit, resulting in corrosion product plugging of a crude unit pipe downstream which was undetected until the plug released during maintenance, fueling the catastrophic fire.[5]

In the mid-1990s Chevron expanded the capacity of the fluid catalytic cracking (FCC) unit at its Richmond refinery, increasing the refinery's capacity to process separately delivered heavy gas oil as a larger portion of its total oil feedstock. In 2011 the refiner used this capacity to process a total oil feed that, although lower in total crude-plus-gas oil volume, was proportionately higher in heavy gas oil than it processed in 2008.[6] Making gasoline and other engine fuels from heavy gas oil, the densest and most contaminated fraction of whole crude that distills in atmospheric and vacuum crude distillation, requires more energy-intensive carbon rejection and hydrogen addition processing than making the fuels from lighter crude fractions. Thus, refining proportionately more heavy gas oil would have increased the Richmond refinery's energy intensity, and consequently its CO_2 emission intensity, in 2011 as compared with 2008.[6] Reported data confirmed this expected emission intensity effect. The refiner's emission intensity (kg CO_2e/m^3 oil processed) increased in 2011, as compared with 2008.[6]

On 15 January 2007 a major fire in the Chevron Richmond refinery crude unit caused an air pollution plume over parts of Richmond and Marin County. Sulfidic corrosion, a damage mechanism in steel equipment that processes sulfur-containing oils at high temperatures, led to the crude unit pipe failure in this incident.[7] A subsequent incident investigation found that a switch to higher-sulfur crude, which had accelerated sulfidic corrosion,[7] was a contributing factor in the refiner's corrosion-incident emissions.

An April 2007 analysis of the causes of flare emissions at Bay Area refineries showed that refining denser and higher-sulfur crude feeds contributed to recurrent flare emission incidents caused by conversion-product gas imbalances at the refineries.[8]

In 2008 the Western States Petroleum Association (WSPA) reported that the total crude feed for Bay Area refineries contained an average mercury (Hg) content of ≈ 5.07 µg/kg.[9] This analysis was required by the Regional Water Quality Control Board after a U.S. EPA study[10] noted that exceptionally high-Hg crude streams from one source area supplying Bay Area refineries could be expected to result in elevated Hg emissions from refineries processing those streams. The WSPA report did not fully account for the disposition and fate of the Hg in these oils, however, it did show an impact. As compared with the weighted average Hg content of the nationwide refinery crude feed (2.9–4.1 µg/kg),[10] the higher Hg content WSPA reported (5.07 µg/kg)[9] documented elevated mercury levels in Bay Area refinery crude feeds.

In 2009–2010 the Phillips 66 San Francisco Refinery commissioned a new heavy gas oil hydrocracker and, with Air Liquide, a new fossil fuel fed hydrogen steam reforming plant that replaced a smaller hydrogen plant the refiner decommissioned at its Rodeo facility. The new hydrocracker increased the refiner's capacity to process lower quality, denser oil and the expanded steam reforming, an energy-intensive process that produces more CO_2 than hydrogen by mass, enabled that added hydrocracking by supplying more hydrogen. The use of this new infrastructure for refining lower quality oil increased the refiner's total CO_2e emissions substantially from pre-project (2008–2009) levels.[6]

In August 2012 twenty refinery workers narrowly escaped death and some 15,000 people sought emergency medical attention for pollution-related symptoms after a catastrophic pipe failure in the Chevron Richmond refinery crude unit spewed hot hydrocarbons that ignited in a major fire and air pollution incident.[7] Sulfidic corrosion that was accelerated by a switch to higher sulfur crude led to the catastrophic pipe failure. In the years before this incident Chevron switched the refinery's crude feed sources dramatically, from approximately 88% Alaskan North Slope (ANS) crude in 1998 to ≈ 62 % imported crude oils that were higher in sulfur than ANS by 2003 and ≈ 77 % imported crude by 2008.[1, 15] The U.S. Chemical Safety Board's investigation found that this switch to higher sulfur, more corrosive crude was a contributing factor in the 6 August 2012 incident.[7]

From 1990–2014 Bay Area refiners built at least 40 million barrels per year of new heavy oil cracking capacity (coking, FCC, and hydrocracking) and, based on the best available estimates by the BAAQMD and California Air Resources Board for this period, their total CO_2e emissions increased by ≈ 3.4 million metric tons per year.[6] This emissions increment from 1990–2014 is linked to that long lasting, higher-emitting infrastructure for refining lower quality oil.[6]

Recently released data from 2014 further confirm a previously reported finding based on data from 2008: a denser crude feed that requires more processing energy than the U.S. average has driven the total greenhouse gas emission intensity of Bay Area refineries higher than the U.S. refinery average. First reported in 2010 based on direct observations,[11] this finding is supported by additional peer-reviewed work[12, 18–22] reported from 2010–2015, and is now further supported by recently reported data from northern California refining industry operations during 2014.[13–17]

Past Estimates of Oil Feed Quality Effects on Refining Energy

Crude oils are complex and widely ranging mixtures of hydrocarbons and contaminants. Crude has larger multi-carbon hydrocarbons, higher carbon and contaminant content, and lower hydrogen content than the major products refiners make from crude, the engine fuels gasoline, diesel, and kerosene jet fuel. These same bulk characteristics make crude oils denser and hydrogen-poor compared with the engine fuels made from them. The differences can be substantial when the wide range of crude oils is taken into account. For example, the average annual crude feeds processed in major U.S. refining centers and California range in density from ≈ 858–902 kg/m^3 as compared with densities of ≈ 737, 814, and 845 kg/m^3 for gasoline, kerosene, and diesel, respectively.[11, 12]

Making engine fuels from crude oils thus requires breaking the larger hydrocarbons in crude into smaller, fuel-sized compounds (cracking), adding H_2 to these hydrogen-poor cracked hydrocarbons, rearranging their chemical structures, and removing their contaminants to protect refinery process catalysts and meet product specifications.[11] Major processes that work harder and process more of the barrel when refining lower quality oil include coking, catalytic cracking, heavy oil hydroprocessing, hydrogen steam reforming of fossil fuels to produce hydrogen needed for that hydroprocessing, and vacuum (heavy oil) distillation.[11, 12, 18–22] These processes use extreme heat, pressure, and chemical energy—notably hydrocarbon feedstock energy conversion to hydrogen and CO_2 in steam reforming, and chemical catalysts that are reactivated by combustion—and are major energy consumers in refineries.[11, 18–21] Consequently, refining lower quality oil increases the processing, energy, and emission intensity of oil refining.

By 2010 peer reviewed research had described the crude feed quality-driven changes in refinery energy intensity quantitatively and showed crude feed quality can predict average multi-plant refinery energy and emission intensity based on real-world U.S. oil refining data.[11] This research[11] compared refinery crude feed, processing, yield, and fuel data from four regions accounting for 97% of U.S. refining capacity during 1999–2008 among regions and years for effects on processing and energy consumption predicted by the processing characteristics of denser, higher sulfur oils. Crude feed density and sulfur content could predict 94% of processing intensity, 90% of energy intensity, and 85% of CO_2 emission intensity differences among regions and years and drove a 39% increase in emissions across regions and years. Fuel energy for processing increased by $\approx$ 61 MJ/m^3 crude feed for each 1 kg/m^3 sulfur and 44 MJ/m^3 for each 1 kg/m^3 density of crude refined. Differences in refinery products, capacity utilized, and fuels burned were not confounding factors. Fuel energy increments observed predicted that a global switch to "tar sands" oils, should that occur, could double or triple refinery emissions of carbon dioxide from fuel consumption to process the oil.[11]

By 2015 several other independent research efforts quantified oil quality effects on refinery energy intensity using either observed data,[12] or more detailed process-specific modeling based on engineering assumptions and additional details of plausible crude feeds.[18–21] These efforts further supported the effect of oil quality on refinery energy intensity the previous work documented based on U.S. refinery observations,[11] reporting energy and emission intensity effects of similar scale for comparable oil quality, process configuration, and product slate assumptions. Some of these more detailed methods[20–21] may yield more accurate estimates of oil quality-driven energy and emission impacts than the 2010 method,[11] especially for estimating impacts at individual refineries—so long as data those methods require are reported publicly. Cautions against estimating energy and emissions at individual refineries based on oil density and sulfur content alone without considering more detailed plant-specific data appeared in all of this work, and some of it illustrated these plant-level limitations quantitatively.[11–12, 18–21] However, data required for the more detailed methods—such as crude feed hydrogen content, the volume and quality characteristics of specific crude feed distillation fractions, process-level inputs and outputs, and plant-specific product slates—are not yet publicly reported and available for Bay Area refineries.

In 2015 research that assumed up to half of the U.S. crude feed could be replaced by diluted bitumen oils from Canada with only minimal refinery equipment changes found increased petroleum coke combustion could increase $PM_{2.5}$ emissions from FCC units by up to 25 %.[22] These assumptions may not apply to the Bay Area industry—which gets undiluted heavy oils from sources worldwide[15] and has launched major infrastructure projects.[6, 35–39] Also, this research did not estimate refinery-level impacts, and as it notes,[22] it did not estimate SO_2 or $PM_{2.5}$ emissions from refinery-wide burning of the highly contaminated gases that severe coking of bitumen-derived oils can exacerbate.

A 2012 study sponsored by Chevron[23] reported oil quality-driven increases in refinery energy and emissions based on unverifiable estimates that fell below those reported by other work.[11–21] This study[23] assumed a better quality worst-case crude feed than those observed, relied on undisclosed processing assumptions that could not be verified, reported worst-case energy and emission increments smaller than those observed, and made substantial errors in its comparisons with other work.[24–25] For these reasons this study[23] is noted for completeness but is not used in the analysis herein.

Importantly, the estimation method reported in 2010 was shown to predict the average energy intensity (*EI*) of California and Bay Area refineries well. This method[11] uses observed data from U.S. refining regions[†] to estimate refining *EI* based on a given refining region's observed crude feed density, crude feed sulfur content, product slate, and operable crude capacity utilization.[††] It predicted average California refinery *EI* during 2004–2009 within 1 % (5.27 GJ/m^3 predicted *v.* 5.32 GJ/m^3 observed).[12] Further, it predicted the average Bay Area refining *EI* in 2008—which was observed from actual

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[†] Observed data inputs include energy intensity *(EI)*, the total refinery process energy consumed per volume of crude feed, based on reported fuels consumed in GJ/m^3 crude refined; crude feed density *(d)* in kg/m^3 crude refined; crude feed sulfur content *(S)* in kg/m^3 crude; the utilization of operable atmospheric distillation capacity *(CapUt)* in percent; refined products ratio *(Pratio)*, the volume of gasoline, kerosene, distillate, and naphtha divided by that of other refinery products.[11]

[††] Statewide during 2004–2009 all of these data (*d, S, CapUt, Pratio*) were observed actuals; for northern Calif. refineries these data were either observed actuals (2008: *d, S;* 2014: *d, S, CapUt*) or West Coast (2008: *CapUt, Pratio*) or statewide (2014: *Pratio*) observed actual data "defaults."

reported Bay Area refining CO_2 emissions of 360 kg CO_2e per m^3 crude and the 68.4 kg CO_2 per GJ emission intensity of the West Coast refinery fuel mix that year—within 1 % (5.31 GJ/m^3 predicted *v.* 5.26 GJ/m^3 observed).[11] In 2011 analysis using more complete Bay Area crude feed and California refinery process fuels and product slate data also showed that this method predicted Bay Area refinery *EI* during 2008 within 1 % of observed statewide *EI* that year.[12]

Data that became available by the summer of 2016[12–17] allow for an additional test of the estimation method reported in 2010[11] for estimating changes in the energy intensity of Bay Area refining based on changes in crude feed quality. These northern California-specific refining industry data are summarized in Table 1.

As shown in Table 1, the energy intensity (*EI*) of Bay Area refining that is predicted by the estimation method reported in 2010[11] based on reported average Bay Area refinery crude feed quality in 2014 is within 2 % of that actually observed from reported refinery emissions in 2014 and average refinery fuels consumed. Moreover, when the relationship of refinery feedstock to refinery products is considered, the sensitivity analysis summarized in the table shows that the method predicts refinery energy intensity well despite residual uncertainty about refinery product slates.

The "sensitivity cases" analyzed assume a ratio of gasoline, diesel, kerosene and naphtha to other refined products (products ratio) that is either 20 % lower or 20 % higher than the average observed statewide from 2004–2009 (the "SC–20%" and "SC+20%" cases in Table 1). This is a very conservative assumption, especially for the –20% case, because the statewide crude feed from 2004–2009 was denser than the Bay Area crude feed in 2014,[12, 14–15] and energy-intensive refining increases the portion of denser crude that is converted to gaseous and solid byproducts instead of engine fuels. Nationwide data show that refinery products ratios tend to decrease with increasing crude feed density and refinery energy intensity, and refinery yield tends to shift, from gasoline and diesel to coke and fuel gas, as crude feed quality worsens and refinery *EI* increases.[11] Indeed, the inverse relationship between products ratio and *EI* (which is weak) is explained in large part by the difficulty of maintaining light liquids yield from much denser crude. Thus, if the Bay Area products ratio in 2014 differed from that observed during statewide refining of relatively denser crude, it most likely was closer to the "SC+20%" case (prediction within 1 % of observation). Moreover, in all cases predicted *EI* is within 5 % of that observed. Therefore, these data indicate the method predicts Bay Area refinery *EI* well.

Table 1. Observed and predicted northern California refining data, 2014.

–––––––Data inputs analyzed to estimate (predict) refinery energy intensity–––––––

Crude feed quality		Capacity utilization	Products ratio (Pratio)
Density *(d)*	Sulfur content *(S)*		
891.71 kg/m^3	11.70 kg/m^3	97.7 %	3.871
Based on 55% foreign, 34.7% Californian, and 10.3% ANS (<1% other) N. Calif. crude feed in 2014;[14] and respective foreign,[15] Calif.,[12] ANS[12] crude densities of 869.66, 932.70, 871.40 kg/m^3 and sulfur contents 14.39, 8.03, 9.67 kg/m^3.		From 2014 N. Calif. crude feed and capacity[13, 16] of 46.48 and 47.58 MM m^3.	Ratio of gasoline, diesel, kerosene, naphtha to other products; Calif. avg. from 2004–2009.[12]
Sensitivity case (SC) inputs for possible variability in N. Calif. refinery products ratio (+/– 20 %):		SC – 20 %	3.097
		SC + 20 %	4.645

–––––––Actual (observed) and estimated (predicted) refinery energy intensity–––––––

Observed energy intensity (*EI*)	Predicted energy intensity (*EI*)		
(GJ/m^3)		(GJ/m^3)	(Δ from observed)
4.874	Prediction	4.950	+ 1.56 %
	SC – 20 %	5.073	+ 4.08 %
	SC + 20%	4.827	– 0.96 %
From reported emissions of 347.3 kg/m^3 crude run by N. Calif. refineries in 2014,[13, 17] and Calif. average refinery fuel mix emission intensity during 2004–2009 (71.25 kg/GJ).[12]	Estimated from data inputs above in the prediction mode of the 2010 method.[11] SC +20% and –20% data: sensitivity analysis cases above. See Appendix A for details.		

Data from California Energy Commission,[13–14] U.S. Energy Information Administration,[15–16] Union of Concerned Scientists,[12] and California Air Resources Board.[17] Predictions by 2010 estimation method.[11] *See* end notes for full references. Data shown include the Nipomo facility of the San Francisco refinery.

Potential Changes in Bay Area Refinery Crude Feed Quality

A major change in Bay Area and California refinery crude feeds is underway and nearly certain to continue. During 1985–1988 California refiners received 95 % of their crude feed from California and Alaska.[26] Then total combined crude production in these states fell by 65 % from 1988–2014.[27–28] By 2014 these states accounted for only 48 % of statewide[26] and 45 % of Bay Area[14] crude feed. Government[29] and industry[36] analyses confidently predict that the geologic and market factors driving this terminal decline in West Coast oil resources and their replacement with new oil resources will keep driving California crude-feed switching. Further, reliance on these dwindling supplies for 45 % of its current feed shows Bay Area refining will continue to be affected by these factors.

Meanwhile, key differences in the delivery infrastructure for crude acquisition by Bay Area refiners also increase the likelihood of future crude switching here. California crude supplies are delivered to the Bay Area for refining via pipelines.[14] In contrast, the imported foreign oils that comprise 55 % of Bay Area refiners' current crude feed is delivered to them via marine vessels sailing from oil ports worldwide and, to a much lesser but potentially growing extent, via oil trains from the Canadian tar sands.[14] Thus, instead of being "hardwired" into specific crude fields connected to them by pipelines, Bay Area refiners are increasingly able to switch a major and growing portion of their crude feed by choosing among a wide variety of imported oils.

Their wide variety of choices for replacement crude allows Bay Area refiners to acquire, blend, and process future crude feeds that could be of better, similar, or lower quality than those they process now. Indeed, climate constraints—which limit the amounts of fossil fuels than can be burned without risking severe and irreversible societal and economic impacts—suggest that some 40 % of currently proven oil reserves cannot be used,[30] so there is no valid societal reason for using the dirtier-burning portion of the oil resource. In fact, from a societal standpoint, using much more of the so-called "extreme" oils such as tar sands oils does not make economic sense.[30]

However, crude acquisition can account for up to 90 % of refinery operating costs,[7] and price discounts on low quality oil can be substantial. On a barrel-for-barrel basis, from 2004–2015, annual discounts on denser crude (≤ 20 °API *v.* 35.1–40 °API) ranged from 8–28 % of West Coast refiners' crude acquisition costs, and discounts on Canadian Bow River Heavy versus Saudi Arabian Medium *averaged* 18.9 % of West Coast refiners' crude costs.[31–34] Refiners that are able to run bottom-of-the-barrel crude and externalize the associated pollution costs could boost profits on such cost savings. As of 2014 such low-quality (≤ 20 ° API) crude oils accounted for only about 3 % of Bay Area refinery crude imports,[15] however, both globally and regionally, the oil industry has announced plans to refine low quality oil here in much greater volume.

Crude Switch Plans

In 2007 a report in the *Oil & Gas Journal* described industry plans to expand the market for price-discounted oil produced in the Canadian tar sands by, among other things, sending large amounts of it to California refineries as a new potential growth market.[35] By 2009 a paper published by the Society of Petroleum Engineers explained this from a refiner's standpoint, concluding that the Canadian tar sands is "the most promising source for California refineries" to replace dwindling current crude supplies in the long term.[36]

A 2013 Alberta Energy Resources Conservation Board report described projects to send tar sands oil to California if the state's standards allow the resultant emissions, suggesting "90 percent of its refinery capacity" might be "able to process heavier crudes."[37] The same year Valero reported to investors on its "strategy" to refine "cost-advantaged crude oil" and its plan to bring that oil to its Benicia refinery by train.[38] Valero's 2013 report includes a chart showing that Western Canadian Select, a tar sands-derived crude stream, is the most price-discounted crude oil targeted, costing much less than fracked shale oil from the Bakken formations to the south of the Canadian tar sands in the U.S.[38]

A 2013 report to investors by Phillips 66 stated its plans for "moving Canadian crudes down into California … refineries."[39] A 2014 report to investors by Phillips 66 stated its plans to bring this "advantaged crude into California" by train and ship via Ferndale, WA and by train to the Nipomo facility of its San Francisco Refinery (SFR).[40] That project that would bring tar sands oil through the Bay Area via rail for refining at the SFR's Nipomo and Rodeo facilities. A map posted on a Phillips 66 website in 2015 showed crude oil delivery arrows pointing from the Canadian tar sands region to the SFR.[41]

In 2014 Tesoro reported to investors on its projects to "strengthen refinery conversion capability" for "feedstock flexibility."[42] Tesoro also reported greater future production in the Canadian tar sands than any other "key Tesoro market," and that its rail-to-marine terminal project in Vancouver, Oregon would be "competitive with direct rail cost to California."[42]

In 2015, the Canadian Association of Petroleum Producers (CAPP) reported an update on plans to greatly increase tar sands oil exports to California refineries.[43] This CAPP report updated details of its plans to export increasing production of those bitumen-derived oils to the West Coast, including California, via pipeline, boat, and train.[43]

Also in 2015, a report by CBE and ForestEthics[44] identified oil train projects statewide that, collectively, could replace up to 40–50 % of the current statewide California refinery crude feed via new and expanded rail delivery facilities alone.

Crude Switch Projects

Plans for the oil industry's regional crude switch are being implemented piecemeal through site-specific projects. Proposed by various oil companies to build new or expanded capacity for oil delivery, storage, and processing at existing or proposed facilities, these pieces of the larger regional infrastructure project could collectively enable the regional oil feed switch. Parts of this infrastructure have been implemented despite incomplete safeguards against oil switching impacts.[45] These parts include a Richmond refinery heavy gas oil processing expansion, and much the 40 million barrels/year of new heavy oil cracking capacity Bay Area refiners built since 1990.[6] Other parts of the planned infrastructure have not yet been fully implemented: At least 16 northern California oil infrastructure projects that could enable the industry's plans to refine lower quality oil in the Bay Area have been proposed in recent years.

In 2011 the Chevron Richmond refinery proposed a project to further expand its cracking and hydroprocessing capacity for refining heavy gas oil and greatly expand its hydrogen production capacity.[46] Not yet fully implemented, this project was approved with conditions in 2014[46] after a larger project that could have enabled a full-blown switch to refining lower quality crude and gas oils was blocked by state courts in 2009 and 2010 for failure to disclose and address crude switching impacts.[47]

Although the Richmond refinery has existing capacity to acquire all of its oil feed via tanker and barge, Kinder Morgan proposed an oil train-unloading terminal adjacent to the Richmond refinery in 2013. The Air District approved this project in 2014 without adequate public notice and despite the resultant public health hazards.[48] This project expanded the capacity of Bay Area refineries to process tar sands oils and fracked shale oils delivered by "unit" trains dedicated to oil transport, however, a condition of Chevron's 2014 project approval that was adopted by the City of Richmond prohibits Chevron from processing oil delivered by Kinder Morgan Richmond oil train terminal.[46]

In addition to its 2009–2010 heavy gas oil hydrocracking and hydrogen plant expansion[6] discussed above the Phillips 66 San Francisco Refinery (SFR) proposed at least five other interrelated infrastructure expansions. Since 2012 the company proposed a throughput expansion and oil train unloading spur at the SFR's Nipomo facility, a light ends debottlenecking "LPG project" at its Rodeo facility, and three expansions of wharf capacity enabling increased oil imports at its Rodeo facility.[49-50] The interrelated infrastructure expansions proposed could enable the refinery to switch the vast majority of its crude feed to bitumen-derived and fracked oils.[49-50]

During 2015–2016 NuStar Shore Terminals proposed switching over a major portion of its rail-linked ethanol storage and transfer facility at Rodeo to crude service.[51] This proposed oil storage and transfer project would be linked by pipeline to the adjacent Phillips 66 Rodeo refining facility, and could serve other Bay Area refineries as well. It was proposed after WesPac withdrew a proposal for a massive new rail- ship- and pipeline-linked oil storage and transfer facility in Pittsburg that could have served any or all the Bay Area refineries.[52–53]

The Shell Martinez refinery proposed a crude oil storage and wharf capacity expansion that could enable it to acquire larger amounts of low quality imported oil in 2011[54] and, in 2014, proposed a major refinery reconfiguration project.[55] This project appears, based on preliminary information, to enable refining lighter, better quality crude feeds,[55] but the project and its public review have been delayed since 2014[56] for unknown reasons.

In 2009 Praxair proposed a hydrogen pipeline between the Chevron Richmond, Phillips 66 Rodeo, and Shell Martinez refineries that would have supported expanded refining of lower quality oils by supplying more hydrogen for the processing of denser, hydrogen-poor oils.[57] This project was delayed by the company and Contra Costa County review of it lapsed in 2014. Whether this project will be re-proposed is unknown at this time.

Tesoro has proposed a major wharf expansion that could enable its “Golden Eagle” refinery at Avon (near Martinez) to acquire and process lower quality imported tar sands and fracked shale oils in greater amounts.[58] The approval of environmental review for this project by the State Lands Commission has been challenged is still under review in the state courts as of November 2016.

Valero has proposed an oil train unloading project at its Benicia refinery that would enable the refinery to acquire and process up to 70,000 barrels/day of Canadian tar sands oil, an amount equivalent to 45–50 % of its current crude feed, via the proposed new rail infrastructure alone.[59] This project was rejected by Benicia’s Planning Commission, then City Council, in 2016. Whether Valero will appeal this decision remains unknown.

Many of these projects were undisclosed or obscured at first: this list may be incomplete.

Tar Sands Oil Potential

"Tar sands oil" as this term is used herein includes "heavy oil" and "natural bitumen" as defined by the U.S. Geological Survey (USGS).[60] The USGS reports average densities of 957 and 1,030 kg/m^3 and average sulfur contents of 27.8 and 45.5 kg/m^3 for heavy oil and natural bitumen, respectively.[60] Even the low end of this range is much denser and more contaminated than the average Bay Area refinery crude feed in 2014 (892 kg/m^3 density; 11.7 kg/m^3 sulfur).[12, 14, 15] Each of at least 23 geologic basins in at least 16 countries in north and south America, Africa, and north, central, south and southeast Asia holds at least 14.7 billion barrels of these tar sands oils,[60] which is enough to supply 100% of the current Bay Area crude feed[13] for 50 years or longer.

A chart from a California Energy Commission (CEC) analysis[29] that forecast future California crude feed replacement is reproduced as Chart 1. As the chart illustrates, the CEC has projected that ≈ 83 % of the total California refinery crude feed could be imported by 2030 in its "high case" forecast.[29] Note the CEC's "imports" definition:

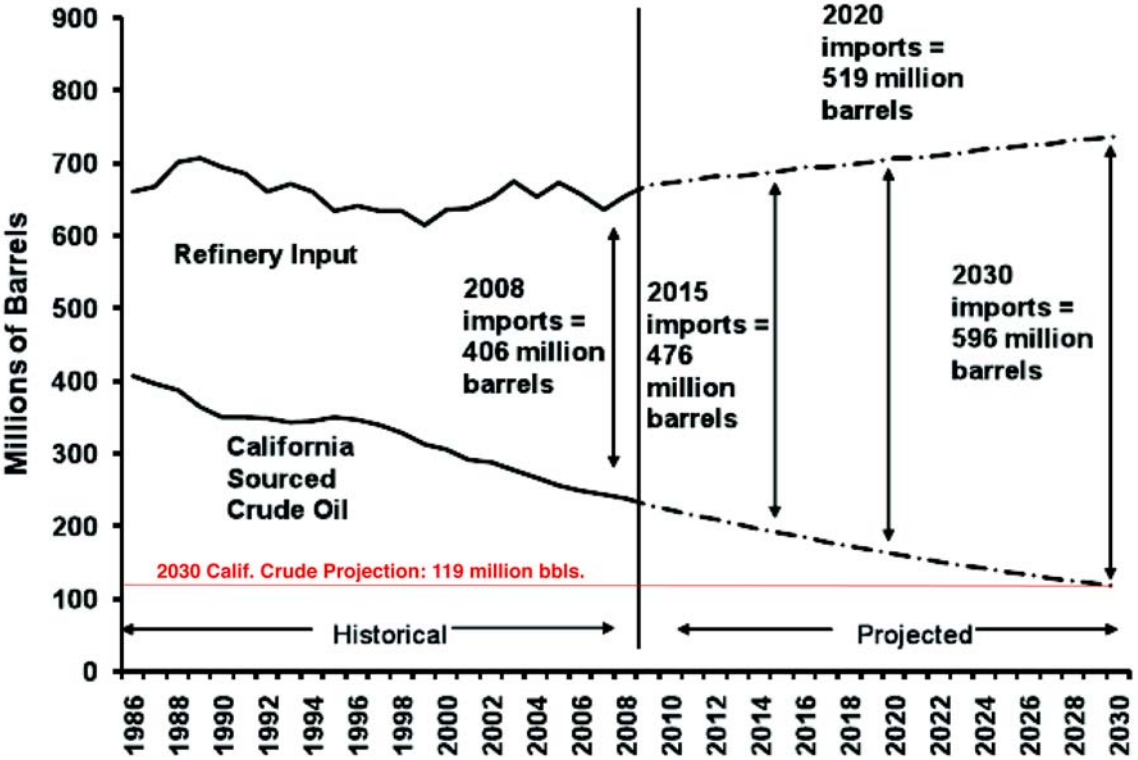

Chart 1. High Case Forecast for California Crude Oil Imports. Excerpted from California Energy Commission Transportation Energy Forecasts and Analysis (Figure 4.8).[29] California sourced oil projection scale in 2030 (red in chart) was added by CBE for reference.

Consistent with refiners' greater flexibility to switch away from current crude sources delivered via boat and train than those delivered via pipeline, this forecast distinguished California-sourced (pipeline) crude from the other sources of crude ("imports") refined. However, the CEC forecast excluded the environmentally relevant, if not crucial, period from 2030–2050, and in addition to continued California supply decline, the CEC "high case" also assumed future refinery production growth that may or may not occur. (*See* Chart 1.) Separating out that latter assumption, the CEC forecast a 3.2 %/year decline in California crude supply based on historic data in its "high case" (shown) and a 2.2 %/year decline in California supply based on recent years' data in its "low case" (not shown).[29]

Based on the 2.2–3.2 %/year decline in California pipeline crude the CEC forecast,[29] and the amount of this pipeline crude in the 2014 Bay Area crude feed (34.7 %),[14] the Bay Area feed could be 29–30 % pipeline crude (70–71 % "imports") by 2020 and 11–16 % pipeline crude (84–89 % "imports") by 2050. Thus, in oil switching scenarios consistent with the industry plans and infrastructure projects documented above,[31–59] tar sands oil could replace 50–80 % of the current Bay Area crude feed during 2020–2050. Table 2 summarizes data and forecasts for Bay Area crude feed quality in these scenarios.

Table 2. Potential Bay Area crude feed quality in tar sands scenarios, 2020–2050.

Low Case				
Oil source (access mode)	Current 2014 (mixed)	Heavy oil (import)	Bitumen (import)	The quality of the total crude feed is calculated as the sum of the oil sources' feed-weighted data:
Source density	891.71 kg/m^3	957.40 kg/m^3	1033.60 kg/m^3	
Source sulfur	11.70 kg/m^3	27.80 kg/m^3	45.50 kg/m^3	
Percentage of feed	50 %	50 %	0 %	
Feed-weighted density	445.86 kg/m^3	478.70 kg/m^3	—	
Feed-weighted sulfur	5.85 kg/m^3	13.90 kg/m^3	—	
	Low Case crude feed density:			**924.56 kg/m^3**
	Low Case crude feed sulfur content:			**19.75 kg/m^3**
High Case				
Oil source (access mode)	Current 2014 (mixed)	Heavy oil (import)	Bitumen (import)	The quality of the total crude feed is calculated as the sum of the oil sources' feed-weighted data:
Source density	891.71 kg/m^3	957.40 kg/m^3	1033.60 kg/m^3	
Source sulfur	11.70 kg/m^3	27.80 kg/m^3	45.50 kg/m^3	
Percentage of feed	20 %	40 %	40 %	
Feed-weighted density	178.34 kg/m^3	382.96 kg/m^3	413.44 kg/m^3	
Feed-weighted sulfur	2.34 kg/m^3	11.12 kg/m^3	18.20 kg/m^3	
	High Case crude feed density:			**974.74 kg/m^3**
	High Case crude feed sulfur content:			**31.66 kg/m^3**

Based on replacement of 50–80% of baseline 2014 crude feed from Table 1[12, 14, 15] by blends of 50–100% heavy oil with bitumen, and average heavy oil and natural bitumen density and sulfur reported by USGS.[60]

Shading in Table 2 denotes the crude feed calculation: In the low case current and heavy oil sources are each 50 % of total feed, so their "feed-weighted" densities are half their actual (source) densities; adding their feed-weighted densities yields crude feed density.

Both the amount of the current crude feed replaced, and the quality of the oil blends replacing it, affect Bay Area crude feed quality. Table 2 illustrates the combined effects: In the low case 50 % of the current crude feed is replaced by blends of heavy oils that are less dense and contaminated on average than bitumen, further limiting the change in feed quality relative to the high case, which includes additional new bitumen imports. In the high case, 80 % of the current crude feed is replaced by blends of 50% heavy oil and 50% bitumen, thus heavy oil and bitumen is each 40 % of the high case crude feed. In these tar sands scenarios the Bay Area refinery crude feed ranges from ≈ 925–975 kg/m^3 in density and ≈ 19.7–31.7 kg/m^3 in sulfur (2.14–3.25 wt. % sulfur) during 2020–2050.

The potential increase in crude feed density is substantial compared with the densities of Bay Area crude feeds processed in 2014 (≈ 892 kg/m^3)[12, 14, 15] and 2008 (≈ 900 kg/m^3),[11] and is extreme compared with the average U.S. crude feed density during 1999–2008 (≈ 873 kg/m^3).[11] However, refining technology that can process such oil blends exists. In fact, the density of the Shell Martinez refinery crude feed in 2008 (≈ 932 kg/m^3)[12] is within the range forecast here (925–975 kg/m^3).

The potential increase in Bay Area crude feed sulfur content also is substantial and on the same scale some refiners have designed for and processed. The sulfur content of the crude feed refined in Minnesota, Wisconsin, and North and South Dakota in April 1992 (3.16 wt. %),[61] and the design crude feed sulfur content of a project proposed but not built at the Chevron Richmond refinery (3.00 wt. %)[47] are within the range of this forecast (2.14–3.25 wt. %).

Accordingly—in addition to the need for crude source replacement, impetus for cheaper crude, its availability, and the industry's plans and projects that could continue to build for the crude switch forecast herein—the knowledge that some plants have processed roughly similar quality oils further supports the crude feed quality scenarios in Table 2.

Emissions Estimate for Bay Area Tar Sands Refining Scenarios

The direct emissions of air pollutants from oil refining that would be limited by proposed Rule 12-16 are causally, strongly, and positively related to refinery energy consumption.[†] Therefore, increases in these emissions that this rule could prevent may be estimated based on the energy consumed to refine potential lower quality 2020–2050 crude feeds.

These estimates used the peer reviewed method reported in 2010[11] because it is supported by nationwide data, estimated the energy intensity (*EI*) of this refining center well, and could predict *EI* based on publicly available, transparently verifiable, data. The formal method description is available free: http://pubs.acs.org/doi/abs/10.1021%2Fes1019965. Scenario-specific data inputs used in this application of the method were as follows.

- The density (*d*) of the potential crude feeds, in kg/m^3 crude, is the first of four data inputs to the prediction mode of the method. *d* is 924.56 kg/m^3 in the low case and 974.74 kg/m^3 in the high case. *See* pp. 14–16 and Table 2.
- The sulfur content (*S*) of the potential crude feeds, in kg/m^3 crude (the second data input): 19.75 kg/m^3 in the low case and 31.66 kg/m^3 in the high case. *Id*.
- Refinery capacity utilization (*CapUt*), the gross input to atmospheric crude distillation units divided by those units' operable capacity, in percent, is the third input: 90.3 % in both scenarios. This is the statewide average from 2004–2009.[12] This multi-year average spans years of high and low California engine fuels demand, and was used to more reliably forecast potential 2020–2050 operating conditions.
- Products ratio (*Pratio*), the volume of gasoline, kerosene, distillate, and naphtha divided by that of other refinery products (the fourth input): 3.871 in both scenarios; the statewide average[12] for the same period and reasons as for *CapUt.*

Descriptive data from refineries nationwide that support the predictions, and detailed results for *EI*, are given in Appendix B. *EI* predicted in the scenarios was compared with *EI* and emissions observed in 2014.[12, 13, 17, 62] 2014 is the most recent year when this method was shown to predict Bay Area *EI*. These comparisons are given in Table 3.

[†] At the points of emission from refineries, the $PM_{2.5}$ precursors NOx and SO_2 are oxidation products of combustion, condensable and filterable PM are combustion products (except for cooling tower PM emissions, which the proposed rule, in any case, would not limit) and CO_2e is ≈ 98.1–99.8% (100-yr GWP)[11] CO_2, a combustion product and, in the case of H_2 plants, emitted by consuming energy to strip H_2 from hydrocarbons in the steam reforming shift reaction.[11]

Table 3. Potential refinery energy and emission intensities of tar sands scenarios.

Results for Energy Intensity (EI)

	EI predicted by crude feed quality[a]			*EI* baseline[b]	Energy ratio (*ER*)
	Prediction (GJ/m^3)	95% confidence (GJ/m^3)	R^2	2014 observed (GJ/m^3)	Scenario : Baseline (ratio)
Low Case	6.802	+/– 0.446	0.90	4.874	1.40
High Case	9.719	+/– 0.654	0.90	4.874	1.99

Results for Emissions

—— Total N. Calif. refining crude feed vol. reported for 2014 (46,479,000 m^3)[c] held constant ——

	Energy Emissions	2014 (*ER* 1.00)[c]		Low Case (*ER* 1.40)		High Case (*ER* 1.99)	
		kg/m^3	tonnes/y	kg/m^3	tonnes/y	kg/m^3	tonnes/y
CO_2e	71.3 kg/GJ	347	16.1 MM	486	22 MM	690	32 MM
$PM_{2.5}$	4.47 kg/TJ	0.022	1,010	0.031	1,400	0.044	2,000
PM_{10}	4.78 kg/TJ	0.023	1,080	0.032	1,500	0.046	2,100
NOx	16.7 kg/TJ	0.081	3,780	0.113	5,300	0.161	7,500
SO_2	9.46 kg/TJ	0.046	2,140	0.064	3,000	0.091	4,200

(a) *EI* of Bay Area refining for crude feeds shown in Table 2 predicted by a peer reviewed method,[11] see Appendix B for details. (b) Bay Area refining *EI* observed in 2014 from Table 1. Energy ratios show that potential refinery *EI* is 1.40–1.99 times that observed. (c) Bay Area refining crude feed[13] and emissions[17, 62] observed in 2014. Energy emissions (emissions per unit refinery energy consumed) are based on observed *EI,* crude feed volume, and emissions in 2014. Potential (low and high case) emissions per m^3 crude refined are estimated from observed 2014 emissions per m^3 crude refined and *ER* data; potential mass emissions are estimated from these kg/m^3 emissions and crude feed volume.

As stated, the range of potential worst-case 2020–2050 Bay Area tar sands scenarios is bounded by a "low case" (50 % more heavy oil; 925 kg/m^3 *d,* 19.7 kg/m^3 *S* crude feed) and a "high case" (80 % more heavy oil/bitumen; 975 kg/m^3 *d,* 31.7 kg/m^3 *S* crude feed). Review of Table 3 reveals very large energy and emission impacts from refining lower quality oil in these scenarios. Refinery energy intensity predicted by the lower quality crude feed is ≈ 1.40–1.99 times the current level (see energy ratio results), and drives production-weighted (kg/m^3 crude) increases of 39–100 % in CO_2e, $PM_{2.5}$, PM_{10}, NOx, and SO_2 emissions from the Bay Area refining industry. See kg/m^3 results in Table 3.

Emitting more per barrel to refine low quality oil could greatly increase regional mass emissions. At current feed volume total annual emissions from Bay Area refiners could increase by approximately 5.9–16 million tonnes of CO_2e, 390–990 tonnes of $PM_{2.5}$, 420–1,020 tonnes of PM_{10}, 1,520–3,720 tonnes of NOx, and 860–2,060 tonnes of SO_2. See tonnes/year results in Table 3.

Discussion

Abundant evidence documents the need for the crude switch that Bay Area refiners already have begun, their impetus, plans and projects for switching to lower priced, lower quality oils, the ability to estimate energy-related emission impacts of this planned crude switch, and its severe potential impacts. In the plausible worst case, switching 50–80 % of the Bay Area refining industry's crude feed to blends of heavy oil and bitumen could increase the industry's particulate and greenhouse gas air pollution by ≈ 39–100 %.

The method used in this estimate has predicted oil quality-driven energy and emission increments from the Bay Area refining industry within 5 %. The oil quality-driven energy and emission increments that the method predicts in this estimate exceed this +/– 5 % power of prediction for the Bay Area industry by ≈ 6.8–19 times.

Other estimates and observations further support this estimate. In 2015 Gordon et al.[21] estimated CO_2e emissions from refining six crude oil streams (≈ 500–630 kg/m^3) that fall within those estimated here (486–690 kg/m^3). $PM_{2.5}$ emissions from the Chevron Richmond and Shell Martinez refineries in 2014 (0.028–0.046 kg/m^3 as compared with crude capacity)[16, 62] approach or exceed those in this estimate (0.031–0.044 kg/m^3). CO_2e emissions from the Shell Martinez refinery reported for 2008 (≈ 497 kg/m^3)[12] exceed the low case emissions in this estimate (486 kg/m^3). Finally, the tenfold increase in oil quality-driven refinery discharges of selenium reported in 2004[4] far exceeds the doubling of emissions reported for this estimate's high case.

The potential switch to tar sands oil would be incremental. Much of the infrastructure that would enable the switch to 50 % heavy oil in the low case has been proposed or built from 1995–2016, and Chevron replaced half of its Richmond refinery's crude feed in five years, after expanding its FCC unit.[1, 6, 15, 46–59] Further, if heavy oil/bitumen blends were to replace the lighter current imports in the Bay Area refinery crude feed instead of its relatively denser California pipeline supply, the density of the crude feed and emissions from refining it could increase more rapidly. The low case emissions thus could occur early in the 2020–2050 forecast period. Meanwhile, the high case requires more oil infrastructure that takes more time to build, and Bay Area refineries may continue to build it piecemeal over decades, before the high case emissions could occur.

Data and forecasting limitations further inform the interpretation and use of this estimate:

Much of the pollution from refining lower quality oil that is asociated with Bay Area refineries is outside the scope of this estimate for direct emissions of energy-related pollutants. Examples include selenium and mercury contamination (see pp. 3–4)[4, 9, 10] and exports[63] of the dirty-burning coke byproduct from refining lower quality oil.[11] Future work should address these emissions.

Crude feed volume and "end-of-pipe" engineered controls affect refinery emissions, and the estimate holds those factors constant to better estimate oil quality-driven emissions. This supports addressing emissions related to the other factors in an important way: The estimate supports analysis of the potential for oil quality-driven emission increments to impede or foreclose the ability of other measures to achieve needed emission reductions.

Incomplete publicly reported data for many oil quality characteristics, plant-level product slates, and process-level inputs and outputs limit the reliability of this estimation method for predicting oil quality-driven emissions from individual refineries.[11–12, 18–22] This estimate of the *regional* refining industry's potential emissions should not be interpreted as an equally accurate prediction of potential emissions from individual plants.

Emissions could increase or decrease relative to this estimate if the mix of fuels refiners consume changes. Refiners' choices among hydrogen addition and carbon rejection technologies for converting denser oils to high-value products may change the emission intensity of the refinery fuel mix.[11] CO_2 emission impacts of changes in the refinery fuel mix have been shown to be small compared with those of oil quality-driven changes in energy intensity,[11, 12] however, the potential for changes in refinery fuels to affect other emissions should be addressed.[22] Increased by-production of gases from coking denser oils and bitumen may contaminate fuel gas that is burned refinery-wide, which might increase SO_2 and $PM_{2.5}$ emissions more than estimated here.[22]

Refiners could switch to better quality crude feeds than tar sands oil. This is feasible, less costly to society,[30] and would avoid the huge potential increase in climate and health threatening air pollution from refineries in the Bay Area that is forecast here. The emission limits proposed in Rule 12-16 would prevent this emissions increase and address this uncertainty.

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APPENDICES

A. Details of Predictions for Energy to Refine Lower Quality Oil, 2014.

B. Details of Predictions for Energy to Refine Lower Quality Oil, 2020–2050.

APPENDIX A. Details of Predictions for Energy to Refine Lower Quality Oil, 2014.

PADD	Year	*EI* (GJ/m^3)	*d* (kg/m^3)	*S* (kg/m^3)	*CapUt* (%)	*Pratio*
1	1999	3.451	858.20	8.24	90.9	3.668
1	2000	3.430	860.18	8.00	91.7	3.489
1	2001	3.518	866.34	7.71	87.2	3.479
1	2002	3.426	865.71	7.45	88.9	3.605
1	2003	3.364	863.44	7.43	92.7	3.321
1	2004	3.416	865.44	7.79	90.4	3.397
1	2005	3.404	863.38	7.17	93.1	3.756
1	2006	3.440	864.12	7.17	86.7	3.522
1	2007	3.499	864.33	7.26	85.6	3.443
1	2008	3.551	863.65	7.08	80.8	3.400
2	1999	3.368	858.25	10.64	93.3	4.077
2	2000	3.361	860.03	11.35	94.2	4.132
2	2001	3.396	861.33	11.37	93.9	4.313
2	2002	3.393	861.02	11.28	90.0	4.345
2	2003	3.298	862.80	11.65	91.6	4.281
2	2004	3.376	865.65	11.86	93.6	4.167
2	2005	3.496	865.65	11.95	92.9	4.207
2	2006	3.738	865.44	11.60	92.4	3.907
2	2007	3.800	864.07	11.84	90.1	4.161
2	2008	3.858	862.59	11.73	88.4	4.333
3	1999	4.546	869.00	12.86	94.7	3.120
3	2000	4.563	870.29	12.97	93.9	3.120
3	2001	4.348	874.43	14.34	94.8	3.128
3	2002	4.434	876.70	14.47	91.5	3.251
3	2003	4.381	874.48	14.43	93.6	3.160
3	2004	4.204	877.79	14.40	94.1	3.228
3	2005	4.205	878.01	14.40	88.3	3.316
3	2006	4.367	875.67	14.36	88.7	3.176
3	2007	4.226	876.98	14.47	88.7	3.205
3	2008	4.361	878.66	14.94	83.6	3.229
5	1999	4.908	894.61	11.09	87.1	2.952
5	2000	5.189	895.85	10.84	87.5	3.160
5	2001	5.039	893.76	10.99	89.1	3.231
5	2002	4.881	889.99	10.86	90.0	3.460
5	2003	4.885	889.10	10.94	91.3	3.487
5	2004	4.861	888.87	11.20	90.4	3.551
5	2005	4.774	888.99	11.38	91.7	3.700
5	2006	4.862	887.65	10.92	90.5	3.615
5	2007	5.091	885.54	11.07	87.6	3.551
5	2008	4.939	890.16	12.11	88.1	3.803
Data Inputs for Bay Area Refining in 2014						
Bay Area Refineries Actuals			891.71	11.70	97.7	3.871
Bay Area Refineries (SC – 20 %)			891.71	11.70	97.7	3.097
Bay Area Refineries (SC + 20 %)			891.71	11.70	97.7	4.645

Predictions for Energy Intensity (EI): Bay Area Refining in 2014

		95% Confidence Interval	
For EI (GJ/m^3)	Prediction	lower bound	upper bound
Bay Area Refineries Actuals	4.950	4.553	5.347
Bay Area Refineries (SC – 20 %)	5.073	4.703	5.443
Bay Area Refineries (SC + 20 %)	4.827	4.379	5.276

APPENDIX B. Details of Predictions for Energy to Refine Lower Quality Oil, 2020–2050.

Data Inputs from U.S. Refinery Observations

PADD	Year	*EI* (GJ/m^3)	*d* (kg/m^3)	*S* (kg/m^3)	*CapUt* (%)	*Pratio*
1	1999	3.451	858.20	8.24	90.9	3.668
1	2000	3.430	860.18	8.00	91.7	3.489
1	2001	3.518	866.34	7.71	87.2	3.479
1	2002	3.426	865.71	7.45	88.9	3.605
1	2003	3.364	863.44	7.43	92.7	3.321
1	2004	3.416	865.44	7.79	90.4	3.397
1	2005	3.404	863.38	7.17	93.1	3.756
1	2006	3.440	864.12	7.17	86.7	3.522
1	2007	3.499	864.33	7.26	85.6	3.443
1	2008	3.551	863.65	7.08	80.8	3.400
2	1999	3.368	858.25	10.64	93.3	4.077
2	2000	3.361	860.03	11.35	94.2	4.132
2	2001	3.396	861.33	11.37	93.9	4.313
2	2002	3.393	861.02	11.28	90.0	4.345
2	2003	3.298	862.80	11.65	91.6	4.281
2	2004	3.376	865.65	11.86	93.6	4.167
2	2005	3.496	865.65	11.95	92.9	4.207
2	2006	3.738	865.44	11.60	92.4	3.907
2	2007	3.800	864.07	11.84	90.1	4.161
2	2008	3.858	862.59	11.73	88.4	4.333
3	1999	4.546	869.00	12.86	94.7	3.120
3	2000	4.563	870.29	12.97	93.9	3.120
3	2001	4.348	874.43	14.34	94.8	3.128
3	2002	4.434	876.70	14.47	91.5	3.251
3	2003	4.381	874.48	14.43	93.6	3.160
3	2004	4.204	877.79	14.40	94.1	3.228
3	2005	4.205	878.01	14.40	88.3	3.316
3	2006	4.367	875.67	14.36	88.7	3.176
3	2007	4.226	876.98	14.47	88.7	3.205
3	2008	4.361	878.66	14.94	83.6	3.229
5	1999	4.908	894.61	11.09	87.1	2.952
5	2000	5.189	895.85	10.84	87.5	3.160
5	2001	5.039	893.76	10.99	89.1	3.231
5	2002	4.881	889.99	10.86	90.0	3.460
5	2003	4.885	889.10	10.94	91.3	3.487
5	2004	4.861	888.87	11.20	90.4	3.551
5	2005	4.774	888.99	11.38	91.7	3.700
5	2006	4.862	887.65	10.92	90.5	3.615
5	2007	5.091	885.54	11.07	87.6	3.551
5	2008	4.939	890.16	12.11	88.1	3.803
Data Inputs for Bay Area Refining 2020–2050 Scenarios						
Bay Area Refineries Low Case			924.56	19.75	90.3	3.871
Bay Area Refineries High Case			974.74	31.66	90.3	3.871

Predictions for Energy Intensity (EI): Bay Area Refining 2020–2050 Scenarios

		95% Confidence Interval	
For EI (GJ/m^3)	Prediction	lower bound	upper bound
Bay Area Refineries Low Case	6.802	6.356	7.248
Bay Area Refineries High Case	9.719	9.065	10.372

Bay Area Air Quality Management District
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VIA EMAIL
vdouglas@baaqmd.gov
Victor Douglas

December 2, 2016

RE: Comments on the Scope and Content of the Notice of Preparation and Initial Study for Regulation 12: Miscellaneous Standards of Performance, Rule 16: Petroleum Refining Facility-Wide Emissions Limits (Rule 12-16)

Dear Mr. Douglas,

The Notice of Preparation and Initial Study for Rule 12-16[1] ("NOP/IS") suffer from significant defects and omissions in violation of the California Environmental Quality Act ("CEQA"). In particular, the NOP/IS omit critical discussion of recently permitted or reasonably foreseeable Bay Area refinery expansion projects that provide those refineries with the ability to process more polluting and climate disrupting oil feedstock. As such, the NOP/IS fail to adequately capture the existing environmental setting, tainting any evaluation of Rule 12-16. The NOP/IS reach several faulty conclusions, particularly regarding how adoption of Rule 12-16 (hereafter also referenced as "Emission Caps") might complement or conflict with the Bay Area Air Quality Management District's ("Air District") existing regulations and the State's climate policies, in particular, AB197.

At the November 16 meeting of the Air District Board of Directors, the Board of Directors provided specific direction to staff to include all relevant factual information for the determination of whether any such conflicts exist, within the Draft Environmental Impact Report

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[1] Including the accompanying October 2016 Draft Staff Report ("Staff Report") which discusses several issues required for inclusion in the Draft Environmental Impact Report, as detailed throughout this comment.

for Rule 12-16 ("Draft EIR"). Adhering to the Board's direction may remedy any similar defects in the Draft EIR as detailed further below.

I. The Draft EIR Must Include Discussion of Potential Conflicts with State and Regional Plans and Policies

CEQA Guidelines §15125(d) provides that an EIR *shall* discuss any inconsistencies between the proposed project and applicable general plans and regional plans. The Guidelines specifically state that such regional plans include "the applicable air quality attainment or maintenance plan or State Implementation Plan." We emphasize that the Draft EIR must include such a discussion which, following Board direction, requires disclosure and analysis of the following.

(i) Consistency with the Clean Air Act

The Air District is designated nonattainment for the 2006 $PM_{2.5}$ National Ambient Air Quality Standards ("NAAQS"). Recently, in August 2016, the Environmental Protection Agency ("EPA") issued a final rule providing a limited approval and limited disapproval of revisions to Air District Regulation 2, Rules 1 and 2 ("2-1" and "2-2").[2] The EPA concluded that Air District Rules 2-1 and 2-2 would become the federally enforceable New Source Review ("NSR") program in the SIP for the Air District, subject to the Air District's obligation to correct the rule deficiencies listed in the Federal Register.[3] Notably, the EPA found that the Air District's NSR regulations did not meet federal standards: "emission reductions intended to be used as offsets for new major sources or major modifications are only creditable if they are reductions of actual emissions, not reductions in the [potential to emit] of a source."[4] The federal provisions at issue include Clean Air Act §§ 173(a) and (c), the same provisions that the Staff Report suggests conflict with adoption of Rule 12-16.

Pursuant to the CEQA Guidelines, the Draft EIR must discuss any potential conflict. The Staff Report claims that there is a "significant argument" that Emission Caps would conflict with these federal provisions, but does not support that assertion with any facts or data.[5]

At a minimum, the Draft EIR must disclose relevant facts necessary for the Board and public to determine whether any such conflict exists. Such data must include: the amount of pollutant offsets, for PM_{10}, $PM_{2.5}$, SO_x and NO_x, that the Air District has allowed historically and foreseeably could allow in the future; whether any such offsets were granted subject to Rules 2-1 and 2-2 when those rules were applied less stringently than federal standards; and if so, whether Emission Caps may actually complement, rather than conflict with, achievement of the NAAQS. This discussion must also include a similar analysis of outstanding offsets held by refiners for previously permitted new or modified sources. Part II of this comment also details other relevant factual information required to make such an adequate determination regarding this alleged conflict.

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[2] Federal EPA docket number EPA-R09-OAR-2015-0280, available at https://www.regulations.gov/document?D=EPA-R09-OAR-2015-0280-0020

[3] *Id.*

[4] *Id.*

[5] Staff Report at 17.

(ii) Consistency with the State's Climate Policies

We are pleased that during the November 14 Scoping meeting, Air District staff clarified that the Draft EIR would discuss and evaluate any potential conflicts between Emission Caps and the State's Climate policies. Those policies include: AB32 and its successor legislation SB32 and AB197.

California's recent adoption of SB32 codifies ambitious climate change goals requiring the state to reduce greenhouse gas emissions to 40% below 1990 levels by 2030.[6] The passage of SB32 (and its ambitious greenhouse gas reduction targets) was contingent on the enactment of companion legislation — AB 197.[7] AB197 was introduced to provide greater legislative oversight in developing and adopting methodologies to reduce climate change pollution. This is significant because AB197 calls for specific measures that make the Air District's[8] promulgation of refinery greenhouse gas caps an essential component to achieving the state's more aggressive climate change pollution targets.

Importantly, SB32 paired with AB197 calls for a marked change in how California will achieve its more ambitious climate change pollution reduction goals. SB32 and AB197 require that the state "achieve the more stringent GHG emission reductions in a manner that benefits the state's most disadvantaged communities and is transparent and accountable to the public and the Legislature."[9] AB197 requires regulators to consider and address climate change and related pollution impacts on California's disadvantaged communities by considering the social costs of greenhouse gas emissions and implementing equitable solutions to mitigate the problem.[10] For example, while some regions of the state can afford to put more Teslas on the road, other regions that are disproportionately burdened by greenhouse gas and toxic polluting industries cannot. AB197 addresses this problem head-on by requiring regulators to prioritize the implementation of regulations that result in <u>direct emissions reduction at large stationary sources</u> in order to protect the state's most impacted and disadvantaged communities.[11] In other words, the Legislature expressly conditioned passage of SB32 on adoption of companion legislation—AB 197—that favors "command-and-control" regulation over market-based and incentive programs for large stationary sources like refineries when necessary to cause actual emission reductions in disadvantaged communities.[12] The bill's analysis even acknowledges that direct regulation is necessary in such communities and must be prioritized to achieve statewide limits while mechanisms such as cap-and-trade may operate as backstops to achieve excess reductions.[13]

The Staff Report conveys concerns that a greenhouse gas emission cap on refineries would conflict with California's greenhouse gas cap-and-trade and the Air District's own criteria

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[6] Senate Bill No. 32: Global Warming Solutions Act of 2006: emissions limit (extends AB 32 and sets 2030 greenhouse gas emissions targets), available at https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201520160SB32.

[7] SB32 specifies that "it shall become operative only if AB 197 is enacted…"

[8] Air districts have primary authority over regulation of stationary source air pollution.

[9] SB 32 Sec. 1 (d); *see also* AB 197 Sec. 1 (c), (e).

[10] AB 197 Sec. 5.

[11] *Id.*

[12] AB 197, Bill Analysis, Aug. 2016, available at http://www.leginfo.ca.gov/pub/15-16/bill/asm/ab_0151-0200/ab_197_cfa_20160824_113105_asm_floor.html.

[13] *Id.*

pollutant trading program. The report lacks any justification for this assertion. Also, the Staff Report states that the Board may not be able to justify the necessity of a greenhouse gas cap approach because other jurisdictions have not adopted one.[14] However, the Air District need not look to other jurisdictions for the authority to regulate greenhouse gas or other pollutant emissions.

The Staff Report also asserts that it would be difficult for the Air District to explain the benefit of capping greenhouse gas emissions because they are not localized health concerns.[15] However, data exists to the contrary. As one example, a recent University of Southern California study documents that local pollution from refineries has recently increased and underscores the potential health benefits of direct greenhouse gas reduction regulation.[16] The Staff's argument about localized health concerns is indeed a red herring. The momentum behind AB197's passage precisely counters this argument. AB197 explicitly acknowledges the need to consider the social, health and economic costs on disadvantaged communities as the basis for compelling direct regulation of greenhouse gas and local pollution specifically within the refinery sector.

The Staff Report is simply devoid of any discussion of the new regulatory landscape within which ARB and the Air District will be operating. It fails to mention SB32, AB197, its emphasis on equitable climate change solutions that protect California's disadvantaged communities, and its prioritization of direct emission reduction controls on the largest greenhouse gas polluting sources, in particular, the refinery sector.

Notwithstanding the Staff Report's omissions, the underlying purpose of AB197, that the state's climate change programs are not shared equally by all Californians, places an especially heavy burden on the Air District to address this problem. This is particularly true given that almost a third of the state's oil refineries are located in the Bay Area, and that the health and safety of Bay Area communities have long suffered disproportionately from the region's refinery pollution problems. Unfortunately, absent direct regulation of the refinery sector, the greenhouse gas and local pollution problems from refineries are only expected to worsen with the anticipated importation of more carbon intensive, low quality crudes such as Canadian tar sands.[17]

While ARB has primary authority over regulation of mobile sources of pollution, under the Federal Clean Air Act and state law, California's Air Districts have primary regulatory authority over stationary sources of air pollution.[18] Indeed, the enactment of SB32 and AB197 does not change this. Additionally, the courts have long affirmed air district authority to regulate

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[14] *Id.*at 17.

[15] *Id.* at 20.

[16] Cushing, L, Wander, M, Morello-Frosch, R, Pastor, M, Zhu, A, Sadd, J, "A Preliminary Environmental Equity Assessment of California's Cap-and-Trade Program," University of California, Berkeley, University of Southern California, San Francisco State University, Occidental College, Sept. 2016, available at http://cal.streetsblog.org/wp-content/uploads/sites/13/2016/09/Climate_Equity_Brief_CA_Cap_and_Trade_Sept2016_FINAL.pdf.

[17] "Next Frontier for Dangerous Tar Sands Cargo: California," Natural Resources Defense Council, Issue Brief, April 2015, at 2, available at https://www.nrdc.org/sites/default/files/west-coast-tar-sands-threat-ca-FS.pdf (tar sands process at California refineries could grow from 50,000 bpd to 650,000 bpd by 2040).

[18] *Ultramar, Inc. v. South Coast Air Quality Management Dist.* (1993) 17 Cal.App.4th 689, 708, citing *Western Oil & Gas Assn. v. Monterey Bay Unified Air Pollution Control Dist.* (1989) 49 Cal. 3d 408; *Orange County Air Pollution Control Dist. v. Public Util. Comm*. (1971) 4 Cal.3d 945, 948 (emphasis in original); Cal. Health and Safety Code § 40000.

air pollutants from large industrial stationary sources more stringently than the state and/or federal government, even pollutants not regulated by the state.[19]

CEQA requires the Draft EIR to evaluate Rule 12-16 in the context of SB32 and AB197, including how it complements these state policies and any potential inconsistencies. ARB will soon complete its Scoping Plan for implementation of SB32 targets, followed by promulgation of regulations to achieve those targets. As such, ARB's plan may be extremely relevant to the Draft EIR discussion. Moreover, that discussion must also include relevant factual information as discussed in the next section of this comment.

II. The Draft EIR Must Include Factual Information Relevant to Determine Potential Legal Conflicts

The following defects in the NOP/IS prejudice any adequate evaluation of Rule 12-16, particularly with regard to the potential conflicts noted above. Adherence to Board direction, and the CEQA Guidelines as noted below, could remedy these defects in the Draft EIR.

(i) The Draft EIR Must Include an Adequate Description of the Environmental Setting

CEQA Guidelines § 15125(c) provides that "[k]nowledge of the regional setting is critical to the assessment of environmental impacts [and] [s]pecial emphasis should be placed on environmental resources that are rare or unique to the region." The courts have affirmed this principle, holding that the absence of accurate and complete information regarding the project setting precludes the adequate investigation and discussion of the environmental impacts of the project.[20] The NOP/IS fail to outline the environmental setting in three significant respects: a current regional crude shift to a lower quality, and more polluting, oil feedstock; the disproportionate impact of such increased pollution on local low-income communities of color; and finally, how that impact is emphasized by the contrast of growing foreign exports of fuel and decreasing domestic consumption.

(a) The Draft EIR Must Include Recent and Proposed Bay Area Refinery Expansion Projects in its Discussion of the Environmental Setting

First, since at least 2012, the Air District has acknowledged the influx of lower quality oils into the Bay Area and admitted the occurrence of "increased emissions of air contaminants" and emission increases as a result of "accidents related to the increased corrosiveness of lower quality crudes."[21] The Air District has since permitted at least three refinery expansion projects that enable those refineries to process and refine lower quality crude oil feedstocks.[22] Other

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[19] *Western Oil & Gas Assn. v. Monterey Bay Unified Air Pollution Control Dist*. (1989) 49 Cal. 3d 408, 418; *Ultramar, Inc. v. South Coast Air Quality Management Dist*. (1993) 17 Cal.App.4th 689, 707.

[20] *San Joaquin Raptor/Wildlife Rescue Center v. County of Stanislaus* (1994) 27 Cal. App. 4th 713.

[21] BAAQMD Regulatory Concept Paper, Petroleum Refining Emissions Tracking Rule, Draft, October 15, 2012, citing The U.S. Oil Refining Industry: Background in Changing Markets and Fuel Policies" (Nov. 22, 2010), available at http://www.baaqmd.gov/~/media/files/planning-and-research/rules-and-regs/workshops/2013/1215_dr_rpt032113.pdf?la=en.

[22] In 2013, the Air District permitted the Kinder Morgan Richmond Terminal Crude by Rail Project; in 2014, the Chevron Richmond Refinery Modernization Project; in 2015, the Phillips 66 Rodeo Refinery Propane Recovery Project.

similar expansion projects in the Bay Area are currently proposed, such as the Nustar Shore Terminals LLC Selby Terminal Crude Oil Project.

Ample evidence[23] illustrates that these expansion projects allow each respective refinery to have the flexibility to refine a broader range of crude oil feedstocks. These are the very "update[s]" or "modif[ications]" the Staff Report notes are required to process "crude oil from different sources."[24] Those new and different sources include a greater quantity of cost-advantaged and extreme polluting and climate disrupting feedstocks, such as tar sands diluted bitumen.

Nevertheless, the NOP/IS diminish the impact of these refinery expansion projects throughout the Bay Area, making only brief and cursory references. To the contrary, pursuant to CEQA Guidelines § 15125(c), the Draft EIR description of the environmental setting must disclose each permitted, proposed, and foreseeable refinery infrastructure expansion—or "update"—and whether, and if so by how much, each expansion may allow the respective refinery to process a greater quantity of more climate disrupting and polluting crude oil feedstock.

(b) The Draft EIR Environmental Setting Must Include an Assessment of the Local and Disproportionate Impact of Refinery Pollution

As noted in the November 11, 2016 comment on the NOP/IS submitted by CBE and other organizations, there is abundant evidence that refinery emissions disproportionately impact nearby low-income communities of color. We have illustrated several examples, including elevated indoor $PM_{2.5}$ exposures in the homes of low-income residents of color in Richmond, increased exposure to ultra-fine PM from refinery sources, and elevated concentrations of emissions during episodic emissions from incidents such as the August 2012 Chevron Richmond Refinery fire.

The NOP/IS, however, suggests that there is no such local impact of refinery pollution. The Staff Report even suggests that $PM_{2.5}$ exposure is a regional, not a local, problem. The Staff Report arrives at its faulty conclusion by relying upon only regional, or ambient, air quality data. Indeed, the air monitors that account for such measurements are located in San Pablo, Concord, Vallejo, San Rafael, San Jose, East Oakland, Livermore, San Francisco, Napa and Gilroy—none of which are home to a Bay Area refinery. The Draft EIR must instead include an adequate assessment of the local impact of refinery pollution, and in particular, on low-income communities of color that have historically faced such a disproportionate burden.

In assessing this local impact, it is also imperative to consider the cumulative impact of increased pollution on these already overburdened communities. Additionally, in so doing, the current environmental setting should also include data and documented vulnerability factors for these communities from existing mapping tools, such as CalEnviroScreen version 2.0.

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[23] *See* prior comments submitted by CBE on 10/21/15, 11/23/15 and 6/10/16.

[24] Staff Report at 8.

(c) The Draft EIR Environmental Setting Must Include Discussion of the Trend Toward Increased Exports from Bay Area Refineries

The NOP/IS states that "the Air District does not have the authority to *directly* address concerns about … the final destination of refined products."[25] However, much like the Air District's inability to directly regulate hazards at refineries balanced by its ability to address such concerns through regulating resulting episodic spikes in emissions,[26] the Draft EIR must also discuss recent increasing exports from Bay Area refineries. These facts are directly relevant to and will inform any environmental and economic analysis of Rule 12-16.

As noted in our prior comments, adoption of Emission Caps would not significantly limit Bay Area refiners' production, which is currently at approximately 97.7% of capacity. Data also show that Bay Area refineries are producing more gasoline and diesel products than necessary to satisfy local demand, as well as an increasing trend to export such products to foreign countries.[27] Whether or not the Air District can directly regulate this practice that over-burdens low-income communities of color in our State, with no net benefit to the State, the Draft EIR must still discuss this increasing trend. Such a discussion is relevant to analysis of environmental impacts as well as any socio-economic analysis and must be included in the current environmental setting.

Moreover, the Staff Report asserts that adoption of Emission Caps may create similar economic impacts as the temporary closure of the ExxonMobil Torrance Refinery in 2015. The Staff Report does so without detailing any supporting data; instead, the Draft EIR must address the current production capacities of the Bay Area refineries in the environmental setting, the destination of those products, and whether such an assertion of similar economic impact is even plausible in the context of Rule 12-16. This disclosure is necessary to dispel any superficial arguments of "leakage," and for an evaluation of any perceived conflicts between Emission Caps and cap-and-trade and other related provisions of AB 32.

Similarly, the Staff Report has prematurely determined that Rule 12-16 may have significant economic impacts in the event that either refineries choose to make improvements and increase production above current capacity, or demand for gasoline or diesel products increases in California.[28] Those determinations, however, may be properly made only following an adequate description of the environmental setting as noted above.

Accordingly, the environmental setting must also note all measures that the Air District has already established to decrease refinery-wide pollution by approximately 15%. Specifically, the Draft EIR must address how refinery emissions may increase beyond the Emission Caps given that already-required 15% reduction, and under what current or future foreseeable refinery modification scenarios, such as a switch to a more polluting crude oil feedstock, Emission Caps could cause the need for expensive pollution control equipment.

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[25] Staff Report at 24 (emphasis added).

[26] *See supra*, BAAQMD Regulatory Concept Paper, October 2012.

[27] *See* prior comments submitted by CBE on 10/21/15, 11/23/15 and 6/10/16.

[28] Staff Report at 25.

(ii) The Draft EIR Must Include an Adequate Discussion of Foreseeable Changes to the Environmental Setting in its Discussion of the No Project Alternative

The CEQA Guidelines have explicitly rejected the notion that the ”no project” alternative may simply reflect current conditions as assessed in an EIR’s environmental setting, or even maintenance of such status quo. Rather, CEQA Guidelines § 15126.6(e) provides that a “no project” alternative must address “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.” Further, the Guidelines continue to elaborate upon how the “no project” alternative should proceed in this specific instance:

> When the project is the revision of … a regulatory plan, policy or ongoing operation, the “no project” alternative will be the continuation of the existing plan, policy or operation into the future … the projected impacts of the proposed plan or alternative plans would be compared to the impacts that would occur under the existing plan.[29]

Therefore, the Draft EIR “no project” alternative must not only outline foreseeable changes to the environmental setting, but also evaluate how the Air District’s current regulations, without Rule 12-16, could protect public health given those changes, particularly with regard to any disproportionate impact on low-income communities of color. This requires full disclosure and evaluation of the foreseeable climate and local pollution impacts that could result from the several Bay Area refinery expansion projects that enable the refining of lower quality oil feedstocks, and also, how the Air District’s regulations with and without Rule 12-16 can reduce such impacts. Necessarily, this also requires a discussion of the “infrastructure inertia” created by the commitment to major capital refinery investments in process changes to enable more refining of more climate-disrupting feedstocks for the foreseeable future. The “no project” alternative also should discuss potential conflicts between these projects and the State’s climate policies, including an analysis of the opportunity cost of a sustainable energy future.

Finally, the NOP/IS apparently creates a false choice between Rules 12-16 and 11-18. Whilst Rule 11-18 targets various toxic air contaminants, it does not target, as Rule 12-16 does, GHGs and $PM_{2.5}$. Moreover, the number of sources potentially affected by Rule 11-18 stands in stark contrast to the few affected by Rule 12-16. Each rule considers a significantly different range and source of pollutants. In fact, CEQA requires that an alternative “feasibly accomplish most of the basic objectives” of the proposed project.[30] Aside from the clear public health benefits of both rules, it is hard to imagine a single basic objective common to both Rules 12-16 and 11-18. We have consistently requested Air District staff to sever environmental review of the two proposals, but at a minimum, consideration of one as an alternative to the other simply does not make sense and violates CEQA.

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[29] CEQA Guidelines § 15126.6(e)(2)(3)(A).
[30] CEQA Guidelines § 15126.6(c).

III. Conclusion

The NOP/IS mischaracterize or omit information relevant to the determination of how Rule 12-16 complements the requirements of the Clean Air Act and the State's climate policies. Adherence to the Air District Board's November 16 direction, and the CEQA Guidelines as noted above, may remedy these errors in the Draft EIR for Rule 12-16.

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CHAPTER 5

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5.1 REFERENCES

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5.2 ORGANIZATIONS AND PERSONS CONSULTED

The CEQA statues and Guidelines require that organizations and persons consulted be provided in the EIR. The following organizations and persons have provided input into this document.

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CHAPTER 4

ALTERNATIVE ANALYSES

Discussion of Alternatives
Description of The Project Alternatives
Environmental Impacts of Project Alternatives
Environmentally Superior Alternative
Comparison of Alternatives

4.0 ALTERNATIVES ANALYSIS

4.1 DISCUSSION OF ALTERNATIVES

An EIR is required to describe a reasonable range of feasible alternatives to the proposed project that could feasibly attain most of the basic project objectives and would avoid or substantially lessen any of the significant environmental impacts of the proposed project (CEQA Guidelines §15126.6(a)). As discussed in Chapter 3 of this EIR the proposed project could result in potentially significant impacts to air quality~~, and GHG emissions,~~ during construction and hydrology (water demand) during project operation. Therefore, alternatives analysis should focus on alternatives that avoid or minimize these potentially significant impacts.

~~The objectives of proposed Rule 11-18: Toxic Risk Reduction are as follows:~~

1) ~~Reduce the public's exposure to health risks associated with the emissions of TACs from stationary sources to the lowest levels achievable;~~
2) ~~Incorporate the most up-to-date health risk methodologies and health values into the Air District's risk evaluation process for existing stationary sources of TACs;~~
3) ~~Ensure the facilities that impact the most sensitive and overburdened communities reduce their associated health risk in an efficient and expeditious manner;~~
4) ~~Provide the public opportunity to comment on the draft HRAs to provide transparency and clarity to the process; and~~
5) ~~Provide the public opportunity to comment on risk reduction plans as they are drafted by the affected facilities.~~

The objectives of proposed Rule 12-16: Refining Emission Limits are to:

1) Protect air quality, public health, and the climate from increases in annual facility-wide mass emissions of GHGs, PM, NOx, and SO_2 caused by changes in refinery oil feed quality or quantity, refinery or support equipment or operation, or combinations of these causes, by preventing any significant increase in these emissions;
2) Protect the climate and public health by preventing any significant increase in these emissions at refineries and associated facilities from increasing the emission intensity of the production of transportation fuels;
3) Protect community and public health by preventing any significant increase in these emissions from worsening hazards for which HRA methods may not account, including but not limited to acute and chronic ambient PM, NOx, SO_2, and PM exposure hazards; and
4) Complement other air quality, public health, and climate measures by discouraging investment in new refinery equipment that would lead to increased emissions of GHG, PM, NOx, or SO_2 from Bay Area refineries.

Chapter 4 provides a discussion of alternatives to the proposed project as required by CEQA. According to the CEQA guidelines, alternatives should include feasible measures to attain the basic objectives of the proposed project and provide means for evaluating the comparative merits of each alternative. In addition, though the range of alternatives must be sufficient to permit a reasoned choice, they need not include every conceivable project alternative (CEQA Guidelines,

§15126.6(a)). The key issue is whether the selection and discussion of alternatives fosters informed decision making and public participation.

In accordance with CEQA Guidelines §15126.6(c), a CEQA document should identify any alternatives that were considered by the lead agency, but were rejected as infeasible during the scoping process and briefly explain the reason underlying the lead agency’s determination. Section 15126.6(c) also states that among the factors that may be used to eliminate alternatives from detailed consideration in an EIR are: (1) failure to meet most of the basic project objectives; (2) infeasibility; or (3) inability to avoid significant environmental impacts.

The possible alternatives to the ~~two~~ proposed rule~~s are~~ is limited by the nature of the project. ~~The proposed Risk Reduction Rule is designed to minimize health risks associated with facilities that emit TAC emissions through the approval and implementation of risk reduction plans or the application of the best available retrofit control technology for toxics (TBARCT) to significant sources of toxic emissions. If the Air District fails to adopt this rule, portions of the rule could be implemented under other requirements, e.g., the AB 2588 Air Toxics “Hot Spots” Program.~~

The proposed Refining Emissions Limits Rule is intended to prevent significant increases in climate and criteria pollutants associated with combustion during refining operations. If the Air District fails to adopt this rule, portions of the rule could be implemented under draft Rule 13-1: Refinery Carbon Intensity and GHG Emissions Limits (if it were adopted) and other control measures contained in the draft 2017 Clean Air Plan.

This draft EIR will evaluate Project Alternatives for ~~both~~ Rule~~s 11-18 and~~ 12-16, including a “No Project Alternative” ~~for both~~ and additional alternatives deemed appropriate by Air District staff. ~~for evaluating the two rules.~~

~~4.2 DESCRIPTION OF THE PROJECT ALTERNATIVES: RULE 11-18~~

~~4.2.1 ALTERNATIVE 1.1 – NO PROJECT ALTERNATIVE (11-18)~~

~~CEQA Guidelines §151216.6 (e) requires evaluation of a “No Project Alternative.” Under the No Project Alternative (11-18), the proposed rule would not be adopted and, thus, the Air District would not establish risk actions levels of 10/M for cancer health risk and 1.0 for both acute and chronic hazard indices. Although, portions of the rule could be implemented under the Air District’s AB 2588 – Air Toxics “Hot Spots” Program, such as incorporating the new OEHHA health risk assessment protocols and health risk values and conducting health risk screening analyses and health risk assessments. Facilities with a cancer health risk greater than 10/M or an acute or chronic hazard index greater than 1.0[1] would only have to notify all exposed persons of their exposure. Facilities with a cancer risk greater than 100/M or a hazard indices greater than 10 would have to both 1) notify exposed individuals, and 2) reduce the facility~~

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[1] Health risks of 10/M cancer and 1.0 hazard indices are current action levels for notification under the Air District’s AB 2588 Air Toxics “Hot Spots” Program.

~~health risk below the risk action level in accordance to the Air District AB 2588 Program, California Health and Safety Code, §§44300-44394.~~[2]

~~4.2.2 ALTERNATIVE 1.2 – SET RISK ACTION LEVEL AT 25/M CANCER AND 2.5 HAZARD INDICES~~

~~Under Alternative 1.2, the Air District would establish risk action levels at 25/M for cancer risk and 2.5 for hazard indices instead of 10/M and 1.0 respectively. Further, the significant risk level for the compliance alternative for the application of TBARCT would be set at 5/M for cancer and 0.5 hazard indices or removed.~~[3] ~~All other aspects of the proposed rule would remain in place, including the provisions for the two compliance options: developing a risk reduction plan or demonstrating that all significant sources of risk are controlled with TBARCT. Under this alternative, the scope of the project would be significantly reduced because the rule would not apply to those facilities with health risks that are less than 25/M for cancer or 2.5 for hazard indices. As a result, the number of facilities affected by the rule would be reduced by from approximately 1,000 to fewer than 100 – an order of magnitude reduction. Table 4.1 illustrates the change of number of affected facilities by facility type.~~

~~Table 4.1: Comparison of the Numbers of Affected Facilities by Type under Proposed Rule 11-18 and Alternative 1.2~~

~~Facility Type~~	~~Proposed Rule 11-18~~	~~Alternative 1.2 Rule 11-18~~
~~Automotive Coating~~	~~1~~	~~0~~
~~Cement / Recycling~~	~~1~~	~~1~~
~~Cement Manufacturing~~	~~1~~	~~1~~
~~Chemical Plant~~	~~4~~	~~4~~
~~Chrome Plating~~	~~1~~	~~0~~
~~Concrete~~	~~1~~	~~0~~
~~Crematorium~~	~~16~~	~~4~~
~~Diesel Engines (only)~~		
~~Data Center~~	~~30~~	~~0~~
~~Emergency Standby~~	~~568~~	~~0~~
~~Engines and Other Sources~~	~~178~~	~~24~~
~~GDF~~	~~128~~	~~7~~
~~Landfill~~	~~28~~	~~16~~
~~Landfill + Sewage Treatment~~	~~2~~	~~0~~
~~Loading / Tanks~~	~~2~~	~~0~~
~~Metal Melting / Foundry~~	~~4~~	~~3~~

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[2] Health risks of 100/M cancer and 10.0 hazard indices are the current action levels for risk reduction under AB 2588. It should be noted that Air District staff did not identify any facilities with a preliminary health risks greater than these action levels.

[3] Without the TBARCT compliance option, the rule would be, in effect, an implementation of the AB 2588 program with lower risk action levels.

~~Facility Type~~	~~Proposed Rule 11-18~~	~~Alternative 1.2 Rule 11-18~~
~~Miscellaneous Manufacturing~~	~~20~~	~~11~~
~~Other~~	~~136~~	~~0~~
~~Power Plant~~	~~17~~	~~10~~
~~Printing~~	~~1~~	~~0~~
~~Refinery~~	~~5~~	~~5~~
~~Research~~	~~2~~	~~0~~
~~Sewage Treatment~~	~~32~~	~~10~~
~~Soil Vapor Extraction~~	~~1~~	~~0~~
~~TOTALS~~	**~~1154~~**	**~~86~~**

~~As shown in Table 4.1, the requirements of the rule would still apply to major sources of risk, such as refineries, cement manufacturing, and waste water treatment facilities; however, the level to which those facilities must reduce their health risk would be 25/M instead of 10/M. Under this alternative, the number of individuals that remain exposed to elevated health risk levels posed by these facilities would be much greater than that under the proposal.~~

4.2 DESCRIPTION OF THE PROJECT ALTERNATIVES

4.2.1 ALTERNATIVE 2.1 – NO PROJECT ALTERNATIVE

Under the No Project Alternative (12-16), the proposed rule would not be adopted and, thus, facility-wide emissions limits on GHGs, PM (PM_{10} and $PM_{2.5}$), NOx, and SO_2 would not be established. Therefore, the control of these emissions would likely continue to be addressed by the Air District current suite of programs, rules, regulations and any future measures contained in the draft 2017 Clean Air Plan and the State statues affecting climate pollutants. These methods of control include:

- Air District Rules affecting emissions of PM, NOx, and SO_2 from refineries and associated facilities.
- Control measures in the 2010 CAP not yet adopted;
- Rules and rule amendments in the Refinery Strategy;
- Control measures in draft 2017 CAP (not too speculative), including Rule 13-1; and
- AB 32 Cap and Trade Program, SB 32 and AB 197

The primary differences between Rule 12-16 and the No Project Alternative (12-16) is that the collection of measures ~~listed~~ referenced above would not only prevent the increase of climate and combustion criteria pollutants, but would result in substantial decreases of these pollutants over time (the proposed~~al~~ Rule 12-16 does not require emissions reductions).

4.2.1.1 Air Quality – Criteria Pollutants

Under the No Project Alternative (12-16), there would be no facility-wide emissions limits on the criteria pollutants PM, NOx, and SO_2. However, these pollutants are already being addressed by myriad Air District efforts. While this collection of measures would serve to significantly reduce the emission of these pollutants, they cannot, however, guarantee that these emissions would not increase from these facilities due to production increases or modifications to operations that are made for production reasons (that are allowed under current permit conditions) or that are required by other federal, state of local regulation.

4.2.1.2 Health Impacts – Toxic Air Contaminants and Fine Particulates

TACs: The No Project Alternative (12-16) would do little to reduce the emissions of toxic air contaminants and, therefore, risk. However, the adopted amendments to Rule 8-18 will reduce emissions of VOCs from fugitive emissions from refineries, including VOCs that are also TACs, such as benzene and 1,3-butadiene.

Fine PM: Fine PM is particulate matter with an aerodynamic radius of 2.5 microns or less, or "$PM_{2.5}$"). The draft 2017 Clean Air Plan contain numerous control measures that would reduce both directly emitted PM and secondary formation of PM (which is primarily $PM_{2.5}$) from the emission of NOx and SO_2. These measures are listed in the Table 4.2-1 below.

TABLE 4.2-1

Particulate Matter Control Measures from the 2017 Clean Air Plan

Measure Number	Title	Pollutant(s) Addressed	Primary or Secondary PM
SS1	Fluid Catalytic Cracking in Refineries	PM	Primary
SS4	Refinery Flares	ROG, SO_2, PM	Both
SS5	Sulfur Recovery Units	SO_2	Secondary
SS6	Refinery Fuel Gas	SO_2	Secondary
SS7	Sulfuric Acid Plants	SO_2	Secondary
SS8	Coke Calcining	PM, SO_2	Both
SS9	Enhanced NSR Enforcement for Changes in Crude Slate	All Pollutants	Both
SS18	Basin-Wide Combustion Strategy	GHG, PM	Both
SS22	Stationary Gas Turbines	NOx	Secondary
SS31	General PM Emission Limitation	PM	Primary
SS32	Emergency Backup Generators	DPM, TAC	Primary
SS35	PM from Bulk Materials, including Coke and Coal	PM	Primary

4.2.1.3 Climate Protection – GHGs

Currently, there are only two control measures in the draft 2017 Clean Air Plan that would limit or reduce emissions of GHGs from refining operations: this proposed rule and SS12: Petroleum Refining Climate Impact Limits (draft Rule 13.1). Additionally, the AB 32 Cap-and-Trade program and SB 32 will not only limit GHG emissions from refining operation, they would require the reduction of these pollutants over time to meet the near-term, mid-term, and long-term GHG emissions reduction goals of the State's Climate Protection Program.

4.2.2 ALTERNATIVE 2.2 – IMPLEMENT RULES 11-18 AND 13-1

This alternative would consist of a combination of the environmental benefits and impacts of adopting and implementing draft Rule 11-18 and draft Rule 13-1. Under this alternative, Rule 11-18 would reduce refinery health risks due to the emissions of toxic air contaminants to the lowest achievable levels, greatly reducing the health risks experienced by communities from refinery toxic emissions. Under draft Rule 11-18, facilities that posed a health risk greater than the risk action levels of 10/M for cancer and 1.0 for hazard indices would have to either 1) reduce the facility health risk below the actions levels through the implementation of a risk reduction plan, or 2) demonstrate that all significant sources of risk at the facility are controlled with TBARCT.

4.2.2.1 Rule 13-1

Draft Rule 13-1 would ensure that refinery emission of GHGs are either limited to their current maximum capacity or are constrained by the refineries' carbon intensity based on their maximum capacity (also incorporating cost-saving energy efficiency measures). Draft Rule 13-1 would complement and serve as a backstop for State climate protection efforts, which are anticipated to require a 20 percent reduction in refinery GHG emissions by 2030. Draft Rule 13-1 would:

- Set a carbon intensity limit for each refinery consistent with current operations;
- Set a mass-based GHG emissions limit as an alternate compliance option;
- Provide incentives for new energy improvement projects; and
- Accommodate new regulatory requirements and Air District permits.

4.2.2.2 Rule 11-18

The rule would require facilities that pose a site-wide health risk in excess of the risk action level threshold of ten per million cancer risk or 1.0 hazard index for both chronic and acute risk to reduce that risk below the threshold through the implementation of a risk reduction plan approved by the Air District or demonstrate that all significant sources of toxic emissions are controlled TBARCT; a significant source of toxic emission is one that poses a health risk of 1.0/M cancer or 0.2 hazard index. The rule would be implemented in four phases based on either a facility's prioritization score or the toxic emissions source.

The Toxic Risk Reduction Rule would utilize the annual toxic emissions inventories reported to the Air District by sources that emit toxic compounds. From the toxic emissions inventory data, Air District would conduct a site-specific Health Risk Screening Analysis (HRSA). From these HRSAs, the Air District would determine each facility's prioritization score. The facility prioritization score or the toxic emissions source type would be used to determine which phase a facility would be placed. The rule would be implemented in four phases based on either a facility's prioritization score or the toxic emissions source type as illustrated in Table 4.2-2.

TABLE 4.2-2

Implementation Phases

Phase	**Criterion**	**HRAs**	**Risk Reduction Plans**	**Plan Implementation**
1	Cancer PS(1) > 250 or Non-cancer PS > 2.5	2017 – 2018	2018 – 2019	2019 – 2022
2	Cancer PS > 10 or Non-cancer PS > 1.0	2019 – 2021	2021 – 2022	2022 – 2025
3	Diesel IC Engines	2021 – 2013	2023 – 2024	2024 – 2027
4	Retail Gas Stations	2023 - 2024	2024 -2025	2025 - 2028

(1) PS = prioritization score

The Air District would conduct HRAs for facilities in accordance with the OEHHA HRA Guidelines and the CARB/CAPCOA Risk Management Guidelines that were updated in 2015. Rule 11-18 would affect facilities with health risk impacts that exceeded any of the risk action level thresholds of ten per million cancer risk or 1.0 hazard index for both chronic and acute risk. The Air District would notify facilities of their health risk score. A facility with a risk action level exceeding the threshold(s) would be required to reduce the risk below the threshold(s) by implementing a risk reduction plan within five years of plan approval, or demonstrate that all significant sources of toxic emissions are controlled by TBARCT within the same three-year period; a significant source of toxic emission is one that poses a health risk of 1.0 per million cancer or 0.2 hazard index.

The Toxic Risk Reduction Rule would address TAC emissions from existing stationary sources. TAC emissions from new and modified sources are addressed under Air District Regulation 2, Rule 5. For the purposes of this rule, TACs consists of the substances listed in Air District Regulation 2, Rule 5: New Source Review of Toxic Air Contaminants. Some of the key pollutants to be addressed under the Toxic Risk Reduction Rule include benzene, polycyclic aromatic hydrocarbons (PAHs), and diesel particulate matter (DPM).

The Toxic Risk Reduction Rule would apply to a wide variety of commercial, industrial, and municipal facilities located throughout the Bay Area, including data centers, petroleum refineries, chemical plants, wastewater treatment facilities, foundries, forges, landfill operations, hospitals, crematoria, gasoline dispensing facilities (i.e., gasoline stations), colleges and universities, military facilities and installations and airline operations. The Air District estimates that hundreds of facilities could be impacted by this rule. Table 4.2-3 shows the most likely types of facilities anticipated to be affected by Rule 11-18.

Table 4.2-3
Summary of Toxic Air Contaminant Emitting Facilities and Sources

Facility	Sources	Primary Risk Driver(s)
Refineries	Fugitive Emissions Stack Emissions Diesel Engines Cooling Towers Wastewater Treatment Operations	Benzene Diesel PM Formaldehyde 1,3-Butadiene Chromium VI Nickel
Data Centers	Stationary Diesel Engines	Diesel PM
Cement Manufacturing	Stack Emissions Fugitive Emissions	Chromium VI
Chemical Plants	Stack Emissions Fugitive Emissions	Formaldehyde Carbon Tetrachloride Sulfuric Acid Mist Diesel PM
Crematoria	Stack Emissions	Chromium VI Mercury
Landfills	Fugitive Emissions Diesel Engines Energy Plants	Vinyl Chloride Hydrogen Sulfide Benzene Acrylonitrile Diesel PM Formaldehyde
Foundries	Fugitive Emissions	Dioxin Manganese Lead Chromium VI Mercury Cadmium Nickel Arsenic PAHs Copper
Sewage Treatment Facilities	Fugitive Emission Stack Emissions	Diesel PM Hydrogen Sulfide Cadmium Mercury
Power Plants	Stack Emissions	Formaldehyde Ammonia Benzene Diesel PM
Gasoline Stations	Fugitive Emissions	Benzene Ethyl Benzene
Military Facilities	Diesel Engines	Diesel PM
Manufacturing	Diesel Engines	Diesel PM

4.2.2.3 Control Technologies that May Be Used to Comply with Regulation 11, Rule 18

Draft Rule 11-18 would require preparation of a risk reduction plan for those facilities that pose a health risk in excess of the proposed risk action levels, 10 per million cancer risk level or a 1.0 hazard index. If a facility is identified that exceeds the risk action levels the facility must either: implement an Air District-approved risk reduction plan that details how the facility would reduce its health risk below the risk action level in the specified timeframe or demonstrate to the Air District that all significant sources of risk are controlled with TBARCT.

To comply with the risk action levels for those affected facilities that are required to prepare a risk reduction plan, operators could reduce operations or install TBARCT equipment. Table 4.2-4 identifies the types of facilities affected by the draft rule, the primary sources of TAC emissions, and the most likely types of control technologies that would be used to reduce risk.

Table 4.2-4

Summary of Toxic Air Contaminant Control Equipment

Facility	Sources	Control Equipment
Refineries	Fugitive Emissions	Establish requirements for more frequent inspections, require replacement of non-repairable valves, flanges, pressure relief devices, etc. (similar to or more stringent than Rule 8-19)
	Stack Emissions	Baghouse with high efficiency filter, LoTOx^{TM} with WGS, UltraCat
	Diesel Engines	Require emission limits based on the most efficient DPF, DOC (similar to or more stringent than Rule 11-17)
	Cooling Towers	Tighten requirements in Rule 11-10 for more frequent inspections and shorten time-period to comply once leak is detected (similar to or more stringent than Rule 11-10[a])
	Wastewater Treatment Operations	Require high collection efficiency of the organic compound recovery system, shorten period between inspections of wastewater collection systems (similar to or more stringent than Rule 8-18)
Data Centers	Stationary Diesel Engines	Require emission limits based on the most efficient DPF, DOC (similar to or more stringent than Rule 11-17)
Cement Manufacturing	Stack Emissions	Require baghouses with high efficiency filters (similar to or more stringent than Rule 9-13)
	Fugitive Emissions	Require enclosed conveyors and storage piles, rumble grates, conveyor skirting, dust curtains, road paving, reducing traffic speed and volume (similar to or more stringent than Rule 9-13)
Chemical Plants	Stack Emissions	Wet gas scrubber
	Fugitive Emissions	Establish requirements for more frequent inspections, require replacement of non-repairable valves, flanges, pressure relief devices, etc. (similar to or more stringent than Rule 8-22), baghouse with high efficiency filter
Crematoria	Stack Emissions	Baghouse with high efficiency filter
Landfills	Fugitive Emissions	Gas collection and control systems under continuous operation and under negative pressure at all times, enclosed

Facility	**Sources**	**Control Equipment**
		thermal oxidizer with a destruction efficiency of 99%
	Diesel Engines	Require emission limits based on the most efficient DPF, DOC, (similar to or more stringent than Rule 11-17)
Foundries	Fugitive Emissions	Baghouse with high efficiency filter
Sewage Treatment Facilities	Fugitive Emission	Enclose piping, process units, settling basins, lift stations, etc.
	Stack Emissions	Steam stripping and air stripping off-gases vented to a control or collection device, such as a combustion device (thermal oxidizer) or gas-phase carbon adsorber. Wet gas scrubbers and afterburners to control heavy metals, acid gas.
Power Plants	Stack Emissions	Baghouse with high efficiency filter, LoTOx^{TM} with WGS, UltrCat
Gasoline Stations	Fugitive Emissions	Establish requirements such as removing exemptions on various equipment or operations (similar to, or more stringent than Rule 8-7
Military Facilities	Diesel Engines	Require emission limits based on the most efficient DPF, DOC, (similar to or more stringent than Rule 11-17)
Manufacturing	Diesel Engines	Require emission limits based on the most efficient DPF, DOC, (similar to or more stringent than Rule 11-17)

[a] Effective July 1, 2016, Rule 11-10 prohibited use of chromium chemicals in all cooling towers in the district.
DOC = diesel oxidation catalyst, DPF = diesel particulate filter

~~4.4 ENVIRONMENTAL IMPACTS OF PROJECT ALTERNATIVES TO RULE 11-18~~

~~4.4.1 ALTERNATIVE 1.1 – NO PROJECT ALTERNATIVE (11-18)~~

~~4.4.1.1 Air Quality~~

~~Under the No Project Alternative (1), the proposed rule would not be adopted and, thus, the Air District would not establish risk actions levels of 10/M for cancer health risk and 1.0 for both acute and chronic hazard indices. Therefore, construction activities associated with installation of additional air pollution control equipment would be avoided. The construction activities associated with large air pollution control equipment, e.g., WGS, are potentially significant and this impact would not occur under the No Project Alternative (11-18). The operational air quality impacts associated with the proposed project were determined potentially significant. These operational emissions would also be avoided under the No Project Alternative (11-18). The potential beneficial impacts of the proposed project associated with additional risk and toxic emission reductions would not be realized under the No Alternative (11-18). Since the risk impacts of the affected facilities have not yet been determined, the amounts of risk and toxic emissions reductions that would not be realized under the No Project Alternative (11-18) are unknown. However, because there would be no additional operational emissions associated with the No Project Alternative (11-18), these impacts would be less than significant.~~

~~4.4.1.2 GHG Emissions~~

~~Under the No Project Alternative (11-18), the proposed rule would not be adopted and, thus, the Air District would not establish risk actions levels of 10/M for cancer health risk and 1.0 for both acute and chronic hazard indices. As a result, construction and operational activities associated with installation of additional air pollution control equipment would be avoided. Therefore, the GHG emissions associated with the No Project Alternative (11-18) would be less than significant.~~

~~4.4.1.3 Hazards and Hazardous Materials~~

~~Under the No Project Alternative (11-18), the proposed rule would not be adopted and, thus, the Air District would not establish risk actions levels of 10/M for cancer health risk and 1.0 for both acute and chronic hazard indices. As a result, construction and operational activities associated with installation of additional air pollution control equipment would be eliminated. The hazards associated with the proposed project were determined to be potentially significant for the operations of baghouses and ESPs. Hazards impacts associated with the potential installation of this equipment were determined to be less than significant after mitigation.~~

~~Under the No Project Alternative (11-18), there would be no additional construction and operational activities and hazards and the additional use of hazardous materials associated with implementation of Rule 11-18 would be avoided. Therefore, hazards and hazardous materials impacts associated with the No Project Alternative (11-18) would be less than significant.~~

~~4.4.1.4 Hydrology and Water Quality~~

~~Under the No Project Alternative (11-18), the proposed rule would not be adopted and, thus, the Air District would not establish risk actions levels of 10/M for cancer health risk and 1.0 for both acute and chronic hazard indices. As a result, construction and operational activities associated with installation of additional air pollution control equipment would be eliminated. Under Rule 11-18, water demand impacts were determined to be potentially significant, as the use of WGSs would potentially require a significant amount of water to operate. However, for this project water quality impacts were determined to be less than significant and, therefore, these impacts would be less than significant for the No Project Alternative (12-16).~~

~~Under the No Project Alternative (11-18), there would be no additional construction and operational activities and the additional water use and wastewater discharged associated with implementation of Rule 11-18 would be avoided. Therefore, hydrology and water quality impacts associated with No Project Alternative (11-18) would be less than significant.~~

~~4.4.2 ALTERNATIVE 1.2 – RISK ACTION LEVEL SET AT 25/M CANCER AND 2.5 HAZARD INDICES~~

~~4.4.2.1 Air Quality~~

~~Under Alternative 1.2, the Air District would establish risk action levels at 25/M for cancer risk and 2.5 for hazard indices instead of 10/M and 1.0 respectively. Further, the significant risk level for the compliance alternative for the application of TBARCT would be set at 5/M and 0.5 for hazard indices. Thus, there would be far fewer facilities that would be required to reduce their risk through the implementation of risk reduction measures and also fewer sources of risk that would have to be reduced. Therefore, construction activities associated with the installation of additional air pollution control equipment or implementation of risk reduction measures (such as increasing a stack's height or relocating equipment) would be greatly diminished. The construction activities associated with large air pollution control equipment, e.g., wet gas scrubbers, are potentially significant and this impact would be greatly diminished under the Alternative 1.2.~~

~~The operational air quality impacts associated with the proposed project were determined to be less than significant and the operational emissions under Alternative 1.2 would be significantly less than that under the proposed project. A significant portion of the potential beneficial impacts of the proposed project associated with additional risk and emission reductions of TACs would also be eliminated under Alternative 1.2. Since the need for risk and emission reductions has yet to be determined, the amounts of risk and emissions reductions that would not occur under Alternative 1.2 are unknown. However, because the operational air quality impacts associated with Alternative 1.2 would be a fraction of that of the proposed project, the operational emissions associated with Alternative 1.2 would be less than significant.~~

~~4.4.2.2 GHG Emissions~~

~~Under Alternative 1.2, the Air District would establish risk action levels at 25/M for cancer risk and 2.5 for hazard indices instead of 10/M and 1.0 respectively. Further, the significant risk level for the compliance alternative for the application of TBARCT would be set at 5 or 2.5. Thus, there would be far fewer facilities that would be required to reduce their risk through the implementation of risk reduction measures and also few sources of risk that would have to be reduced. As a result, construction activities associated with installation of additional air pollution control equipment or implementation of risk reduction measures (such as increasing a stack's height or relocating equipment) would be greatly diminished.~~
~~Therefore, GHG emission associated with Alternative 1.1 would be significantly less than that of proposed Rule 11-18.~~

~~4.4.2.3 Hazards and Hazardous Materials~~

~~Under Alternative 1.2, the Air District would establish risk action levels at 25/M for cancer risk and 2.5 for hazard indices instead of 10/M and 1.0 respectively. Further, the significant risk level for the compliance alternative for the application of TBARCT would be set at 5 or 2.5. Thus, there would be far fewer facilities that would be required to reduce their risk through the implementation of risk reduction measures and also fewer sources of risk that would have to be reduced. As a result, under Alternative 1.2, there would be far fewer additional construction and operational activities at the affected facilities and hazards and the additional use of hazardous~~

~~materials associated with implementation of Rule 11-18 would be greatly diminished. Therefore, GHG emissions associated with the project under Alternative 1.2 would be less than significant.~~

~~4.4.2.3 Hydrology and Water Quality~~

~~Under Alternative 1.2, the Air District would establish risk action levels at 25/M for cancer risk and 2.5 for hazard indices instead of 10/M and 1.0 respectively. Further, the significant risk level for the compliance alternative for the application of TBARCT would be set at 5 or 2.5. This would result in there being far fewer facilities that would be required to reduce their risk through the implementation of risk reduction measures and also few sources of risk that would have to be reduced. Under this project, water demand impacts were determined to be potentially significant, as the use of WGSs would potentially require a significant amount of water to operate. Water quality impacts were determined to be less than significant.~~

~~Under Alternative 1.2 there would be no additional construction and operational activities at the refineries and the additional water use and wastewater discharged associated with implementation of Rule 11-18 would be greatly diminished. Therefore, hydrology and water quality impacts associated with Alternative 2.1 would be less than significant.~~

4.3 ENVIRONMENTAL IMPACTS OF PROJECT ALTERNATIVES

4.3.1 ALTERNATIVE 2.1 – NO PROJECT ALTERNATIVE

4.3.1.1 Air Quality

Under the No Project Alternative (12-16), the proposed rule would not be adopted and facility-wide emissions limits on GHGs, PM (PM_{10} and $PM_{2.5}$), NOx, and SO_2 would not be established. Therefore, potential construction and operational activities associated with installation of additional air pollution control equipment that would be needed to remain in compliance with Rule 12-16 would be eliminated. The air quality impacts associated with proposed Rule 12-16 were potentially significant for NOx during construction and these emissions would be eliminated under Alternative 2.1. ~~However, the construction and operational activities air quality impacts associated with large air pollution control equipment, e.g., WGS, are potentially significant and these air quality impacts may occur under the No Project Alternative (12-16) under the implementation of control measures listed in the Draft 2017 Clean Air Plan.~~

4.3.1.2 GHG Emissions

Under the No Project Alternative (12-16), the proposed rule would not be adopted and facility-wide emissions limits on GHGs, PM (PM_{10} and $PM_{2.5}$), NOx, and SO_2 would not be established. Potential construction activities associated with installation of additional air pollution control equipment that would be needed to remain in compliance with Rule 12-16 would ~~may not~~ be eliminated. The GHG emissions associated with implementation of proposed Rule 12-16 were determined to be less than significant. The GHG emissions under the No Project Alternative would also remain less than significant. ~~the proposed project were determined to be potentially~~

~~significant for GHG emissions during construction and operational activities and less than significant for operational emissions. However, under the No Project Alternative (12-16), indirect GHG emissions impacts due to construction and operational activities associated with large air pollution control equipment, e.g., WGS, are potentially significant and these GHG emission impacts may occur under the implementation of control measures listed in the Draft 2017 Clean Air Plan.~~

4.3.1.3 Hazards and Hazardous Materials

Under the No Project Alternative (12-16), the proposed rule would not be adopted and facility-wide emissions limits on GHGs, PM (PM_{10} and $PM_{2.5}$), NOx, and SO_2 would not be established. Therefore, potential construction activities associated with installation of additional air pollution control equipment that would be needed to remain in compliance with Rule 12-16 would be eliminated. Therefore, construction and operational activities associated with installation of additional air pollution control equipment would be eliminated. The hazards associated with the proposed project were determined to be potentially significant for the operations of baghouses and ESPs. The construction of this equipment would be eliminated under the No Project Alternative. Therefore, hazard impacts would be less than significant. ~~wet gas scrubbers. Hazards impacts associated with the potential installation of this equipment were determined to be less than significant after mitigation.~~

~~Under the No Project Alternative (12-16), there may be additional construction and operational activities at the refineries and hazards and the additional use of hazardous materials associated with implementation control measures listed in the Draft 2017 Clean Air Plan. Therefore, hazards and hazardous materials impacts associated with the No Project Alternative (12-16) were determined to be potentially significant.~~

4.3.1.4 Hydrology and Water Quality

Under the No Project Alternative (12-16), the proposed rule would not be adopted and facility-wide emissions limits on GHGs, PM (PM_{10} and $PM_{2.5}$), NOx, and SO_2 would not be established. Therefore, potential construction activities associated with installation of additional air pollution control equipment that would be needed to remain in compliance with Rule 12-16 would be eliminated. Additionally, the operational activities associated with operation of additional air pollution control equipment, such as wet gas scrubbers, would also be eliminated. Water demand impacts were determined to be potentially significant as the use of WGSs would potentially require a significant amount of water to operate.

Under the No Project Alternative (12-16), there would be no additional construction and operational activities at the refineries and the additional water use and wastewater discharged associated with implementation of Rule 12-16 would be eliminated. Therefore, hydrology and water quality impacts associated with the No Project Alternative (12-16) would be less than significant.

~~4.3.1.4 Utilities / Service Systems~~

~~Under the No Project Alternative (12-16), the proposed rule would not be adopted and facility-wide emissions limits on GHGs, PM (PM_{10} and $PM_{2.5}$), NOx, and SO_2 would not be established. Therefore, potential construction activities associated with installation of additional air pollution control equipment that would be needed to remain in compliance with Rule 12-16 would be eliminated. Additionally, the operational activities associated with operation of additional air pollution control equipment, such as wet gas scrubbers, would also be eliminated. The refineries affected by Rule 12-16 already exist and already use water, generate wastewater, treat wastewater, and discharge wastewater under existing wastewater discharge permits. The rule may potentially require additional air pollution control equipment. As a result, the rule may 1) exceed wastewater treatment requirements of the applicable Regional Water Quality Control Board; 2) require or result in the construction of new water or wastewater treatment facilities or expansion of existing facilities, the construction of which could cause significant environmental effects; 3) result in insufficient water supplies available to serve the project from existing entitlements and resources, or would require new or expanded entitlements; or 4) may result in a determination by the wastewater treatment provider which serves or may serve the project that it has inadequate capacity to serve the project's projected demand in addition to the provider's existing commitments. Under the No Project Alternative (12-16), these impacts may also occur due to the implementation of control measures in the Draft 2017 Clean Air Plan; therefore, the construction and operational utility impacts would be potentially significant.~~

4.3.2 ALTERNATIVE 2.2 – IMPLEMENT RULES 11-18 AND 13-1

4.3.2.1 Air Quality

Under Alternative 2.2, the emissions limits under Rule 12-16 that affect criteria pollutants: $PM_{2.5}$ and PM_{10}, NOx, and SO_2 would not be included under either Rule 11-18 or 13.1. (Emissions limits for GHGs would be established under draft Rule 13.1.) Therefore, potential construction and operational activities associated with installation of additional air pollution control equipment that would be needed to remain in compliance with the criteria pollutant emissions limits under Rule 12-16 would be eliminated. However, air pollution control equipment may be required for compliance under Rule 11-18. NOx emissions associated with construction activities under Rule 11-18 are expected to be potentially significant and they would remain significant under Alternative 2.2 as additional air pollution control equipment would still be required. Operational air quality impacts are expected to remain less than significant under Alternative 2.2. ~~The construction and operational activities associated with large air pollution control equipment, e.g., WGS, are potentially significant and these air quality impacts would be avoided under Alternative 2.2 and, therefore, would be less than significant.~~

4.3.2.2 GHG Emissions

Under Alternative 2.2, the proposed Rule 12-16 would not be adopted and facility-wide emissions limits on PM (PM_{10} and $PM_{2.5}$), NOx, and SO_2 would not be established under either Rule 11-18 or 13.1. (Emissions limits for GHGs would be established under draft Rule 13.1.)

The GHG emissions associated with the proposed project, Rule 12-16, were determined to be ~~potentially significant for GHG emissions during construction activities and~~ less than significant. ~~for operational emissions.~~ Therefore, potential construction and operational activities and impacts associated with installation of additional air pollution control equipment that would be needed to remain in compliance with facility-wide emissions limits for PM, NOx, and SO_2 under Rule 12-16 would be eliminated. Additional air pollution control equipment would be expected to be installed to comply with Rules 11-18 or 13-1. However, GHG impacts are expected to remain ~~be~~ less than significant under Alternative 2.2.

4.3.2.3 Hazards and Hazardous Materials

Under Alternative 2.2, the proposed Rule 12-16 would not be adopted and facility-wide emissions limits on PM (PM_{10} and $PM_{2.5}$), NOx, and SO_2 would not be established. (Emissions limits for GHGs would be established under draft Rule 13.1.) Therefore, potential construction activities associated with installation of additional air pollution control equipment that would be needed to remain in compliance with Rule 12-16 would be eliminated. Therefore, construction and operational activities associated with installation of additional air pollution control equipment would be eliminated. The hazards associated with the proposed Rule 11-18 are expected ~~project were determined~~ to be potentially significant for the operation of baghouses and dry ESPs and this equipment could still be required for compliance with Rule 11-18. ~~wet gas scrubbers.~~ Hazards impacts associated with the potential installation of baghouses and ESPs ~~this equipment~~ were determined to be less than significant after mitigation.

Under Alternative 2.2, baghouses and ESPs could still be required to comply with Rule 11-18. ~~and hazards and the additional use of hazardous materials associated with implementation of Rule 12-16 would be eliminated~~As with Rule 12-16, hazards and hazardous materials impacts associated with Alternative 2.2 would be less than significant following mitigation.

4.3.2.4 Hydrology and Water Quality

Under Alternative 2.2, the proposed Rule 12-16 would not be adopted and facility-wide emissions limits on PM, NOx, and SO_2 would not be established. (Emissions limits for GHGs would be established under draft Rule 13.1.) Therefore, potential construction activities associated with installation of additional air pollution control equipment that would be needed to remain in compliance with Rule 12-16 would be eliminated. Additionally, the operational activities associated with operation of additional air pollution control equipment, such as wet gas scrubbers, would also be eliminated. Water demand impacts were determined to be potentially significant as the use of WGSs would potentially require a significant amount of water to operate.

Under Alternative 2.2, WGSs may still be required under Rule 11-18. ~~there would be no additional construction and operational activities at the refineries and the additional water use and wastewater discharged associated with implementation of Rule 12-16 would be eliminated.~~ Therefore, hydrology and water quality impacts associated with Alternative 2.2 would remain significant for water demand, but water quality impacts are expected to be less than significant.

~~4.3.2.4 Utilities / Service Systems~~

~~Under the Alternative 2.2, the proposed rule would not be adopted and facility-wide emissions limits on PM, NOx, and SO_2 would not be established. (Emissions limits for GHGs would be established under draft Rule 13.1.) Therefore, potential construction activities associated with installation of additional air pollution control equipment that would be needed to remain in compliance with Rule 12-16 would be eliminated. Additionally, the operational activities associated with operation of additional air pollution control equipment, such as wet gas scrubbers, would also be eliminated. The refineries affected by Rule 12-16 already exist and already use water, generate wastewater, treat wastewater, and discharge wastewater under existing wastewater discharge permits. The rule may potentially require additional air pollution control equipment. As a result, the rule may 1) exceed wastewater treatment requirements of the applicable Regional Water Quality Control Board; 2) require or result in the construction of new water or wastewater treatment facilities or expansion of existing facilities, the construction of which could cause significant environmental effects; 3) result in insufficient water supplies available to serve the project from existing entitlements and resources, or would require new or expanded entitlements; or 4) may result in a determination by the wastewater treatment provider which serves or may serve the project that it has inadequate capacity to serve the project's projected demand in addition to the provider's existing commitments. Under Alternative 2.2, these impacts would be eliminated; therefore, the construction and operational utility impacts would be less than significant.~~

~~4.6 ENVIRONMENTALLY SUPERIOR ALTERNATIVE – RULE 11-18~~

~~Pursuant to CEQA Guidelines §15126.6(e)(2), if the environmentally superior alternative is the "no project" alternative, the EIR shall also identify an environmentally superior alternative among the other alternatives.~~

~~4.6.1 ALTERNATIVE 1.1 – THE NO PROJECT ALTERNATIVE (11-18)~~

~~Alternative 1.1 – the No Project Alternative (11-18) would reduce the potentially significant impacts associated with construction criteria pollutant and GHG emissions and water demand associated with the potential installation of additional air pollution control equipment to less than significant. The potential beneficial impacts of the proposed project associated with risk and emission reductions of TACs would also be eliminated under the No Project Alternative (11-18). Since the needs for risk and emission reductions have yet to be determined, the amount of emissions reductions that would not occur under Alternative 1.1 is unknown. Further, the No Project Alternative (11-18) would achieve only two of the project objectives:~~

2) ~~Incorporate the most up-to-date health risk methodologies and health values into the Air District's risk evaluation process for existing stationary sources of TACs; and~~
4) ~~Provide the public opportunity to comment on the draft HRAs to provide transparency and clarity to the process; and~~

~~4.6.2 ALTERNATIVE 1.2 – SET RISK ACTION LEVEL AT 25/M CANCER AND 2.5 HAZARD INDICES~~

~~The environmentally superior alternative is Alternative 1.2. Under Alternative 1.2, the Air District would establish risk action levels at 25/M for cancer risk and 2.5 for hazard indices instead of 10/M and 1.0 respectively. Further, the significant risk level for the compliance alternative for the application of TBARCT would be set at 5/M for cancer and 0.5 hazard indices or removed. Under this alternative, the scope of the project would be significantly reduced because the rule would not apply to those facilities with health risks that lie between either 10/M and 25/M for cancer or 1.0 and 2.5 for hazard indices. Thus, the number of facilities affected by the rule would be reduced by from approximately 1,000 to fewer than 100 – an order of magnitude reduction. Alternative 1.2 would eliminate or significantly reduce the air quality, water quality, and GHG emission impacts associated with the proposed project. Alternative 1.2 would achieve the following project objectives:~~

1) ~~Incorporate the most up-to-date health risk methodologies and health values into the Air District's risk evaluation process for existing stationary sources of TACs;~~
2) ~~Ensure the facilities that impact the most sensitive and overburdened communities reduce their associated health risk in an efficient and expeditious manner;~~
3) ~~Provide the public opportunity to comment on the draft HRAs to provide transparency and clarity to the process; and~~
4) ~~Provide the public opportunity to comment on risk reduction plans as they are drafted by the affected facilities.~~

4.4 ENVIRONMENTALLY SUPERIOR ALTERNATIVE

4.4.1 ALTERNATIVE 2.1 – THE NO PROJECT ALTERNATIVE

Alternative 2.1 – the No Project Alternative (12-16) was determined to eliminate or reduce the ~~have~~ potentially significant impacts in air quality ~~and GHG emissions~~ impacts, hazard and hazardous material impacts, ~~hydrology~~ and water demand impacts ~~quality impacts, utilities / service systems demand~~ associated with the potential installation and operation of additional air pollution control equipment. ~~due to the implementation of several control measures contained in the draft 2017 Clean Air Plan. Therefore, the No Project Alternative (12-16) is not the environmentally superior alternative.~~ However, No Project Alternative (12-16) would not achieve the following project objectives:

1) Protect air quality, public health, and the climate from increases in annual facility-wide mass emissions of GHGs, PM, NOx, and SO_2 caused by changes in refinery oil feed quality or quantity, refinery or support equipment or operation, or combinations of these causes, by preventing any significant increase in these emissions;
2) Protect the climate and public health by preventing any significant increase in these emissions at refineries and associated facilities from increasing the emission intensity of the production of transportation fuels;
3) Protect community and public health by preventing any significant increase in these emissions from worsening hazards for which HRA methods may not account, including

but not limited to acute and chronic ambient PM, NOx, SO_2, and PM exposure hazards; and

4) Complement other air quality, public health, and climate measures by discouraging investment in new refinery equipment that would lead to increased emissions of GHG, PM, NOx, or SO_2 from Bay Area refineries.

4.4.2 ALTERNATIVE 2.2 – IMPLEMENT RULES 11-18 AND 13-1

If the environmentally superior alternative is the “no project” alternative, the EIR shall also identify an environmentally superior alternative among the other alternatives (CEQA Guidelines §15126.6(e(2)). Alternative 2.1 would eliminate all significant impacts; however, it would not achieve any of the project objectives. ~~The environmentally superior alternative is~~ Alternative 2.2 is considered to be the environmentally superior alternative. Under Alternative 2.2, the emissions limits under Rule 12-16 that affect criteria pollutants: $PM_{2.5}$ and PM_{10}, NOx, and SO_2 would not be included under either Rule 11-18 or 13.1. (Emissions limits for GHGs would be established under draft Rule 13.1.) Alternative 2.2 would still result in significant impacts for air quality (during construction, and water demand but they would be less than the proposed project. ~~have less than significant impacts for air quality, GHG emissions, hazard / hazardous material, hydrology and water quality, and utilities / service systems.~~ Further, Alternative 2.2 would achieve the following project objectives:

1) Protect air quality, public health, and the climate from increases in annual facility-wide mass emissions of GHGs, PM, NOx, and SO_2 caused by changes in refinery oil feed quality or quantity, refinery or support equipment or operation, or combinations of these causes, by preventing any significant increase in these emissions;
2) Protect the climate and public health by preventing any significant increase in these emissions at refineries and associated facilities from increasing the emission intensity of the production of transportation fuels;
3) Protect community and public health by preventing any significant increase in these emissions from worsening hazards for which HRA methods may not account, including but not limited to acute and chronic ambient PM, NOx, SO_2, and PM exposure hazards; and
4) Complement other air quality, public health, and climate measures by discouraging investment in new refinery equipment that would lead to increased emissions of GHG, PM, NOx, or SO_2 from Bay Area refineries.

4.5 COMPARISON OF ALTERNATIVES

Pursuant to CEQA Guidelines §15126.6(d), an EIR should include sufficient information about each alternative to allow meaningful comparison with the proposed project. Section 15126.6(d) also recommends the use of a matrix to summarize the comparison. Table 4.5-1 ~~4-2a and 4-2b~~ below provide these matrix comparisons. The CEQA document shall include sufficient information about each alternative to allow meaningful evaluation, analysis, and comparison with the proposed project (CEQA Guidelines §15126.6(d)). A matrix displaying the major characteristics and significant environmental effects of each alternative may be used to summarize the comparison. Table 4.5-1 ~~4-2a and 4-2b~~ at the end of this section lists the alternatives considered in this EIR and how they compare to the two proposed rules. Table 4.5-1-~~10~~ presents a matrix that lists the significant adverse impacts associated with the proposed project and the project alternatives for all environmental topics analyzed. The tables also rank each section as to whether the proposed project or a project alternative would result in greater or lesser impacts relative to one another.

~~4.8.1 COMPARISON OF ALTERNATIVES TO RULE 11-18~~

~~Alternative 1.1 – No Project Alternative (11-18) was determined to result in less than significant environmental impacts. Compared to the other project alternative, the No Project Alternative (11-18) would not achieve the critical project objective of health risk reductions. It would achieve only two of the objectives of the proposed project (Rule 11-18): Objectives 2 and 4. Because the current risk action levels established by the Air Toxic "Hot Spots" Program would remain unchanged, this alternative would not result in any facilities having to reduce their health risk nor having to develop a risk reduction plan because preliminary analyses show that there are likely no facilities that would pose a health risk in excess of the current risk action levels of 100/M for cancer and 10 for hazard indices.~~

~~Alternative 1.2 was determined to result in less than significant environmental impacts while achieving, to a lesser extent, the critical project objective of health risk reductions at some of the affected facilities (Objective 1) and expeditiously reduce health risk in impacted communities (Objective 3). This alternative would also achieve the remaining three objectives.~~

~~The proposed project has been demonstrated to be the most effective project that achieves all of the project objective relative to environmental impact generated. Mitigation measures have been developed to minimize the potential increase in water demand, while providing the greatest public health benefit by reducing health risk from stationary sources to the greatest feasible extent. Therefore, the proposed project is the preferred alternative.~~

4.5.1 COMPARISON OF ALTERNATIVES TO RULE 12-6

Alternative 2.1 ~~– No Project Alternative (12-16~~ would eliminate the potentially significant impacts of air quality during construction and water demand, but would not achieve the project objectives. ~~was determined to result in potentially significant environmental impacts, while achieving most of the project alternatives.~~

Alternative 2.2 would achieve all the project objectives ~~alternative~~ to a greater extent than the proposed project, with a reduced ~~n equivalent~~ level of ~~the~~ environmental impacts as compared to the proposed project. A combination of Rule 11-18 and Rule 13-1 would directly reduce health risks from refining operations through the implementation of risk reduction measures and limit GHG emissions from refining operation.~~ without the anticipated legal pitfalls associated with the proposed project.~~ Therefore, the Alternative 2.2 is the preferred alternative.

TABLE 4.5-1[(1)]

Comparison of Alternatives to Proposed Rule 12-16

Environmental Topic	Proposed Project	No Project Alternative (12-16)	Alternative 2.2
Air Quality			
Air Quality Impacts	S	NS(-)	S(-)
Toxic Air Contaminants	NS	NS(-)	NS(-)
GHG			
GHG Impacts	NS	NS(-)	NS(=)
Hazards & Hazardous Materials			
Hazard Impacts	MNSS	NS(-)	MNS(-)
Hydrology / Water Quality			
Water Demand Impacts	S	NS(-)	S(-)
Water Quality Impacts	S	NS(-)	NS(-)

(1) Table 4.5-1 replaces Tables 4-2a and 4-2b. Track changes was not used to make the table more readable.

Notes:
S = Significant
NS = Not Significant
MNS = Mitigated Not Significant
(-) = Potential impacts are less than the proposed project.
(+) = Potential impacts are greater than the proposed project.
(=) = Potential impacts are approximately the same as the proposed project.

~~Table 4-2a~~

~~Comparison of Alternatives to Proposed Rule 11-18~~

~~Environmental Topic~~	~~Proposed Project~~	~~No Project Alternative (11-18)~~	~~Alternative 1.2~~
~~Air Quality~~			
~~Air Quality Benefits~~	~~B~~	~~B(-)~~	~~B(-)~~
~~Air Quality Impacts~~	~~S~~	~~NS(-)~~	~~NS(-)~~
~~Toxic Air Contaminants~~	~~B~~	~~B(-)~~	~~NS(-)~~
~~GHG~~			
~~GHG Reductions~~	~~NS~~	~~NS(=)~~	~~NS(-)~~
~~GHG Impacts~~	~~S~~	~~NS(-)~~	~~S(-)~~
~~Hazards & Hazardous Materials~~			
~~Hazard Impacts~~	~~S~~	~~S(-)~~	~~S(-)~~
~~Hydrology / Water Quality~~			
~~Water Demand Impacts~~	~~S~~	~~NS(-)~~	~~S(-)~~
~~Water Quality Impacts~~	~~NS~~	~~NS(-)~~	~~NS(-)~~
~~Utilities / Service Systems~~			
~~Electricity Demand Impacts~~	~~S~~	~~NS(-)~~	~~S(-)~~
~~Solid / Hazardous Waste Impacts~~	~~S~~	~~NS(-)~~	~~S(-)~~

~~Table 4-2b~~
~~Comparison of Alternatives to Proposed Rule 12-16~~

~~**Environmental Topic**~~	~~**Proposed Project**~~	~~**No Project Alternative (12-16)**~~	~~**Alternative 2.2**~~
~~**Air Quality**~~			
~~Air Quality Benefits~~	~~B~~	~~B(+)~~	~~B(+)~~
~~Air Quality Impacts~~	~~S~~	~~S(+)~~	~~S(-)~~
~~Toxic Air Contaminants~~	~~NS~~	~~NS(+)~~	~~B(+)~~
~~**GHG**~~			
~~GHG Reductions~~	~~NS~~	~~NS(+)~~	~~NS(−)~~
~~GHG Impacts~~	~~S~~	~~S(+)~~	~~S(−)~~
~~**Hazards & Hazardous Materials**~~			
~~Hazard Impacts~~	~~S~~	~~S(+)~~	~~S(-)~~
~~**Hydrology / Water Quality**~~			
~~Water Demand Impacts~~	~~S~~	~~S(+)~~	~~S(-)~~
~~Water Quality Impacts~~	~~S~~	~~S(+)~~	~~S(-)~~
~~**Utilities / Service Systems**~~			
~~Electricity Demand Impacts~~	~~S~~	~~S(+)~~	~~S(-)~~
~~Solid / Hazardous Waste Impacts~~	~~S~~	~~S(+)~~	~~S(-)~~

CHAPTERS 3.6, 3.7, and 3.8

GROWTH INDUCING IMPACTS
SIGNIFICANT ENVIRONMENTAL EFFECTS WHICH CANNOT BE AVOIDED
POTENTIAL ENVIRONMENTAL IMPACTS FOUND NOT TO BE SIGNIFICANT

Introduction
Growth Inducing Impacts
Significant Environmental Effects Which Cannot Be Avoided and Significant Irreversible Environmental Changes
Potential Environmental Impacts Found Not to Be Significant

3.6 GROWTH INDUCING IMPACTS

3.6.1 INTRODUCTION

CEQA defines growth-inducing impacts as those impacts of a proposed project that "could foster economic or population growth, or the construction of additional housing, either directly or indirectly, in the surrounding environment. Included in this are projects, which would remove obstacles to population growth" (CEQA Guidelines §15126.2(d)).

To address this issue, potential growth-inducing effects are examined through the following considerations:

- Facilitation of economic effects that could result in other activities that could significantly affect the environment;
- Expansion requirements for one or more public services to maintain desired levels of service as a result of the proposed Project modifications;
- Removal of obstacles to growth, e.g., through the construction or extension of major infrastructure facilities that do not presently exist in the project area or through changes in existing regulations pertaining to land development;
- Adding development or encroachment into open space; and/or
- Setting a precedent that could encourage and facilitate other activities that could significantly affect the environment.

3.6.2 ECONOMIC AND POPULATION GROWTH, AND RELATED PUBLIC SERVICES

The proposed rule would not directly foster economic or population growth or the construction of new housing in the Bay area. The proposed rule may require construction of air pollution control equipment or operational measures/modifications within the confines of the existing industrial facilities but would not be expected to involve new development outside of existing facilities. Therefore, it would not stimulate significant population growth, remove obstacles to population growth, or necessitate the construction of new community facilities that would lead to additional growth.

A project would directly induce growth if it would directly foster economic or population growth or the construction of new housing in the surrounding environment (e.g., if it would remove an obstacle to growth by expanding existing infrastructure). The proposed new rules would not remove barriers to population growth, as it involves no changes to General Plan, zoning ordinance, or related land use policy. The proposed new rules do not include the development of new housing or population-generating uses or infrastructure that would directly encourage such uses.

Therefore, proposed Regulation~~s 11-18 and~~ 12-16 would not directly trigger new residential development in the District.

Further, the proposed rule would not result in an increase in local population, housing, or associated public services (e.g. fire, police, schools, recreation, and library facilities) since the proposed amendments would not result in an increase in workers or residents. Likewise, the proposed amendments would not create new demand for secondary services, including regional or specialty retail, restaurant or food delivery, recreation, or entertainment uses. As such, the proposed amendments would not foster economic or population growth in the surrounding area in a manner that would be growth-inducing.

3.6.3 REMOVAL OF OBSTACLES TO GROWTH

The proposed rule would not employ activities or uses that would result in growth inducement, such as the development of new infrastructure (i.e., new roadway access or utilities, such as wastewater treatment facilities) that would directly or indirectly cause the growth of new populations, communities, or currently undeveloped areas. Likewise, the proposed rule would not result in an expansion of existing public service facilities (e.g., police, fire, libraries, and schools) or the development of public service facilities that do not already exist.

3.6.4 DEVELOPMENT OR ENCROACHMENTS INTO OPEN SPACE

Development can be considered growth-inducing when it is not contiguous to existing urban development and introduces development into open space areas. The proposed rule may require additional air pollution control equipment and measures within the confines of existing facilities and existing industrial areas. New development outside of the boundaries of industrial facilities is not expected to occur. Therefore, the proposed rule would not result in development within or encroachment into an open space area.

3.6.5 PRECEDENT SETTING ACTION

Proposed Rule 12-16 will enforce emission limits on existing refineries.~~, while 11-18 would lead to further control of TAC emissions.~~ These types of emissions limiting-activities are currently required of refineries and other industrial facilities to comply with various regulatory requirements. GHG emissions from refineries are required to be tracked, reported to CARB under the AB32 GHG requirements, and GHG limits have been established on sources within California's Cap and Trade program, including refineries.

~~Emissions of TACs are currently required to be reported and HRAs are required to be prepared under AB2588 for various industrial facilities. Proposed Rule 11-18 would reduce the acceptable health risk limits for stationary sources of emissions. However, the requirement for the preparation of emission inventories and HRAs already exists under state law. Establishing thresholds, reporting emission inventories, conducting HRAs and additional monitoring requirements would not result in precedent-setting actions that might cause significant environmental impacts.~~

3.6.6 CONCLUSION

The proposed new rule would not be considered growth-inducing, because it ~~they~~ would not result in an increase in production of resources or cause a progression of growth that could significantly affect the environment either individually or cumulatively.

3.7 SIGNIFICANT ENVIRONMENTAL EFFECTS WHICH CANNOT BE AVOIDED AND SIGNIFICANT IRREVERSIBLE ENVIRONMENTAL CHANGES

Section 15126.2(b) of the CEQA Guidelines requires that an EIR describe significant environmental impacts that cannot be avoided, including those effects that can be mitigated but not reduced to a less than significant level. As evaluated in the preceding portions of Chapter 3 of this EIR, the proposed rule~~s 11-18 and~~ 12-16 would result in potentially significant unavoidable impacts as identified in Table 3.7-1.

TABLE 3.7-1

IMPACTS IDENTIFIED AS POTENTIALLY SIGNIFICANT IN THIS EIR

~~**RULE 11-18**~~	**RULE 12-16**
~~NOx Emissions During Construction~~	NOx Emissions During Construction
~~NOx Emissions During Operation~~	Water Demand Impacts
~~GHG Impacts~~	
~~Water Demand Impacts~~	

3.8 POTENTIAL ENVIRONMENTAL IMPACTS FOUND NOT TO BE SIGNIFICANT

The environmental effects of Rule 12-16 that may have potentially significant adverse effects on the environment are identified, evaluated, and discussed in detail in the preceding portions of Chapter 3 of this EIR and in the Initial Study (see Appendix A) per the requirements of the CEQA Guidelines (§§15126(a) and 15126.2). The potentially significant adverse environmental impacts as determined by the Initial Study (see Appendix A) include: air quality; greenhouse gas emissions; hazards and hazardous materials; hydrology and water quality; and water demand under utilities and service systems. The water demand impacts were determined to be significant under hydrology/water quality and utilities and services. To avoid repetition, the water demand impacts have been included under the hydrology and water quality impacts only. The analysis provided in the Initial Study has concluded that the following environmental topics would be less than significant: aesthetics; agriculture and forestry resources; biological resources; cultural resources; geology and soils; land use and planning; mineral resources; noise, population and housing; public services, recreation, transportation and traffic, and utilities and service systems (impacts other than water demand). The reasons for finding the environmental resources to be less than significant are explained below.

3.8.1 AESTHETICS

Rule 12-16 would affect the four petroleum refineries that are located in Contra Costa County and one that is located in Solano County (Valero) and also three refinery-related facilities located in Contra Costa County, all of which are in areas designated for industrial facilities. Refineries and other facilities affected by proposed Rule 12-16 are generally located in industrial areas and compliance is not expected to result in any aesthetic changes to the facilities. Scenic highways or corridors are generally not located in the vicinity of these facilities.

The facilities affected by the proposed Regulation 12-16 may be required to install additional air pollution control equipment or modify operations. Further, refinery modifications may require additional lighting. However, refineries are already lighted for night-time operations and safety measures, and are located in appropriately zoned areas that are not usually located next to residential areas. New light sources, if any, are not expected to be noticeable in residential areas. Most local land use agencies have ordinances that limit the intensity of lighting and its effects on adjacent property owners. Therefore, the proposed new rule is not expected to have significant adverse aesthetic impacts to the surrounding community

3.8.2 AGRICULTURE AND FORESTRY RESOURCES

Rule 12-16 would affect five refineries and three related facilities. The facilities affected by Rule 12-16 are located in industrial areas where agricultural or forest resources are generally not located. All construction associated with compliance with the rules is expected to occur on the premises of the affected refineries. Therefore, the rule is not expected to convert agricultural or forest lands, or involve Williamson Act contracts.

3.8.3 BIOLOGICAL RESOURCES

The areas affected by the proposed new rule are located in the Bay Area-Delta Bioregion (as defined by the State's Natural Communities Conservation Program). This Bioregion is comprised of a variety of natural communities, which range from salt marshes to chaparral to oak woodland.

The refineries affected by proposed Rule 12-16 have been graded to develop various permanent refinery structures, buildings, operating units and storage tanks. Native vegetation, other than landscape vegetation, has generally been removed from the operating portions of the refineries to minimize safety and fire hazards. Construction of any air pollution control equipment would take place within the operating portions of existing refineries which are void of biological resources and would not impact sensitive biological resources directly or indirectly, impact riparian habitats, or protected wetlands. The installation of air pollution control equipment would also not interfere with the movement of any migratory fish or wildlife species or impacts migratory corridors; would not conflict with local policies or ordinances protecting biological resources; and would not conflict with an adopted habitat conservation plan.

3.8.4 CULTURAL RESOURCES

No impacts on cultural resources are anticipated from the proposed Rule 12-16 that would apply to existing refineries. Historic resources are typically not located within refineries and no demolition activities are expected to be required so no impacts on historic resources are expected. Construction activities would be limited to areas within existing refineries boundaries, i.e., within areas that have already been graded and developed. Therefore, construction activities are not expected to impact cultural resources, including historical buildings, tribal resources, paleontological resources, and archaeological resources, either directly or indirectly, or disturb human remains.

3.8.5 GEOLOGY AND SOILS

The San Francisco Bay Area is a seismically active region, which is situated on a plate boundary marked by the San Andreas Fault System. Several northwest trending active and potentially active faults are included with this fault system. Under the Alquist-Priolo Earthquake Fault Zoning Act, Earthquake Fault Zones were established by the California Division of Mines and Geology along "active" faults, or faults along which surface rupture occurred in Holocene time (the last 11,000 years). In the Bay area, these faults include the San Andreas, Hayward, Rodgers Creek-Healdsburg, Concord-Green Valley, Greenville-Marsh Creek, Seal Cove/San Gregorio and West Napa faults. Other smaller faults in the region classified as potentially active include the Southampton and Franklin faults.

The facilities affected by any Air District control equipment requirements are typically located in industrial or commercial areas, which are not typically located near known geological hazards. Rule 12-16 will not directly expose people or structures to earthquake faults, seismic shaking, seismic-related ground failure including liquefaction, landslides, mudslides, or substantial soil erosion. New structures must be designed to comply with the California Building Code requirements since the Air District is located in a seismically active area. Construction activities would be limited to the confines of existing industrial facilities and will not require substantial grading.

3.8.6 LAND USE AND PLANNING

The proposed rules are not expected to require any new substantial construction or development. New or modified pollution control equipment or enclosures would be located within existing industrial facilities. Construction activities would be limited to the confines of existing facilities which are zoned for industrial land use. Modifications are not expected to affect adjacent land uses, divide an established community, conflict with any applicable land use plan or policy or conflict with any habitat conservation plan. Therefore, significant adverse project-specific impacts to land use and planning are not expected to occur due to implementation of proposed Rule 12-16

3.8.7 MINERAL RESOURCES

Rule 12-16 does not contain provisions that would directly result in the loss of availability of a known mineral resource of value to the region and the residents of the state, or of a locally-important mineral resource recovery site delineated on a local general plan, specific plan or other land use plan. The proposed rule is not expected to deplete non-renewable mineral resources, such as aggregate materials, metal ores, etc., at an accelerated rate or in a wasteful manner because the control measures are typically not mineral resource intensive measures. Therefore, significant adverse impacts to mineral resources are not anticipated.

3.8.8 NOISE

The existing noise environment at each of the affected facilities and refineries are typically dominated by noise from existing equipment onsite, vehicular traffic around the facilities, and trucks entering and exiting facility premises. No new major industrial equipment is expected to be required to be installed due to the proposed project so that no noise impacts associated with the operation of the proposed rule are expected. Air pollution control equipment is not generally a major noise source. Further, all noise producing equipment must comply with local noise ordnances and applicable OSHA and Cal/OSHA noise requirements. Therefore, industrial operations affected by the proposed new rule are not expected to have a significant adverse effect on local noise control laws or ordinances.

Construction activities associated with the proposed rule may generate some noise associated with temporary construction equipment and construction-related traffic. The petroleum refineries affected by Rule 12-16 already exist and operate within the confines of existing industrial facilities. Any substantial construction activities associated with new refinery equipment would occur within the confines of existing refineries, located within industrial areas. However, those construction activities would be required to comply with local noise ordinances, which generally prohibit construction during the nighttime, in order to minimize noise impacts. Compliance with local noise ordinances is expected to minimize noise impacts associated with construction activities to less than significant.

Ambient noise levels in industrial area are typically driven primarily by freeway and/or highway traffic in the area and any heavy-duty equipment used for materials manufacturing or processing. It is not expected that any modifications to install air pollution control equipment would substantially increase operational noise levels in the area, either permanently or intermittently, or expose people to excessive noise levels that would be noticeable above and beyond existing ambient levels. Affected refineries would be required to comply with local noise ordinances and elements, which may require construction of noise barriers or other noise control devices. Consequently Rule 12-16 is not expected to directly or indirectly cause substantial noise impacts.

3.8.9 POPULATION AND HOUSING

The current population of the Bay Area is about seven million people and is expected to grow to about nine million people by 2035 according to the Association of Bay Area Governments (ABAG, 2007). The proposed rule is not anticipated to generate any significant effect, either directly or indirectly, on the Bay Area's population or population distribution as Rule 12-16 would affect existing refineries located in industrial areas. It is expected that the existing labor pool will be sufficient to accommodate any requirements for modifications or increased demand for workers that might occur as a result of implementing the proposed rule. Furthermore, the proposed rule is not expected to require construction activities that would displace people or existing housing as construction activities are expected to occur exclusively within the confines of existing facilities. Thus, adopting Rule 12-16 would not induce substantial population growth.

3.8.10 PUBLIC SERVICES

There is no potential for adverse public service impacts as a result of adopting Rule 12-16 as it would not result in the need for new or physically altered government facilities to maintain acceptable service ratios, response times, or other performance objectives. The existing refineries have on site security and fire protection personnel, so no increase in police or fire protection services is expected. Implementing the proposed rule would not cause a future population increase, thus it is not expected to affect land use plans, future development, or the demand for public facilities such as schools and parks.

3.8.11 RECREATION

As discussed under "Land Use and Planning" and "Population and Housing," there are no provisions of the proposed project that would affect land use plans, policies, ordinances, or regulations as land use and other planning considerations are determined by local governments. No land use or planning requirements, including those relating to recreational facilities, will be altered by Rule 12-16. The rule does not have the potential to directly or indirectly induce population growth or redistribution. As a result, the proposed project would not increase the use of, or demand for, existing neighborhood or regional parks or other recreational facilities nor require the construction or expansion of recreational facilities that might have an adverse physical effect on the environment.

3.8.12 TRANSPORTATION AND TRAFFIC

The petroleum refineries affected by the proposed new rule already exist and operate within the confines of existing industrial facilities in the Bay Area. Construction activities could be required to install air pollution control equipment associated with compliance with the emissions limits contained in the proposed rule. Any substantial construction activities associated with new refinery equipment would occur within the confines of existing refineries. Construction activities are temporary and the related construction worker traffic and delivery trucks would cease following completion of construction. The proposed rule is not expected to exceed, either individually or cumulatively, the current level of service at intersections in the vicinity of the refineries. The work force at each affected facility is not expected to substantially change as a result of the proposed regulations and any permanent increase in operation-related traffic is expected to be minimal. Thus, the traffic impacts associated with the proposed Rule 12-16 are expected to be less than significant.

Additionally, Rule 12-16 is not expected to result in any changes to traffic patterns, the creation of hazardous intersections, result in inadequate emergency access, or conflict with adopted policies involving mass transit or non-motorized travel.

3.8.13 UTILITIES AND SERVICE SYSTEMS

The NOP/IS found that there were potentially significant impacts for utilities and service systems for water use and wastewater treatment. However, because these issues are specific to water, the associated potential impacts are discussed in Chapter 3.5 of the DEIR (hydrology and water quality).

No significant impacts are expected on solid waste disposal for Rule 12-16. Baghouses and catalytic oxidizers will generate solid waste, but they are not expected to require annual replacement events. The baghouses and spent catalyst are only expected to generate a few tons of waste per change out. It is assumed that any hazardous material will be taken to the U.S. Ecology Beatty Nevada hazardous waste facility for treatment and disposal. U.S. Ecology, Inc. is currently receiving waste, and is in the process of extending the operational capacity for an additional 35 years (U.S. Ecology, 2015). Clean Harbors in Grassy Mountain, Utah is also available to receive hazardous waste and is expected to continue to receive waste for an additional 70 years (Clean Harbors, 2015). Additionally, the air pollution control equipment would be installed at already existing facilities and refineries, which have systems in place for processing and disposing solid and hazardous waste. Therefore, the proposed project impacts on solid waste and hazardous waste landfills are less than significant.

CHAPTER 3.5

HYDROLOGY AND WATER QUALITY

Introduction
Environmental Setting
Regulatory Setting
Significance Criteria
Hydrology and Water Quality Impacts

3.5 HYDROLOGY AND WATER QUALITY

This subchapter of the EIR evaluates the potential hydrology and water quality impacts associated with implementation of Rule~~s 11-18 and/or~~ 12-16. Rule 12-16 would establish numeric emission limits on specific refinery and associated facilities within the Bay Area. ~~Rule 11-18 would reduce exposure to TAC emissions from a number of stationary sources within the Bay Area, including refineries.~~

~~As discussed in the Initial Study, implementation of Rule 11-18 would reduce risk from facilities that emit toxic air contaminants throughout the Bay Area. Risk reduction measures are expected to be limited to new air pollution control equipment and construction of enclosures. The NOP/IS concluded that wet gas scrubbers were not expected to be used to control TACs; therefore, implementation of Rule 11-18 was not expected to result in a substantial increase in water use or wastewater discharge. However, public comments received on the NOP/IS indicated that wet gas scrubbers could be used to control TAC emissions from some refinery sources, such as FCCUs.~~

Implementation of Rule 12-16 would prevent refinery emissions of GHGs and some criteria pollutants from increasing. However, Rule 12-16 could require the installation of additional air pollution control equipment or modifications to refinery operations. Control measures for particulate matter and/or SOx emissions could require additional water use and wastewater discharge from devices like wet gas scrubbers. The NOP/IS (see Appendix A) determined that potential hydrology and water quality impacts associated with implementation of the proposed new Rule 12-16 are potentially significant. The NOP/IS determined that the potential flooding, flood hazards and increased stormwater runoff was less than significant ~~for both rules~~ as modifications would occur at existing facilities that have been graded and developed. Therefore, project-specific and cumulative adverse water demand and water quality impacts associated with implementation of proposed Rule~~s 11-18 and~~ 12-16 has ~~have~~ been evaluated in Chapter 3.5 of this EIR.

3.5.1 ENVIRONMENTAL SETTING

3.5.1.1 Regional Hydrology

The state of California is divided into ten hydrologic regions corresponding to the state‘s major water drainage basins. The hydrologic regions define a river basin drainage area and are used as planning boundaries, which allows consistent tracking of water runoff, and the accounting of surface water and groundwater supplies. The Air District is within the San Francisco Bay Hydrologic Region (Bay Region) which includes all of San Francisco County and portions of Marin, Sonoma, Napa, Solano, San Mateo, Santa Clara, Contra Costa, and Alameda counties. It occupies approximately 4,500 square miles; from southern Santa Clara County to Tomales Bay in Marine County; and inlad to near the confluence of the Sacramento and San Joaquin rivers at the eastern end of Suisun Bay. The eastern boundary follows the crest of the Coast Ranges, where the highest peaks are more than 4,000 feet above mean sea level (DWR, 2013a).

Some water agencies in the region have imported water from the Sierra Nevada for nearly a century to supply their customers. Water from the Mokelumne and Tuolumne rivers accounts for about 38 percent of the region's average annual water supply. Water from the Sacramento-San Joaquin Delta (Delta), via the federal Central Valley Project (CVP) and the State Water Project (SWP), accounts for another 28 percent. Approximately 31 percent of the average annual water supply is from local groundwater and surface water, and 3 percent is from miscellaneous sources such as harvested rainwater, recycled water, and transferred water. Population growth and diminishing water supply and water quality have led to the development of local surface water supplies, recharge of groundwater basins, and incorporation of conservation guidelines to sustain water supply and water quality for future generations (DWR, 2013a).

The San Francisco Bay estuary system is one of the largest in the country and drains approximately 40 percent of the state's surface water from the Sierra Nevada and the Central Valley. The two major drainages, the Sacramento and San Joaquin Rivers, receive more than 90 percent of runoff during the winter and spring months from rainstorms and snow melt. Water from these drainages flows into what is known as the Delta region, then into the sub-bays, Suisun Bay and San Pablo Bay, and finally into the Central Bay and out the Golden Gate. Nearly half of the surface water in California starts as rain or snow that falls within the watershed and flows downstream toward the Bay. Much of the water flowing toward the Bay is diverted for agricultural, residential, and industrial purposes as well as delivery to distant cities of southern California as part of state and federal water projects.

San Francisco Bay encompasses approximately 1,600 square miles and is surrounded by the nine Bay Area counties of which seven borders the Bay. Other surface waters flow either directly to the Bay or Pacific Ocean. The drainage basin that contributes surface water flows directly to the Bay covers a total area of 3,464 square miles. The largest watersheds include Alameda Creek (695 square miles), the Napa River (417 square miles), and Coyote Creek (353 square miles) watersheds. The San Francisco Bay estuary includes deep-water channels, tidelands, and marshlands that provide a variety of habitats for plants and animals. The salinity of the water varies widely, as the landward flows of saline water and the seaward flows of fresh water converge near the Benicia Bridge. The salinity levels in the Central Bay can vary from near oceanic levels to one-quarter as much, depending on the volume of freshwater runoff (ABAG, 2013).

3.5.1.2 Surface Water Hydrology

The California Department of Water Resources (DWR) has grouped the watersheds in the Bay Region into six principle watersheds. These watersheds drain into Suisun Bay, San Pablo Bay, North San Francisco Bay, South San Francisco Bay, or directly into the Pacific Ocean. Large streams such as the Guadalupe River and Coyote and Alameda creeks, drain from the Coast Ranges and generally flow northwest into San Francisco Bay. The Alameda Creek watershed is the largest in the region at nearly 700 square miles. The Napa River originates in the Mayacamas Mountains at the northern end of Napa Valley and flows south into San Pablo Bay. Sonoma Creek begins in mountains within Sugarloaf State Park, then flows south through Sonoma Valley into San Pablo Bay. The major watersheds of the San Francisco Bay hydrologic region are summarized in Table 3.5-1.

TABLE 3.5-1

Watersheds of the San Francisco Bay Hydrologic Region

LOCATION	WATERSHED
North Bay	Corte Madera Creek Watershed
	Novato Creek Watershed
	Petaluma River Watershed
	Napa River Watershed
	Marin and North Bay Coastal Drainages(1)
Suisun Bay	GreenValley/Suisun Creeks watersheds
	Walnut Creek Watershed
	San Pablo/Wildcat Creeks Watersheds
	Suisun Bay Drainages(2)
East Bay	San Leandro Creek Watershed
	San Lorenzo Creek Watershed
	Alameda Creek Watershed
	East Bay Drainages(3)
South Bay	Coyote Creek Watershed
	Guadalupe River Watershed
	West Santa Clara Valley Drainages(4)
Peninsula	San Francisquito Creek Watershed
	San Mateo Creek Watershed
	San Mateo and Peninsula Coastal Drainages(5)

Source: AGAG, 2013

(1) Including Lagunitas Creek, Arroyo Corte Madera Creek, Miller Creek, etc.
(2) Including Sulphur Springs Creek, Laurel Creek, Mt. Diablo Creek, etc.
(3) Including Rodeo Creek, Cordonices Creek, Claremont Creek, Peralta Creek, Lake Merritt, etc.
(4) Including Stevens Creek, Permanente Creek, Saratoga Creek, etc.
(5) Including Cordilleras Creek, Colma Creek, Pilarcitos Creek, Pescadero Creek, San Gregorio Creek, etc.

The most prominent surface water body in the Bay Region is San Francisco Bay itself. Other surface water bodies include: creeks and rivers; ocean bays and lagoons (such as Bolinas Bay and Lagoon, Half Moon Bay, and Tomales Bay); urban lakes (such as Lake Merced and Lake Merritt); and human-made lakes and reservoirs (such as Lafayette Reservoir, Briones Reservoir, Calaveras Reservoir, Crystal Springs Reservoir, Kent Lake, Lake Chabot, Lake Hennessey, Nicasio Reservoir, San Andreas Lake, San Antonio Reservoir, San Pablo Reservoir, Upper San Leandro Reservoir, Anderson Reservoir, and Lake Del Valle).

3.5.1.2 Groundwater

A groundwater basin is an area underlain by permeable materials capable of storing a significant amount of water. Groundwater basins are closely linked to local surface waters. As water flows from the hills toward the Bay, it percolates through permeable soils into the groundwater basins. The nine-county Bay Area contains a total of 28 groundwater basins. The ten primary groundwater basins are the Petaluma Valley, Sonoma Valley, Suisun-Fairfield Valley, San Joaquin Valley, Clayton Valley, Diablo Valley, San Ramon Valley, Livermore Valley, and Santa Clara Valley basins. Groundwater in the Bay Area is used for numerous purposes, including municipal and industrial water supply; however, groundwater use accounts for only about five percent of the total water usage.

3.5.1.3 Water Quality

The San Francisco Bay Regional Water Quality Control Board (SFBRWQCB) is the lead agency charged with protecting and enhancing surface water and groundwater quality in the Bay Area. SFBRWQCB implements the Total Maximum Daily Load (TMDL) Program, which involves determining a safe level of loading for each problem pollutant, determining the pollutant sources, allocating loads to all of the sources, and implementing the load allocations. SFBRWQCB is taking a watershed management approach to runoff source issues, including TMDL implementation, by engaging all affected stakeholders in designing and implementing goals on a watershed basis to protect water quality.

The SFBRWQCB monitors pollutants through its Regional Monitoring Program; develops management strategies; and implements actions, including pollution prevention. San Francisco Bay and a number of the streams, lakes, and reservoirs in the Bay Region have elevated mercury levels, as indicated by elevated mercury levels in fish tissue. The major source of the mercury is local mercury mining and mining activities in the Sierra Nevada and coastal mountains. Large amounts of contaminated sediments were discharged into the Bay from Central Valley streams and local mines in the region. Significant impaired water bodies include the Bay, the Guadalupe River in Santa Clara County (from New Almaden Mine), and Walker Creek in Marin County (from Gambonini Mine). Consequently, the SFBRWQCB has adopted TMDLs for mercury in the Bay, Guadalupe River, and Walker Creek. Wastewater treatment plants and urban runoff also are a source of mercury, and some wetlands may contain significant amounts of methylmercury (the bioavailable form of mercury in the aquatic environment) from contaminated sediments (DWR, 2013a).

San Francisco Bay is a nutrient-enriched (nitrogen and phosphorus) estuary, but has not suffered from some of the problems found in other similar estuaries with high nutrient concentrations. Dissolved oxygen concentrations in the Bay's subtidal habitats are much higher, and phytoplankton levels are substantially lower than expected in an estuary with such high nutrient enrichment. The phytoplankton growth is limited by strong tidal mixing, reduced sunlight due to high turbidity, and grazing clams (DWR, 2013a).

Since the late 1990s, the Bay has experienced significant increases in phytoplankton biomass from Suisun Bay to the South Bay (30 to 105 percent) and significant declines in dissolved oxygen concentrations (2 to 4 percent). Also, cyanobacteria and dinoflagellate (red tide) blooms are occurring in portions of the bay. The SFBRWQCB is working collaboratively with stakeholders to evaluate the impacts of nutrients on water quality and to develop a regional nutrient management strategy (DWR, 2013a).

The rate and timing of freshwater inflows are among the most important factors influencing the physical, chemical, and biological conditions in San Francisco Bay. Retaining adequate freshwater inflows to the Bay is critical to protect migrating fish and estuarine habitat. Adequate inflows are necessary to control salinity, to maintain proper water temperature, and to flush out residual pollutants that cannot be eliminated by treatment or source management.

The Sacramento and San Joaquin Rivers flow into the eastern end of Suisun Bay, contributing most of the freshwater inflows to the bay. Many small rivers and streams also contribute fresh water. Much of the fresh water is impounded by upstream dams and is diverted to various water projects, which provide vital water to industries, farms, homes, and businesses throughout the state. The SFBRWQCB, the Central Valley Regional Water Quality Control Board, the SWRCB, and other stakeholders are working to improve Bay water quality by finding solutions to complex diversion issues. These agencies have formed the Bay-Delta Team to implement a long-term program that addresses impacts to beneficial uses of water in the bay and the Delta (DWR, 2013a).

Another water quality issue in the Bay Region is from stream channel erosion. An excess of sediment can be conveyed downstream, which leads to loss of riparian habitat and loss of spawning habitat for native salmonids. Stream erosion is accelerated by urbanization and additional impervious surfaces, land use conversion, rural development, and grazing. Many watersheds in the region are impaired by excessive sedimentation, a lack of large woody debris, and a lack of spawning gravels. The SFBRWQCB addresses these issues through its stormwater program, which regulates construction activities and controls erosion from developments; through working with flood control agencies on stream maintenance; and through its TMDL program, which sets load limits for discharge from sources such as roads, confined animal facilities, vineyards, and grazing lands. The SFBRWQCB also directs technical assistance and grant funding to locally managed watershed programs working on restoration projects and education and outreach efforts (DWR, 2013a).

3.5.1.4 Water Supply and Demand

The following water agencies serve the majority of the water demands in the Bay Area Region:

- Alameda County Water District (ACWD)
- Bay Area Water Supply and Conservation Agency (BAWSCA)
- Contra Costa Water District (CCWD)
- East Bay Municipal Utility District (EBMUD)
- Marin Municipal Water District (MMWD)
- City of Napa Water Department
- San Francisco Public Utilities Commission (SFPUC)
- Santa Clara Valley Water District (SCVWD)
- Solano County Water Agency (Solano CWA)
- Sonoma County Water Agency (Sonoma CW)
- Zone 7 Water Agency (Zone 7)

The Bay Area relies on imported water, local surface water, and groundwater for water supply. Local supplies account for about 30 percent of the total, and the remaining supply is imported from the State Water Project (SWP), Central Valley Project (CVP), and the Mokelumne and Tuolumne watersheds. In 2010, demand in the region was 1,278,480 acre-feet per year (af/yr)[1]. Demand is projected to grow to 1,680,963 af/yr in a normal year, and 1,666,870 af/yr in a single dry year by 2035 (see Table 3.5-1) (DWR, 2013a).

Some water agencies in the region have imported water from the Sierra Nevada for nearly a century to supply customers. EBMUD and SFPUC import surface water into the Bay Region from the Mokelumne and Tuolumne rivers via the Mokelumne and Hetch Hetchy aqueducts, respectively. Water from these two rivers accounts for approximately 38 percent of the average annual water supply in the Bay Area. Water from the Sacramento-San Joaquin Delta (Delta), via the federal CVP and the SWP, accounts for another 28 percent. Approximately 31 percent of the average annual water supply in the Bay Area comes from local groundwater and surface water; and three percent is from miscellaneous sources such as harvested rainwater, recycled water, and transferred water. Reservoirs in the region capture runoff to augment local water supplies and to recharge aquifers. Some reservoirs store water at the terminus of constructed aqueducts, such as the Santa Clara Terminal Reservoir at the terminus of the South Bay Aqueduct.

Many Bay Region residents get their water from local streams. In the South Bay, local streams supply water to the SFPUC, San Jose and other cities in Santa Clara County, cities in Alameda County, and to small developments in the surrounding mountains. The Alameda County Water District, Zone 7 Water Agency (Zone 7) and SCVWD recharge their groundwater basins with local streams, as well as with deliveries from the SWP and the CVP. Local streams also play a large role in the North Bay, providing a majority of the water supply for Marin and Napa counties. Population growth and diminishing water supply and water quality have led to the development of local surface water supplies, recharge of groundwater basins, and incorporation of conservation guidelines to sustain water supply and water quality for future generations (DWR, 2013a).

Bay Area water agencies manage a diverse portfolio of water supplies, including groundwater, local surface water, Sierra Nevada water from the Mokelumne and Tuolumne rivers, Delta water from the SWP and the CVP, and recycled water. San Francisco Public Utilities Commission (SFPUC), East Bay Municipal Utility District (EBMUD), and Santa Clara Valley Water District (SCVWD) have critical water interties to deliver water between water systems during emergencies such as earthquakes and wildfires. SWP contractors and DWR established the Monterey Agreement in 1994 to improve water management flexibility and increase the reliability of SWP deliveries during periods of water shortage (DWR, 2013a).

Historically, the Bay Area has experienced a significant increase in population with a minimal associated change in total water use. The Water Conservation Bill of 2009, or SBX7-7, provides the regulatory framework to support the statewide reduction in urban per capita water use. Each water retailer was required to determine and report its existing baseline water consumption and establish an interim target in their 2015 Urban Water Management Plan (UWMP) and a 2020

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[1] One acre-foot of water is equal to approximately 325,851 gallons.

water use target in. Although water wholesalers are not required to meet the targets outlined in SBX7-7, many Bay Area wholesalers implement conservation programs and policies both to ensure compliance with SBX7-7 and to ensure that long-term water supply reliability goals are met (San Francisco Bay Area IRWMP, 2013).

These demand management measures, combined with alternative resources and strategies, and regulatory requirements, are expected to allow Bay Area water agencies to continue to meet projected demand through 2035 in average years. However, in dry years all but four major agencies (Marin Municipal Water District, City of Napa, SFPUC and Zone 7) project a shortfall. Without strong local and regional planning, most Bay Area Region water agencies could experience future supply shortfalls in severe droughts. Supplies and demands of the Bay Area Region are summarized in Table 3.5-2 below and show that supplies are adequate through 2035 except in dry year scenarios, in which a shortfall is projected (San Francisco Bay Area IRWMP, 2013).

TABLE 3.5-2
Summary of Bay Area Region Water Supply and Demand

		Projected				
	Current	**Normal Year**		**Single Dry Year**		**Multiple Dry Year**
	2010	2020	2035	2020	2035	Worst Case
Population(1)	7,331,716	8,231,905	9,186,676	8,231,905	9,186,676	
Supply (AFY)	1,475,595	1,719,535	1,793,699	1,522,959	1,563,757	1,073,975
Demand (AFY)	1,278,480	1,534,534	1,680,963	1,517,778	1,666,870	1,197,143
Difference (AFY)	197,115	185,001	112,736	5,181	-103,113	-123,168

Source: IRWMP, 2013
Note: (1) Does not include Sonoma CWA

3.5.1.5 Drinking Water Quality

Drinking water in the Bay Region ranges from high-quality Mokelumne and Tuolumne River water to variable-quality Delta water, which constitutes about one-third of the domestic water supply. Purveyors that depend on the Delta for all or part of their domestic water supply can meet drinking water standards, but still need to be concerned about microbial contamination, salinity, and organic carbon.

In 2013, the SWRCB completed a statewide report titled, “Communities that Rely on a Contaminated Groundwater Source for Drinking Water.” The report identified contaminated wells statewide that exceed a primary drinking water standard prior to any treatment or blending. In the Bay Region, 28 contaminated wells were identified that are used by 18 water systems. Most of the affected drinking water systems are small and often need financial assistance to construct a water treatment plant or another facility to meet drinking water standards. The most prevalent contaminants in the region are arsenic, nitrate, and aluminum (DWR, 2013a).

3.5.1.6 Recycled Water

In the 1990s, a number of local agencies joined with the DWR and the United States Bureau of Water Reclamation to study the feasibility of using high-quality recycled water to augment water supplies and help the Bay-Delta ecosystem. This cooperative effort, known as the Bay Area Regional Water Recycling Program (BARWRP), produced a Master Plan for regional water recycling in 1999 for the five South Bay counties. Since then, local water agencies have built a number of projects consistent with BARWRP, and recycled water has come to be widely used in the Bay Area for a number of applications, including landscape irrigation, agricultural needs, commercial and industrial purposes, and as a supply to the area's wetlands. The 2006 Bay Area Integrated Regional Water Management Plan (IRWMP) identified 43 potential recycled water projects that could be implemented by the year 2020 (ABAG, 2013). The potential market for recycled water is estimated to be 240,000 acre-feet per year by 2025. The region increased its recycled water use over 36 percent, from 29,500 af in 2001 to 40,300 af in 2009 (DWR, 2013a). The largest use of recycled water is for landscape irrigation, including golf courses, wetlands, industrial uses, and agricultural irrigation.

3.5.1.7 Wastewater Treatment

Wastewater is generated by residential, commercial and industrial sources throughout the Bay Area. The Clean Water Act requires treatment of wastewater for the protection of human health and receiving water bodies and preservation of the health of aquatic and riparian species. Wastewater treatment facilities consist of staged processes with the specific treatment systems authorized through NPDES permits. Primary treatment generally consists of initial screening and clarifying. Primary clarifiers are large pools where solids in wastewater are allowed to settle out. The clarified water is pumped into secondary clarifiers and the screenings and solids are collected, processed through large digesters to break down organic contents, dried and pressed, and either disposed of in landfills or used for beneficial agricultural applications. Secondary clarifiers repeat the process of the primary clarifiers further, refining the effluent.

Other means of secondary treatment include flocculation (adding chemicals to precipitate solids removal) and aeration (adding oxygen to accelerate breakdown of dissolved constituents). Tertiary treatment involves the removal of nutrients and nearly all suspended organic matter from wastewater, and may consist of filtration, disinfection, and reverse osmosis technologies. Chemicals are added to the wastewater during the primary and secondary treatment processes to accelerate the removal of solids and to reduce odors. Chlorine is often added to eliminate pathogens during final treatment, and sulfur dioxide is often added to remove the residual chlorine. Methane produced by the treatment processes can be used as fuel for the plant's engines and electricity needs. Recycled water must receive a minimum of tertiary treatment in compliance with DHS regulations. Water used to recharge potable groundwater supplies generally receives reverse osmosis and microfiltration prior to reuse.

Wastewater treatment in the Bay Area is provided by various agencies as well as individual city and town wastewater treatments. Treated wastewater is generally discharged into a water body, evaporation pond or percolation basin, or used recycled for agriculture, irrigation or landscaping. The U.S. EPA's NPDES permit program affects how a municipality handles its sanitary wastewater. Tertiary treatment is now commonly required for discharges to bodies of water, particularly where there is potential for human contact. Properly managed wastewater treatment systems play an important role in protecting community health and local water quality

3.5.2 REGULATORY SETTING

There are a variety of overlapping federal, state and local regulations that regulate water resources and water quality. A number of federal regulations (e.g., the Clean Water Act) are primarily implemented by state agencies with oversight from the U.S. EPA. This section summarizes the more pertinent federal, state and local regulations on water resources.

3.5.2.1 Federal Regulations

3.5.2.1.1 Clean Water Act

The Clean Water Act (CWA) establishes the basic structure for regulating discharges of pollutants into "waters of the United States." The Act specifies a variety of regulatory and non-regulatory tools to sharply reduce direct pollutant discharges into waterways, finance municipal wastewater treatment facilities, and manage polluted runoff. Some of these tools include:

- Section 303(d) – Total Maximum Daily Loads (TMDLs);
- Section 401 – Water Quality Certification;
- Section 402 – National Pollutant Discharge Elimination System (NPDES) Program; and.
- Section 404 – Discharge of Dredge or Fill Material.

Section 303(d) – Total Maximum Daily Loads (TMDLs): The CWA §303(d) requires the SWRCB to prepare a list of impaired water bodies in the state and determine total maximum daily loads (TMDLs) for pollutants or other stressors impacting water quality of these impaired water bodies. A TMDL is a quantitative assessment of water quality conditions, contributing sources, and the load reductions or control actions needed to restore and protect bodies of water in order to meet their beneficial uses. All sources of the pollutants that caused each body of water to be included on the list, including point sources and non-point sources, must be identified. The California §303 (d) list was completed in March 1999. On July 25, 2003, U.S. EPA gave final approval to California's 2002 revision of §303 (d) List of Water Quality Limited Segments. A priority schedule has been developed to determine TMDLs for impaired waterways. TMDL projects are in various stages throughout the District for most of the identified impaired water bodies. The Regional Water Quality Control Boards are responsible for ensuring that total discharges do not exceed TMDLs for individual water bodies as well as for entire watersheds.

Section 401 – Water Quality Certification: The RWQCBs coordinate the State Water Quality Certification program, or CWA §401. Under CWA §401, states have the authority to review any federal permit or license that will result in a discharge or disruption to wetlands and other waters under state jurisdiction to ensure that the actions will be consistent with the state's water quality requirements. This program is most often associated with CWA §404 which obligates the U.S. Army Corps of Engineers to issue permits for the movement of dredge and fill material into and from "waters of the United States".

Section 402 – National Pollutant Discharge Elimination System (NPDES) Program: Section 402: Section 402 regulates point-source discharges to surface waters through the National Pollutant Discharge Elimination System (NPDES) program. In California, the State Water Resources Control Board (State Water Board or SWRCB) oversees the NPDES program, which is administered by the RWQCBs. The NPDES program provides for both general permits (those that cover a number of similar or related activities) and individual permits. The NPDES program covers municipalities, industrial activities, and construction activities. The NPDES program includes an industrial stormwater permitting component that covers ten categories of industrial activity that require authorization under an NPDES industrial stormwater permit for stormwater discharges. The NPDES permit establishes discharge pollutant thresholds and operational conditions for industrial facilities and wastewater treatment plants. For point source discharges (e.g., wastewater treatment facilities), the RWQCBs prepare specific effluent limitations for constituents of concern such as toxic substances, total suspended solids (TSS), bio-chemical oxygen demand (BOD), and organic compounds.

Construction activities, also administered by the State Water Board, are discussed below under state regulations. Section 402(p) of the federal Clean Water Act, as amended by the Water Quality Act of 1987, requires NPDES permits for stormwater discharges from municipal separate storm sewer systems (MS4s), stormwater discharges associated with industrial activity (including construction activities), and designated stormwater discharges, which are considered significant contributors of pollutants to waters of the United States. On November 16, 1990, U.S. EPA published regulations (40 CFR Part 122), which prescribe permit application requirements for MS4s pursuant to CWA 402(p). On May 17, 1996, U.S. EPA published an Interpretive Policy Memorandum on Reapplication Requirements for Municipal Separate Storm Sewer Systems, which provided guidance on permit application requirements for regulated MS4s. MS4 permits include requirements for post-construction control of stormwater runoff in what is known as Provision C.3. The goal of Provision C.3 is for the Permittees to use their planning authorities to include appropriate source control, site design, and stormwater treatment measures in new development and redevelopment projects to address both soluble and insoluble stormwater runoff pollutant discharges and prevent increases in runoff flows from new development and redevelopment projects. This goal is to be accomplished primarily through the implementation of low impact development (LID) techniques.

3.5.2.1.2 Safe Water Drinking Act (SDWA)

Passed in 1974 and amended in 1986 and 1996, the SDWA gives the U.S. EPA the authority to set drinking water standards. Drinking water standards apply to public water systems, which provide water for human consumption through at least 15 service connections, or regularly serve at least 25 individuals. There are two categories of drinking water standards, the National Primary Drinking Water Regulations (NPDWR) and the National Secondary Drinking Water Regulations (NSDWR). The NPDWR are legally enforceable standards that apply to public water systems. NPDWR standards protect drinking water quality by limiting the levels of specific contaminants that can adversely affect public health and are known or anticipated to occur in water.

3.5.2.1.2 Section 10 of the Rivers and Harbors Act

Section 10 of the Rivers and Harbors Act, administered by United States Army Corp of Engineers (U.S. ACE), requires permits for all structures (such as riprap) and activities (such as dredging) in navigable waters of the U.S.

3.5.2.1.3 Executive Order 11990 – Protection of Wetlands

Executive Order 11990 is an overall wetlands policy for all agencies managing federal lands, sponsoring federal projects, or providing federal funds to state or local projects. Executive Order 11990 requires that when a construction project involves wetlands, a finding must be made by the federal agency that there is no practicable alternative to such construction, and that the proposed action includes all practicable measures to minimize impacts to wetlands resulting from such use.

3.5.2.1.4 Executive Order 11988 – Floodplain Management

Executive Order 11988 directs federal agencies to avoid to the extent practicable and feasible short- and long-term adverse impacts associated with the occupancy and modification of floodplains and to avoid direct and indirect support of floodplain development wherever there is a practicable alternative. Further, Executive Order 11988 requires the prevention of uneconomic, hazardous, or incompatible use of floodplains; protection and preservation of the natural and beneficial floodplain values; and consistency with the standards and criteria of the National Flood Insurance Program (NFIP).

3.5.2.1.5 National Flood Insurance Act

The U.S. Congress passed the National Flood Insurance Act (NFIA) in 1968 and the Flood Disaster Protection Act in 1973 to restrict certain types of development on floodplains and to provide for a national flood insurance program (NFIP). The purpose of these acts is to reduce the need for large, publicly funded flood control structures and disaster relief. The NFIP is a federal program administered by the Flood Insurance Administration of FEMA. It enables individuals who have property (a building or its contents) within the 100-year floodplain to purchase insurance against flood losses. Community participation and eligibility, flood hazard identification, mapping, and floodplain management aspects are administered by state and local programs and support directorate within FEMA. FEMA works with the states and local communities to identify flood hazard areas and publishes a flood hazard boundary map of those areas. Floodplain mapping is an ongoing process in the Bay Area and flood maps must be regularly updated for both major rivers and tributaries as land uses and development patterns change.

3.5.2.2 State Regulations

3.5.2.2.1 Porter-Cologne Water Quality Control Act

The Porter-Cologne Water Quality Control Act established the State Water Resources Control Board and divided the state into nine regions, each overseen by a RWQCB. The nine regional boards have the primary responsibility for the coordination and control of water quality within their respective jurisdictional boundaries. Under the Porter-Cologne Water Quality Control Act, water quality objectives are limits or levels of water quality constituents or characteristics established for the purpose of protecting beneficial uses. The Act requires the RWQCBs to establish water quality objectives while acknowledging that water quality may be changed to some degree without unreasonably affecting beneficial uses. Designated beneficial uses, together with the corresponding water quality objectives, also constitute water quality standards under the federal Clean Water Act. Therefore, the water quality objectives form the regulatory references for meeting state and federal requirements for water quality control.

Each RWQCB is required to prepare and update a Basin Plan for their jurisdictional area. Pursuant to the CWA NPDES program, the RWQCB also issues permits for point source discharges that must meet the water quality objectives and must protect the beneficial uses defined in the Basin Plan.

3.5.2.2.2 Construction General Permit

The California Construction Stormwater Permit (Construction General Permit), adopted by the State Water Resources Control Board, regulates construction activities that include clearing, grading, and excavation resulting in soil disturbance of at least one acre of total land area. Individual storm water NPDES permits are required for specific industrial activities and for construction sites greater than five acres. Statewide general storm water NPDES permits have been developed to expedite discharge applications. They include the statewide industrial permit and the statewide construction permit. A prospective applicant may apply for coverage under one of these permits and receive Waste Discharge Requirements (WDRs) from the appropriate RWQCB. WDRs establish the permit conditions for individual dischargers. The Stormwater Rule automatically designates, as small construction activity under the NPDES stormwater permitting program, all operators of construction site activities that result in a land disturbance of equal to or greater than one and less than five acres. Site activities that disturb less than one acre are also regulated as small construction activity if they are part of a larger common plan of development or sale with a planned disturbance of equal to or greater than one acre and less than five acres, or if they are designated by the NPDES permitting authority. The NPDES permitting authority or U.S. EPA Region may designate construction activities disturbing less than one acre based on the potential for contribution to a violation of a water quality standard or for significant contribution of pollutants to waters of the United States.

The Construction General Permit authorizes the discharge of stormwater to surface waters from construction activities. The Construction General Permit requires that all developers of land where construction activities will occur over more than one acre to develop and implement a Stormwater Pollution Prevention Plan (SWPPP), which specifies Best Management Practices (BMPs) that will reduce pollution in stormwater discharges to the Best Available Technology Economically Achievable/Best Conventional Pollutant Control Technology standards; and, perform inspections and maintenance of all BMPs. Typical BMPs contained in SWPPPs are designed to minimize erosion during construction, stabilize construction areas, control sediment, control pollutants from construction materials, and address post construction runoff quantity (volume) and quality (treatment). The SWPPP must also include a discussion of the program to inspect and maintain all BMPs.

3.5.2.2.3 Drinking Water Standards

The California Safe Drinking Water Act, enacted in 1976, is codified in Title 22 of the CCR. The California Safe Drinking Water Act provides for the operation of public water systems and imposes various duties and responsibilities for the regulation and control of drinking water in the State of California including enforcing provisions of the federal Safe Drinking Water Act. The California Safe Drinking Water Program was originally implemented by the California Department of Public Health until July 1, 2014 when the program was transferred to the SWRCB via an act of legislation, SB 861. This transfer of authority means that the SWRCB has regulatory and enforcement authority over drinking water standards and water systems under Health and Safety Code §116271.

Potable water supply is managed through the following agencies and water districts: the California Department of Water Resources (DWR), the California Department of Health Services (DHS), the SWRCB, the U.S. EPA, and the U.S. Bureau of Reclamation. Water right applications are processed through the SWRCB for properties claiming riparian rights. The DWR manages the State Water Project (SWP) and compiles planning information on water supply and water demand within the state. Primary drinking water standards are promulgated in the CWA §304 and these standards require states to ensure that potable water retailed to the public meets these standards. Standards for a total of 88 individual constituents, referred to as Maximum Contaminant Levels (MCLs), have been established under the Safe Drinking Water Act as amended in 1986 and 1996. The U.S. EPA may add additional constituents in the future. The MCL is the concentration that is not anticipated to produce adverse health effects after a lifetime of exposure. State primary and secondary drinking water standards are codified in CCR Title 22 §§64431 - 64501. Secondary drinking water standards incorporate non-health risk factors including taste, odor, and appearance. The 1991 Water Recycling Act established water recycling as a priority in California. The Water Recycling Act encourages municipal wastewater treatment districts to implement recycling programs to reduce local water demands. The DHS enforces drinking water standards in California.

3.5.2.2.4 California Department of Fish and Wildlife

The California Department of Fish and Wildlife is responsible for conserving, protecting, and managing California's fish, wildlife, and native plant resources. To meet this responsibility, the Fish and Game Code (Section 1602) requires an entity to notify the Department of any proposed activity that may substantially modify a river, stream, or lake. The notification requirement applies to any work undertaken in or near a river, stream, or lake that flows at least intermittently through a bed or channel. This includes ephemeral streams, desert washes, and watercourses with a subsurface flow. It may also apply to work undertaken within the flood plain of a body of water.

3.5.2.2.5 Wastewater Treatment Regulations

The federal government enacted the CWA to regulate point source water pollutants, particularly municipal sewage and industrial discharges, to waters of the United States through the NPDES permitting program. In addition to establishing a framework for regulating water quality, the CWA authorized a multibillion dollar Clean Water Grant Program, which together with the California Clean Water Bond funding, assisted communities in constructing municipal wastewater treatment facilities. These financing measures made higher levels of wastewater treatment possible for both large and small communities throughout California, significantly improving the quality of receiving waters statewide. Wastewater treatment and water pollution control laws in California are codified in the CWC and CCR, Titles 22 and 23. In addition to federal and state restrictions on wastewater discharges, most incorporated cities in California have adopted local ordinances for wastewater treatment facilities. Local ordinances generally require treatment system designs to be reviewed and approved by the local agency prior to construction. Larger urban areas with elaborate infrastructure in place would generally prefer new developments to hook into the existing system rather than construct new wastewater treatment facilities. Other communities promote individual septic systems to avoid construction of potentially growth accommodating treatment facilities. The RWQCBs generally delegate management responsibilities of septic systems to local jurisdictions. Regulation of wastewater treatment includes the disposal and reuse of biosolids.

3.5.2.3 Local Regulations

3.5.2.3.1 McAteer-Petris Act/San Francisco Bay Conservation and Development Commission

The McAteer-Petris Act is a provision under California law that preserves San Francisco Bay from indiscriminate filling. The Act established the San Francisco Bay Conservation and Development Commission (BCDC) as the agency charged with preparing a plan for the long-term use of the Bay and regulating development in and around the Bay while the plan was being prepared. The San Francisco Bay Plan, completed in January 1969, includes policies on 18 issues critical to the wise use of the bay, ranging from ports and public access to design considerations and weather. The McAteer-Petris Act authorizes BCDC to incorporate the policies of the Bay Plan into state law. The Bay Plan has two features: policies to guide future uses of the bay and shoreline, and maps that apply these policies to the bay and shoreline. BCDC conducts the regulatory process in accordance with the Bay Plan policies and maps, which guide the protection and development of the bay and its tributary waterways, marshes, managed wetlands, salt ponds, and shoreline.

3.5.2.3.2 General Plan Safety Elements

Government Code §65302, as amended (2007 Cal. Stat. 369) requires that on or after January 1, 2009, the updated safety elements of general plans must incorporate significantly enhanced geographic data, goals, and policies related to flood hazards. This enhanced assessment of flood hazards will include, but is not limited to: flood mapping information from multiple agencies including FEMA, the Army Corps of Engineers, the Office of Emergency Services, the Department of Water Resources, and any applicable regional dam, levee, or flood protection agencies; historical data on flooding; an inventory of existing and planned development (including transportation infrastructure) in flood zones; and new policies that comprehensively address existing and future flood risk in the planning area.

3.5.2.3.3 Other Local Regulations

In addition to federal and state regulations, cities, counties and water districts may also provide regulatory advisement regarding water resources. Many jurisdictions incorporate policies related to water resources in their municipal codes, development standards, storm water pollution prevention requirements, and other regulations.

3.5.3 SIGNIFICANCE CRITERIA

The proposed project impacts on hydrology and water quality would be considered significant if the following occurs:

Water Demand:

- The existing water supply does not have the capacity to meet the increased demands of the project, or the project would use more than 262,820 gallons per day of potable water.

Water Quality:

- The project will cause degradation or depletion of ground water resources substantially affecting current or future uses.
- The project will cause the degradation of surface water substantially affecting current or future uses.
- The project will result in a violation of NPDES permit requirements.

- The capacities of existing or proposed wastewater treatment facilities and the sanitary sewer system are not sufficient to meet the needs of the project.

3.5.4 ENVIRONMENTAL IMPACTS

As discussed previously, the NOP/IS (see Appendix A) determined that the water demand and water quality impacts associated with implementation of proposed Rule~~s 11-18 and~~ 12-16 was ~~were~~ potentially significant and would be evaluated further in the EIR. Implementation of Rule~~s 11-18 and~~ 12-16 could require more facilities to install new or modify their existing air pollution control equipment. ~~Under Rule 11-18, if facilities exceed certain health risk limits, they would be required to make modifications to reduce the health risk associated with the facility which could include facility modifications, changes in operation, and/or modifications to existing or installation of new air pollution control equipment.~~ Additional water demand and wastewater generation impacts are expected to result from the operation of several of the possible control technologies that would most likely be used (see Table 3.5-3).

3.5.4.1 Potential Water Demand Impacts

~~Rule 11-18~~

~~If any stationary sources are shown to exceed threshold limits for toxic air contaminants, it is expected that facility operators could install new, or modify their existing air pollution control equipment in order to reduce TAC emissions under Regulation 11-18. Most air pollution control equipment does not use water or generate wastewater (see Table 3.5-1). However, additional water demand and wastewater generation impacts are expected to result from the operation of wet gas scrubbers which may be used for control of particulate TAC emissions (see Table 3.5-1).~~

Rule 12-16

If any refineries are shown to exceed the refinery-wide emissions limits for $PM_{2.5}$, PM_{10}, NOx or SO_2, it is expected that refinery operators would install new, or modify their existing air pollution control equipment in order to reduce emissions as required by Regulation 12-16. Additional water demand and wastewater generation impacts are expected to result from the operation of several of the possible control technologies that would most likely be used including wet electrostatic precipitators (ESPs) and wet gas scrubbers (see Table 3.5-3).

TABLE 3.5-3

Potential Control Technologies and Potential Water Use and Wastewater Generation During Equipment Operations

Applicable Rule	Potential Control Technology	Uses Water?	Exceeds Threshold?	Generates Wastewater?	Exceeds Threshold?
~~11-18 &~~12-16	Baghouse with HEPA Filters	No	No	No	No
~~11-18~~	~~Carbon Adsorption~~	~~No~~	~~No~~	~~No~~	~~No~~
12-16	Compressor	No	No	No	No
12-16	Cyclone	No	No	No	No
~~11-18 &~~ 12-16	Diesel Oxidation Catalyst	No	No	No	No
~~11-18 &~~ 12-16	Diesel Particulate Filter	No	No	No	No
12-16	Electrostatic Precipitator (Dry)	No	No	No	No
12-16	Electrostatic Precipitator (Wet)	Yes	No	Yes	No
12-16	Flue Gas Treatment (Additive to Existing Amine System)	No	No	No	No
12-16	Flue Gas Treatment (Merox Treatment)	No	No	No	No
12-16	LoTOx (see WGS)	~~No~~	~~No~~		
~~11-18 &~~ 12-16	New Diesel ICEs	No	No	No	No
12-16	Selective Catalytic Reduction	No	No	No	No
12-16	Selective Oxidation Catalyst	No	No	No	No
12-16	Steam Ejector Technology	No	No	No	No
12-16	SOx Reducing Additive	No	No	No	No
~~11-18~~	~~Thermal Oxidizer~~	~~No~~	~~No~~	~~No~~	~~No~~
12-16	Ultracat	No	No	No	No
~~11-18 &~~ 12-16	Wet Gas Scrubber	Yes	Yes	Yes	No

It is difficult to project water demand impacts from control equipment for the following reasons. It is necessary to know the desired level of control to sufficiently reduce pollutant concentrations as appropriate. This in turn will determine the number of industrial facilities or refinery units that would need to be retrofitted with air pollution control equipment. It also necessary to know the size of the facilities/refinery unit, which affects exhaust flow rate calculated as dry cubic feet per minute at standard conditions, another necessary variable used to calculate water demand. To maintain fresh solution, fresh water must be added periodically using either sump overflow or blowdown. In the sump overflow method fresh water is added through an adjustable flow meter at a continuous rate while the sump liquid overflows into the scrubber drain at a predetermined location. In the blowdown method, liquid is forced to drain by the recirculation pump. Regardless of the replenishing method used, it is necessary to know the flow rate necessary to maintain fresh solution. The rate of evaporation from the system must also be factored into the calculation of water demand impacts, which, at a minimum, requires knowing the operating temperature and humidity. All of these factors require precise data from each facility operator for each piece of equipment, which is currently not available.

Demolition and construction activities to install air pollution control equipment have the potential to generate potential water demand and water quality impacts. For example, water is used during construction to reduce fugitive dust from any site preparation or grading activities. Potential water demand and water quality impacts during potential future construction activities will be evaluated in the subsections below.

Table 3.5-3 shows air pollution control equipment that would provide the best opportunities for obtaining further emission reductions emissions from stationary sources that would be regulated by Rule~~s 11-18 and/or~~ 12-16. As shown in Table 3.5-3, not all control technologies use water as part of the emission control process and, therefore, would not be expected to contribute to water demand or water quality impacts. These control technologies will not be considered further in this analysis. Analyses of water demand and water quality impacts from control equipment that do use water as part of the control process are provided in the following subsections.

3.5.4.1.1 Dust Suppression Associated with Construction Activities

Installation of some types of relatively small air pollution control equipment, e.g., equipment, compressors, diesel oxidation catalysts, diesel particulate filters, and steam ejectors are not expected to require site preparation activities because the equipment is generally not very large and could often be constructed onto existing foundations. In the event that some site preparation is necessary for these types of control technologies, plots would be small in area, thus, requiring little water for fugitive dust control. Therefore, little or no water for dust suppression purposes is expected to be needed for construction of compressors, diesel oxidation catalysts, and diesel particulate filters, or the replacement of diesel ICEs with new diesel ICEs.

For large air pollution control equipment, e.g., ESPs, FGTs, WGSs, etc., site preparation activities requiring water for dust control would likely be necessary for relatively larger areas compared to compressors, diesel oxidation catalysts, diesel particulate filters, and steam ejectors. For example, it is assumed that one water truck per affected facility may be needed for dust suppression activities during the initial site preparation/earth moving to install large air pollution control equipment. One water truck used for dust control can hold approximately 6,000 gallons and it can be refilled over the course of the day if more than 6,000 gallons is needed. If one FGT unit (one of the largest types of potential air pollution control equipment that could be installed in response to ~~future Regulation 11-18 or~~ Regulation 12-16 emission reduction requirements), a typical system could require an area of approximately 6,000 square feet. By applying one gallon of water per square foot of disturbed area, at a minimum of two times per day to minimize fugitive dust, the total amount of water expected to be used for dust suppression is approximately 12,000 gallons per day for each affected facility. On windy days, it may be necessary to conduct a third water application. Thus, the total peak amount of water that could be used for dust suppression is approximately 18,000 gallons per facility per day. This analysis assumes that all water used for dust suppression activities is potable water. It is likely that some affected facilities have access to reclaimed water supplies, which could be used instead of potable water for dust suppression activities. Finally, once construction is complete, water demand for fugitive dust control activities would cease.

Even if all five affected refineries were to install one FGT with construction and, therefore, dust control activities occurring on the same days water demand for construction (90,000 gallons per day) would not exceed any applicable water demand significance threshold (262,820 gallons per day). Although assuming all five affected refineries would have the same level of fugitive dust control and water demand necessary to control fugitive dust is considered a conservative analysis, it is not likely to occur because other types of air pollution control technologies may be installed instead of FGT, the lengths of time necessary to engineer and construct the equipment, would differ, refinery sites may already be paved, thus, reducing the amount of area necessary for site preparation, etc. ~~The same would be true for industrial facilities subject to Rule 11-18.~~ It is doubtful that five large air pollution control equipment projects would be occurring simultaneously because of the same considerations. Once construction is completed, additional demand for water would end. Therefore, water demand for dust control activities would be much less than 90,000 gallons per day and is concluded to be less than significant.

3.5.4.1.2 Operation

Wet Electrostatic Precipitator – Operation (Rule 12-16)

Installation of wet ESPs may occur under 12-16 and would require additional water, which is used as part of the emission control process. Instead of clean water, it is likely that each affected refinery operator would utilize strip sour water or similar existing treated waste process water from elsewhere within each facility. Because existing sources of refinery wastewater, e.g., strip sour water or similar existing treated wastewater, could be used to operate a wet ESP, demand from installing new add-on control equipment would be minimal. In addition, as discussed in Subsection 3.5.4.2.2 below, wastewater from the wet ESP can be treated and recycled back to the wet ESP, further minimizing water demand impacts. Thus, the impacts of installing a wet ESP to comply with potential future emission reduction requirements pursuant to Regulation 12-16 on future water demand at an affected refinery are not expected to exceed any applicable water demand significance thresholds and, therefore, are concluded to be less than significant.

Wet Gas Scrubber – Operation (Rule~~s 11-18 and~~ 12-16)

A WGS removes SO_2 from the flue gas by using a liquid solution that can be regenerated. As a result, installation of a WGS would result in an increased demand for water at an affected facility. A WGS is one of the control technologies that could be used to remove SO2 or particulate emissions under Rule 12-16~~) and particulates emissions (11-18 and 12-16)~~ from flue gas using a liquid solution that can be regenerated. As a result, installation of a WGS would result in an increased water demand. For example, one wet ESP and one WGS were installed on the FCCU at the Phillips 66 Los Angeles Refinery to control sulfur oxide emissions, as well as PM_{10} and $PM_{2.5}$ emissions. The environmental analysis for this project indicated that the expected water demand associated with the WGS was about 300 gallons per minute (432,000 gallons per day) (SCAQMD, 2007). WGS of this size are primarily designed for large emission sources (e.g., refineries and other large manufacturing facilities), but this technology can also be scaled down for use on smaller sources. The water demand from one new WGS would exceed the CEQA significance threshold for water demand of 262,820 ~~263,000~~ gallons per day and, therefore, is considered to be significant. An estimated three to five WGSs could be installed under Rule 12-16, resulting in a potential increase in water use for up to 2.2 million gallons of water per day.

Conclusion

Based upon the above considerations, water demand impacts from installing most types of air pollution control equipment that use water as part of the control process would not create water demand impacts that exceed the applicable water demand significance thresholds. However, it is likely that water demand impacts from installing a WGS would exceed applicable water demand significance thresholds and, therefore, water demand impacts are concluded to be significant.

3.5.4.2 Potential Water Quality Impacts

Increased demand for water from the various control technologies is limited to control technologies that use water (i.e., wet ESPs and WGS) and will be directly proportional to any increases in wastewater from affected facilities. However, as with quantifying water demand, there is insufficient information available to calculate the volumes of wastewater from control equipment for the following reasons. First, not all of the additional water demand generated by installing air pollution control equipment would ultimately be discharged as wastewater. In addition, some proportion of the increased water demand would be emitted as steam or would evaporate during the control process. To determine the evaporation rate it is necessary to know the operating temperature and humidity in the vicinity of the equipment, which are currently unknown. In addition, wastewater discharge requirements under a facility's Industrial Wastewater Discharge Permit (IWDP) and current wastewater discharge rates need to be known. To the extent possible and based on available information, water quality impacts from air pollution control technologies that use water as part of the control process are evaluated in the following subsections

3.5.4.2.1 Construction Activities

Dust Suppression

Water used for dust suppression activities typically wets the top one to two inches of soil, evaporates and then forms a soil crust. As a result, this water does not flow into storm drains, sewers or other water collection systems and, therefore, water runoff from dust suppression activities would not be expected to occur and water quality impacts from dust suppression activities are concluded to be less than significant.

3.5.4.2.2 Operation

Wet ESPs (Rule 12-16)

As noted above, an IWDP entitles each affected refinery to discharge wastewater. Since additional water would be needed as part of the wet ESP's pollution control process to comply with potential future requirements under Regulation 12-16, the proposed project could increase the wastewater generated by each affected refinery. However, instead of clean water, it is likely that each affected refinery operator would utilize strip sour water or similar existing treated waste process water from elsewhere within each facility.

Wastewater from the wet ESP is collected and flows into a sump where it is typically treated and recycled to minimize water demand and wastewater generated from the equipment. Once recycled, wastewater generated by the wet ESP can also be returned to the wet ESP, which further reduces the total amount of water required for air pollution control, as well as the amount of wastewater discharged into the sewer system. For some types of wet ESPs recirculation of treated water to the ESP may approach 100 percent (U.S. EPA Fact Sheet).

If wastewater from the wet ESP is recycled before being discharged, depending on the volume of the potential wastewater discharged, if it is not within the percent variation allowed by the local sanitation districts, each affected refinery may need to apply for a revision to its IWDP or other wastewater discharge permits to accommodate any additional discharges to the sanitary sewer system. However, because existing sources of refinery wastewater, e.g., strip sour water or similar existing treated waste process water, could be used to operate a wet ESP, additional wastewater generated from installing new add-on control equipment would be minimal. Using existing sources of wastewater could actually result in a net decrease in the amount of wastewater discharged from the affected refinery. Thus, the impacts of installing a wet ESP to comply with potential future emission reduction requirements pursuant to Regulation 12-16 on each affected refinery's wastewater discharge volumes and their IWDPs are not expected to exceed any applicable water quality significance thresholds and, therefore, are concluded to be less than significant.

Wet Gas Scrubber (Rule~~s 11-18 and~~ 12-16)

Water from a WGS can be treated and then recirculated back to the wet gas scrubber to be used again. Depending on a facility's wastewater treatment system, the rest of the effluent may be further treated and discharged to the sanitary sewer system. WGS are most likely to be used on large emission sources such as refinery units, gas turbines or other large industrial facilities that currently have wastewater discharges or wastewater treatment systems. Depending on the type of WGS, some water may be lost as steam. For these reasons, it is not expected that WGS wastewater would exceed a facility's current wastewater discharge limits, require changes to existing wastewater permit conditions, or require new wastewater permits. Refineries are large users of water, have large wastewater discharges, and have large wastewater treatment facilities. Other industrial facilities that would install WGSs would also be expected to be large facilities with existing ISDPs and existing wastewater treatment facilities. Changes to existing permit conditions would not likely be required and no violations of existing IWDPs, NPDES permits, or other wastewater permit limits are expected. Regardless of the facility, wastewater discharges from an industrial facility would be required to be discharged in compliance with applicable wastewater discharge permits. Therefore, water quality impacts from a WGS are not expected to exceed any applicable water quality significance thresholds, so water quality impacts during operation are concluded to be less than significant.

3.5.4.3 Conclusion

Based upon the above considerations, water quality impacts from installing most types of air pollution control equipment that use water as part of the control process would not exceed applicable water quality significance thresholds and, therefore, are concluded to be less than significant.

3.5.5 MITIGATION MEASURES

Because it was concluded that if Wet Gas Scrubbers are installed as a response to Rule 12-16 ~~andor Rule 11-18~~, potential future water demand impacts from the proposed systems during operation would be significant, mitigation measures for water demand are required. Therefore, for any affected refinery that installs an air pollution control technology that increases demand for water, the following water demand mitigation measures will apply.

HWQ-1 When air pollution control equipment is installed and water is required for its operation, the refinery operator is required to use recycled water, if available, to satisfy the water demand for the air pollution control equipment.

HWQ-2 In the event that recycled water cannot be delivered to the affected refinery, the refinery operator is required to submit a written declaration with the application for a Permit to Construct for the air pollution control equipment, to be signed by an official of the water purveyor indicating the reason(s) why recycled water cannot be supplied to the project.

3.5.5.2 Remaining Impacts

Because of the prevalence of drought conditions in Northern California, in spite of implementing the mitigation measures identified above, water demand impacts during operation of the proposed Rule 12-16 remain significant, in part because there is currently no guarantee that reclaimed water will be available to all of the affected facilities. Therefore, the proposed project, Rule 12-16, will remain significant after mitigation for water demand.

With regard to water quality, it was concluded that impacts would be less than significant, so no mitigation measures are required.

~~3.5.6 MITIGATION MONITORING REQUIREMENTS~~

~~Mitigation measures have been proposed to reduce potentially significant water demand impacts. Mitigation monitoring and reporting for measures HWQ-1 and HWQ-2 are described in Table 3.5-2.~~

~~TABLE 3.5-2~~

~~Mitigation Monitoring for Hydrology and Water Quality Impacts~~

~~Proposed Rules 11-18 and 12-16 may have a significant adverse impact on water demand associated with operation of Wet Gas Scrubbers.~~	
~~Mitigation Measure~~	~~HWQ-1: The Air District will require that proof of recycled water use be provided as part of the Authority to Construct application.~~ ~~HWQ-2: The Air District will require that the written declaration that recycled water cannot be used as part of the Authority to Construct application.~~
~~Timing~~	~~Prior to construction~~
~~Methodology~~	~~MM AES-1 will be required in the contract specifications for the WSG cranes.~~ ~~MM AES-2 will be required as an operational control measure.~~
~~Responsible Parties~~	~~Applicant for information required as part of the air permit application.~~ ~~Air District for determination of justification for use or non-use of recycled water.~~
~~Residual Impacts~~	~~Significant after mitigation, as not all sources are expected to use recycled water.~~

3.5.6 CUMULATIVE IMPACTS

In the above analyses of construction water demand and water quality it was concluded that impacts would be less than significant. Similarly, it was concluded that water quality impacts from the proposed project during operation would be less than significant. Therefore, because construction water quality and water demand impacts and operational water quality impacts were concluded to be less than significant, they are not considered to be cumulatively considerable (CEQA Guidelines §15064 (h)(1)) and, therefore are not expected to generate significant adverse cumulative impacts these environmental topic areas.

In the above analysis of water demand impacts from the proposed project during operation it was concluded that installing a WGS has the potential to generate significant adverse operational water demand impacts. Therefore, water demand impacts during operation of the proposed project are considered to be cumulatively considerable (CEQA Guidelines §15064 (h)(1)).

The 2017 Clean Air Plan contains a total of 85 control measures that the District intends to impose to improve overall air quality in the District. Control measures in the 2017 Clean Air Plan included Rule 12-16 as well as a number of other control measures to control emissions from refineries as well as other stationary sources and transportation control measures. The 2017 Clean Air Plan is expected to result in overall reductions in VOC, NOx, SOx, and PM emissions, providing an air quality benefit (BAAQMD, 2017). The Final EIR for the 2017 Air Plan evaluated the potential hydrology and water quality impacts associated with implementation of the 85 control measures (including Control Measure SS11 Petroleum Refining Facility-Wide Emission Limits, which is proposed Rule 12-16) and concluded that the 2017 Plan could result in the installation of control equipment that would ustilize water in excess of the water demand significance thresholds. Accordingly, stationary source control measures in the 2017 Plan may result in a cumulative considerable contribution to water demand. The impacts on wastewater treatment and water quality associated with the 2017 Plan does not include any specifically identified actions that would result in any cumulatively considerable contributions to water treatment and water quality impacts.

CHAPTER 3.4

HAZARDS AND HAZARDOUS MATERIALS

Introduction
Environmental Setting
Regulatory Setting
Significance Thresholds
Environmental Impacts
Mitigation Measures
Cumulative Impacts

3.4 HAZARDS AND HAZARDOUS MATERIALS

This subchapter of the EIR evaluates the potential hazards and hazardous material impacts associated with implementation of Rule~~s 11-18 and/or~~ 12-16. Rule 12-16 would establish numeric emission limits on specific refinery and associated facilities within the Bay Area. ~~Rule 11-18 would reduce exposure to TAC emissions from a number of stationary sources within the Bay Area, including refineries.~~

~~As discussed in the Initial Study, implementation of Rule 11-18 would reduce risk from facilities that emit toxic air contaminants throughout the Bay Area. Risk reduction measures are expected to be limited to new air pollution control equipment and construction of enclosures. The NOP/IS concluded that wet gas scrubbers were not expected to be used to control TACs; therefore, implementation of Rule 11-18 was not expected to result in a substantial hazard and hazardous material impacts. However, public comments received on the NOP/IS indicated that wet gas scrubbers could be used to control TAC emissions for certain units at refineries. Thus, potential hazards and hazardous material impacts are included in this EIR for proposed Rule 11-18.~~

Implementation of Rule 12-16 would prevent refinery emissions of GHGs and some criteria pollutants from increasing. However, Rule 12-16 could require the installation of additional air pollution control equipment or modifications to refinery operations. In particular, NOx emission reduction measures could result in the increased use of ammonia, which is a hazardous material, in selective catalytic reduction units and Ultracat catalyst filters. The NOP/IS (see Appendix A) determined potential hazards and hazardous material impacts associated with the implementation of the proposed new Rule 12-16 are potentially significant. The, project-specific and cumulative adverse hazards and hazardous material impacts associated with implementation of proposed Rule~~s 11-18 and~~ 12-16 have been evaluated in Chapter 3.4 of this EIR.

3.4.1 ENVIRONMENTAL SETTING

The potential for hazards exist in the production, use, storage and transportation of hazardous materials. Hazardous materials may be found at industrial production and processing facilities. Some facilities produce hazardous materials as their end product, while others use such materials as an input to their production process. Examples of hazardous materials used as consumer products include gasoline, solvents, and coatings/paints. Hazardous materials are stored at facilities that produce such materials and at facilities where hazardous materials are a part of the production process. Specifically, storage refers to the bulk handling of hazardous materials before and after they are transported to the general geographical area of use. Currently, hazardous materials are transported throughout the district in great quantities via all modes of transportation including rail, highway, water, air, and pipeline.

The potential hazards associated with industrial activities are a function of the materials being processed, processing systems, and procedures used to operate and maintain the facility. The hazards that are likely to exist are identified by the physical and chemical properties of the materials being handled and their process conditions, including the following events:

- **Toxic gas clouds:** Toxic gas clouds are releases of volatile chemicals (e.g., anhydrous ammonia, chlorine, and hydrogen sulfide) that could form a cloud and migrate off-site, thus exposing individuals. "Worst-case" conditions tend to arise when very low wind speeds coincide with an accidental release, which can allow the chemicals to accumulate rather than disperse.

- **Torch fires (gas and liquefied gas releases), flash fires (liquefied gas releases), pool fires, and vapor cloud explosions (gas and liquefied gas releases):** The rupture of a storage tank or vessel containing a flammable gaseous material (like propane or gasoline), without immediate ignition, can result in a vapor cloud explosion. The "worst-case" upset would be a release that produces a large aerosol cloud with flammable properties. If the flammable cloud does not ignite after dispersion, the cloud would simply dissipate. If the flammable cloud were to ignite during the release, a flash fire or vapor cloud explosion could occur. If the flammable cloud were to ignite immediately upon release, a torch fire would ensue.

- **Thermal Radiation:** Thermal radiation is the heat generated by a fire and the potential impacts associated with exposure. Exposure to thermal radiation would result in burns, the severity of which would depend on the intensity of the fire, the duration of exposure, and the distance of an individual to the fire.

- **Explosion/Overpressure:** Process vessels containing flammable explosive vapors and potential ignition sources are present at industrial facilities, e.g., refineries and chemical plants. Explosions may occur if the flammable/explosive vapors came into contact with an ignition source. An explosion could cause impacts to individuals and structures in the area due to overpressure.

3.4.1.1 Hazardous Materials Incidents

The Department of Transportation, Office of Pipeline and Hazardous Materials Safety Administration (PHMSA) utilizes a post incident reporting system that collects data on incidents involving accidents. Information on accidental releases of hazardous materials are reported to PHMSA. In 2015, 1,489 hazardous materials incidents that occurred within California were reported to PHMSA. The incidents resulted in 295 non-hospitalized injuries, 94 people hospitalized, 11 fatalities, and approximately $107 million in damages (PHMSA, 2016).

In the last ten years, 42 hazardous materials incidents related to anhydrous or aqueous ammonia that occurred within California have been reported to PHMSA. Six of those incidents occurred in the Bay Area. The Bay area incidents resulted in no injuries (hospitalized or non-hospitalized) and caused about $5,200 in damages (PHMSA, 2016).

The California Hazardous Materials Incident Reporting System (CHMIRS) is a post incident reporting system to collect data on incidents involving the accidental release of hazardous materials. Information on accidental releases of hazardous materials are reported to and maintained by Cal EMA. While information on accidental releases are reported to Cal EMA, Cal EMA no longer conducts statistical evaluations of the releases. PHMSA provides access to retrieve data from the Incident Reports Database, which also includes non-pipeline incidents, e.g., truck and rail events. Incident data and summary statistics, e.g., release date geographical location (state and county) and type of material released, are available online from the Hazmat Incident Database.

Table 3.4-1 provides a summary of the reported hazardous materials incidents in the nine counties within the Bay Area. In 2015, there were a total of 1,272 incidents reported in the nine counties regulated by the BAAQMD (see Table 3.4-1), with the most incidents (292) reported in Alameda County, followed by Contra Costa County (248).

TABLE 3.4-1

Hazardous Materials Incidents 2015 by County

COUNTY	REPORTED INCIDENTS
Alameda	292
Contra Costa	248
Marin	70
Napa	22
San Francisco	90
San Mateo	108
Santa Clara	198
Solano*	134
Sonoma*	110
Total No. of Reported Incidents	1,272

Source: OES, 2016

* Not all of Solano or Sonoma Counties are within the jurisdiction of BAAQMD

The location of the spills varies (see Table 3.4-2). In the nine counties that comprise the Air District, hazardous materials incidents during transportation, at waterways, and at commercial facilities were the most common locations, respectively, for hazardous materials incidents. About 17 percent of the hazardous materials incidents that occurred within California occurred within the nine counties that comprise the Bay Area, with spills in industrial areas the most common (27 percent), followed by waterways (22 percent) and commercial areas (20 percent).

TABLE 3.4-2

Hazardous Materials Incidents 2015

Spillsite	BAAQMD	Statewide	Percent of State Total
Waterways	160	734	22%
Transportation	480	2843	17%
Industrial	81	298	27%
Commercial	266	1364	20%
Residential	162	895	18%
Utilities	26	194	13%
Military	1	61	2%
Other	96	928	10%
Total	**1,272**	**7,317**	**17%**

Source: OES, 2016

3.4.1.2 Potential Hazards Associated with Air Pollution Control Equipment

The BAAQMD has evaluated the hazards associated with previous air plans (2010 Clean Air Plan) and proposed BAAQMD rules. The analyses covered a range of potential air pollution control technologies and equipment. EIRs prepared for the previous rules and air plans have specifically evaluated hazard impacts from add-on pollution control equipment.

Add on pollution control technologies include carbon adsorption, incineration, post-combustion flue-gas treatment, SCR and selective non-catalytic reduction, scrubbers, bag filters and electrostatic precipitators. The use of add-on pollution control equipment may concentrate or utilize hazardous materials. A malfunction or accident when using add-on pollution control equipment could potentially expose people to hazardous materials, explosions, or fires. The transport, use, and storage of ammonia, both aqueous and anhydrous (used in SCR systems), may result in a release in the event of an accident. Previous studies have indicated that the use of aqueous ammonia (instead of anhydrous ammonia) can usually reduce the hazards associated with ammonia use in SCR systems.

3.4.2 REGULATORY SETTING

There are many federal and state rules and regulations for handling hazardous materials, which serve to minimize the potential impacts associated with hazards.

3.4.2.1 Federal Regulations

The U.S. EPA is the primary federal agency charged with protecting human health and with safeguarding the natural environment from pollution into air, water, and land. The U.S. EPA works to develop and enforce regulations that implement environmental laws enacted by Congress. The U.S. EPA is responsible for researching and setting national standards for a variety of environmental programs, and delegates to states and Indian tribes the responsibility for issuing permits and for monitoring and enforcing compliance. Since 1970, Congress has enacted numerous environmental laws that pertain to hazardous materials, for the U.S. EPA to implement as well as to other agencies at the federal, state and local level, as described in the following subsections.

3.4.2.1.1 Hazardous Materials and Waste Regulations

Resource Conservation and Recovery Act: The Resource Conservation and Recovery Act (RCRA) of 1976 authorizes the U.S. EPA to control the generation, transportation, treatment, storage, and disposal of hazardous waste. RCRA considers materials and waste to be hazardous based on four characteristics: ignitability, corrosivity, reactivity, and toxicity. Under RCRA regulations, hazardous wastes must be tracked from the time of generation to the point of disposal. In 1984, RCRA was amended with addition of the Hazardous and Solid Waste Amendments, which authorized increased enforcement by the U.S. EPA, stricter hazardous waste standards, and a comprehensive underground storage tank program. Likewise, the Hazardous and Solid Waste Amendments focused on waste reduction and corrective action for hazardous releases. The use of certain techniques for the disposal of some hazardous wastes was specifically prohibited by the Hazardous and Solid Waste Amendments. Individual states may implement their own hazardous waste programs under RCRA, with approval by the U.S. EPA. California has been delegated authority to operate its own hazardous waste management program.

Comprehensive Environmental Response, Compensation and Liability Act: The Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA), which is often commonly referred to as Superfund, is a federal statute that was enacted in 1980 to address abandoned sites containing hazardous waste and/or contamination. CERCLA was amended in 1986 by the Superfund Amendments and Reauthorization Act, and by the Small Business Liability Relief and Brownfields Revitalization Act of 2002.

CERCLA contains prohibitions and requirements concerning closed and abandoned hazardous waste sites; establishes liability of persons responsible for releases of hazardous waste at these sites; and establishes a trust fund to provide for cleanup when no responsible party can be identified. The trust fund is funded largely by a tax on the chemical and petroleum industries. CERCLA also provides federal jurisdiction to respond directly to releases or impending releases of hazardous substances that may endanger public health or the environment.

CERCLA also enabled the revision of the National Contingency Plan (NCP) which provided the guidelines and procedures needed to respond to releases and threatened releases of hazardous substances, pollutants, or contaminants. The NCP also established the National Priorities List, which identifies hazardous waste sites eligible for long-term remedial action financed under the federal Superfund program.

Prevention of Accidental Releases and Risk Management Programs: Requirements pertaining to the prevention of accidental releases are promulgated in §112 (r) of the CAA Amendments of 1990 [42 U.S.C. §7401 et. seq.]. The objective of these requirements was to prevent the accidental release and to minimize the consequences of any such release of a hazardous substances. Under these provisions, facilities that produce, process, handle or store hazardous substances have a duty to: 1) identify hazards which may result from releases using hazard assessment techniques; 2) design and maintain a safe facility and take steps necessary to prevent releases; and, 3) minimize the consequence of accidental releases that occur.

In accordance with the requirements in §112 (r), U.S. EPA adopted implementing guidelines in 40 CFR Part 68. Under this part, stationary sources with more than a threshold quantity of a regulated substance shall be evaluated to determine the potential for and impacts of accidental releases from any processes subject to the federal risk management requirements. Under certain conditions, the owner or operator of a stationary source may be required to develop and submit a Risk Management Plan (RMP). RMPs consist of three main elements: a hazard assessment that includes off-site consequences analyses and a five-year accident history, a prevention program, and an emergency response program. At the local level, RMPs are implemented by the local fire departments.

3.4.2.1.2 Emergency Planning and Community Right-to-Know Act

The Emergency Planning and Community Right-to-Know Act (EPCRA) is a federal law adopted by Congress in 1986 that is designed to help communities plan for emergencies involving hazardous substances. EPCRA establishes requirements for federal, state and local governments, Indian tribes, and industry regarding emergency planning and "Community Right-to-Know" reporting on hazardous and toxic chemicals. The Community Right-to-Know provisions help increase the public's knowledge and access to information on chemicals at individual facilities, their uses, and releases into the environment. States and communities, working with facilities, can use the information to improve chemical safety and protect public health and the environment. There are four major provisions of EPCRA:

1. Emergency Planning (§§301 – 303) requires local governments to prepare chemical emergency response plans, and to review plans at least annually. These sections also require state governments to oversee and coordinate local planning efforts. Facilities that maintain Extremely Hazardous Substances (EHS) onsite (see 40 CFR Part 355 for the list of EHS chemicals) in quantities greater than corresponding “Threshold Planning Quantities” must cooperate in the preparation of the emergency plan.

2. Emergency Release Notification (§304) requires facilities to immediately report accidental releases of EHS chemicals and hazardous substances in quantities greater than corresponding Reportable Quantities (RQs) as defined under the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA) to state and local officials. Information about accidental chemical releases must be made available to the public.

3. Hazardous Chemical Storage Reporting (§§311 – 312) requires facilities that manufacture, process, or store designated hazardous chemicals to make Safety Data Sheets (SDSs, formerly referred to as material safety data sheets or MSDSs) describing the properties and

health effects of these chemicals available to state and local officials and local fire departments. These sections also require facilities to report to state and local officials and local fire departments, inventories of all onsite chemicals for which SDSs exist. Lastly, information about chemical inventories at facilities and SDSs must be available to the public.

4. Toxic Chemical Release Inventory (§313) requires facilities to annually complete and submit a Toxic Chemical Release Inventory Form for each Toxic Release Inventory (TRI) chemical that are manufactured or otherwise used above the applicable threshold quantities.

Implementation of EPCRA has been delegated to the State of California. The California Emergency Management Agency requires facilities to develop a Hazardous Materials Business Plan if they handle hazardous materials in quantities equal to or greater than 55 gallons, 500 pounds, or 200 cubic feet of gas or extremely hazardous substances above the threshold planning quantity. The Hazardous Materials Business Plan is provided to state and local emergency response agencies and includes inventories of hazardous materials, an emergency plan, and implements a training program for employees.

3.4.2.1.3 Hazardous Materials Transportation Act

The Hazardous Material Transportation Act (HMTA), adopted in 1975 (see 49 U.S.C. §§5101 – 5127), gave the Secretary of Transportation the regulatory and enforcement authority to provide adequate protection against the risks to life and property inherent in the transportation of hazardous materials in commerce. The U.S. DOT (see 49 CFR Parts 171-180) oversees the movement of hazardous materials at the federal level. The HMTA requires that carriers report accidental releases of hazardous materials to U.S. DOT at the earliest practical moment. Other incidents that must be reported include deaths, injuries requiring hospitalization, and property damage exceeding $50,000. The hazardous material regulations also contain emergency response provisions which include incident reporting requirements. Reports of major incidents go to the National Response Center, which in turn is linked with CHEMTREC, a public service hotline established by the chemical manufacturing industry for emergency responders to obtain information and assistance for emergency incidents involving chemicals and hazardous materials.

Hazardous materials regulations are implemented by the Research and Special Programs Administration (RSPA) branch of the U.S. DOT. The regulations cover the definition and classification of hazardous materials, communication of hazards to workers and the public, packaging and labeling requirements, operational rules for shippers, and training. These regulations apply to interstate, intrastate, and foreign commerce by air, rail, ships, and motor vehicles, and also cover hazardous waste shipments. The Federal Aviation Administration Office of Hazardous Materials Safety is responsible for overseeing the safe handling of hazardous materials aboard aircraft. The Federal Railroad Administration oversees the transportation of hazardous materials by rail. The U.S. Coast Guard regulates the bulk transport of hazardous materials by sea. The Federal Highway Administration (FHWA) is responsible for highway routing of hazardous materials and issuing highway safety permits.

3.4.2.1.4 Toxic Substances Control Act

The Toxic Substances Control Act (TSCA) was enacted by Congress in 1976 (see 15 U.S.C. §2601 et seq.) and gave the U.S. EPA the authority to protect the public from unreasonable risk of injury to health or the environment by regulating the manufacture, sale, and use of chemicals currently produced or imported into the United States. The TSCA, however, does not address wastes produced as byproducts of manufacturing. The types of chemicals regulated by the act fall into two categories: existing and new. New chemicals are defined as "any chemical substance which is not included in the chemical substance list compiled and published under [TSCA] section 8(b)." This list included all of chemical substances manufactured or imported into the U.S. prior to December 1979. Existing chemicals include any chemical currently listed under section 8 (b). The distinction between existing and new chemicals is necessary as the act regulates each category of chemicals in different ways. The U.S. EPA repeatedly screens both new and existing chemicals and can require reporting or testing of those that may pose an environmental or human-health hazard. The U.S. EPA can ban the manufacture and import of those chemicals that pose an unreasonable risk.

3.4.2.1.5 Hazardous Material Worker and Public Safety Requirements

Occupational Safety and Health Administration Regulations: The federal Occupational Safety and Health Administration (OSHA) is an agency of the United States Department of Labor that was created by Congress under the Occupational Safety and Health Act in 1970. OSHA is the agency responsible for assuring worker safety in the handling and use of chemicals in the workplace. Under the authority of the Occupational Safety and Health Act of 1970, OSHA has adopted numerous regulations pertaining to worker safety (see 29 CFR Part 1910). These regulations set standards for safe workplaces and work practices, including the reporting of accidents and occupational injuries. Some OSHA regulations contain standards relating to hazardous materials handling to protect workers who handle toxic, flammable, reactive, or explosive materials, including workplace conditions, employee protection requirements, first aid, and fire protection, as well as material handling and storage. For example, facilities which use, store, manufacture, handle, process, or move hazardous materials are required to conduct employee safety training, have available and know how to use safety equipment, prepare illness prevention programs, provide hazardous substance exposure warnings, prepare emergency response plans, and prepare a fire prevention plan.

Procedures and standards for safe handling, storage, operation, remediation, and emergency response activities involving hazardous materials and waste are promulgated in 29 CFR Part 1910, Subpart H. Some key subsections in 29 CFR Part 1910, Subpart H are §1910.106 -Flammable Liquids and §1910.120 - Hazardous Waste Operations and Emergency Response. In particular, the Hazardous Waste Operations and Emergency Response regulations contain requirements for worker training programs, medical surveillance for workers engaging in the handling of hazardous materials or wastes, and waste site emergency and remediation planning, for those who are engaged in specific clean-up, corrective action, hazardous material handling, and emergency response activities (see 29 CFR Part 1910 Subpart H, §1910.120 (a)(1)(i-v) and §1926.65 (a)(1)(i-v)).

Process Safety Management: As part of the numerous regulations pertaining to worker safety adopted by OSHA, specific requirements that pertain to Process Safety Management (PSM) of Highly Hazardous Chemicals were adopted in 29 CFR Part 1910 Subpart H, §1910.119 and 8 CCR §5189 to protect workers at facilities that have toxic, flammable, reactive or explosive materials. PSM program elements are aimed at preventing or minimizing the consequences of catastrophic releases of chemicals and include process hazard analyses, formal training programs for employees and contractors, investigation of equipment mechanical integrity, and an emergency response plan. Specifically, the PSM program requires facilities that use, store, manufacture, handle, process, or move hazardous materials to conduct employee safety training; have an inventory of safety equipment relevant to potential hazards; have knowledge on use of the safety equipment; prepare an illness prevention program; provide hazardous substance exposure warnings; prepare an emergency response plan; and prepare a fire prevention plan.

Emergency Action Plan: An Emergency Action Plan (EAP) is a written document required by OSHA standards promulgated in 29 CFR Part 1910, Subpart E, §1910.38 (a) to facilitate and organize a safe employer and employee response during workplace emergencies. An EAP is required by all that are required to have fire extinguishers. At a minimum, an EAP must include the following: 1) a means of reporting fires and other emergencies; 2) evacuation procedures and emergency escape route assignments; 3) procedures to be followed by employees who remain to operate critical plant operations before they evacuate; 4) procedures to account for all employees after an emergency evacuation has been completed; 5) rescue and medical duties for those employees who are to perform them; and, 6) names or job titles of persons who can be contacted for further information or explanation of duties under the plan.

National Fire Regulations: The National Fire Codes (NFC), Title 45, published by the National Fire Protection Association (NFPA) contains standards for laboratories using chemicals, which are not requirements, but are generally employed by organizations in order to protect workers. These standards provide basic protection of life and property in laboratory work areas through prevention and control of fires and explosions, and also serve to protect personnel from exposure to non-fire health hazards.

In addition to the NFC, the NFPA adopted a hazard rating system which is promulgated in NFPA 704 - Standard System for the Identification of the Hazards of Materials for Emergency Response. NFPA 704 is a "standard (that) provides a readily recognized, easily understood system for identifying specific hazards and their severity using spatial, visual, and numerical methods to describe in simple terms the relative hazards of a material. It addresses the health, flammability, instability, and related hazards that may be presented as short-term, acute exposures that are most likely to occur as a result of fire, spill, or similar emergency." In addition, the hazard ratings per NFPA 704 are used by emergency personnel to quickly and easily identify the risks posed by nearby hazardous materials in order to help determine what, if any, specialty equipment should be used, procedures followed, or precautions taken during the first moments of an emergency response. The scale is divided into four color-coded categories, with blue indicating level of health hazard, red indicating the flammability hazard, yellow indicating the chemical reactivity, and white containing special codes for unique hazards such as corrosivity and radioactivity. Each hazard category is rated on a scale from 0 (no hazard; normal substance) to 4 (extreme risk). Table 3.4-3 summarizes what the codes mean for each hazards category.

TABLE 3.4-3

NFPA 704 Hazards Rating Code

Hazard Rating Code	Health (Blue)	Flammability (Red)	Reactivity (Yellow)	Special (White)
4 = Extreme	Very short exposure could cause death or major residual injury (extreme hazard).	Will rapidly or completely vaporize at normal atmospheric pressure and temperature, or is readily dispersed in air and will burn readily. Flash point below 73°F.	Readily capable of detonation or explosive decomposition at normal temperatures and pressures.	W = Reacts with water in an unusual or dangerous manner.
3 = High	Short exposure could cause serious temporary or moderate residual injury.	Liquids and solids that can be ignited under almost all ambient temperature conditions. Flash point between 73°F and 100°F.	Capable of detonation or explosive decomposition but requires a strong initiating source, must be heated under confinement before initiation, reacts explosively with water, or will detonate if severely shocked.	**OXY** = Oxidizer
2 = Moderate	Intense or continued but not chronic exposure could cause temporary incapacitation or possible residual injury.	Must be moderately heated or exposed to relatively high ambient temperature before ignition can occur. Flash point between 100°F and 200°F.	Undergoes violent chemical change at elevated temperatures and pressures, reacts violently with water, or may form explosive mixtures with water.	**SA** = Simple asphyxiant gas (includes nitrogen, helium, neon, argon, krypton, and xenon).
1 = Slight	Exposure would cause irritation with only minor residual injury.	Must be heated before ignition can occur. Flash point over 200°F.	Normally stable, but can become unstable at elevated temperatures and pressures.	Not applicable
0 = Insignificant	Poses no health hazard, no precautions necessary.	Will not burn.	Normally stable, even under fire exposure conditions, and is not reactive with water.	Not applicable

In addition to the information in Table 3.4-3, a number of other physical or chemical properties may cause a substance to be a fire hazard. With respect to determining whether any substance is classified as a fire hazard, SDS lists the NFPA 704 flammability hazard ratings (e.g., NFPA 704). Although substances can have the same NFPA 704 Flammability Ratings Code, other factors can make each substance's fire hazard very different from each other. For this reason, additional chemical characteristics, such as auto-ignition temperature, boiling point, evaporation rate, flash point, lower explosive limit (LEL), upper explosive limit (UEL), and vapor pressure, are also considered when determining whether a substance is fire hazard. The following is a brief description of each of these chemical characteristics.

> Auto-ignition Temperature: The auto-ignition temperature of a substance is the lowest temperature at which it will spontaneously ignite in a normal atmosphere without an external source of ignition, such as a flame or spark.
>
> Boiling Point: The boiling point of a substance is the temperature at which the vapor pressure of the liquid equals the environmental pressure surrounding the liquid. Boiling is a process in which molecules anywhere in the liquid escape, resulting in the formation of vapor bubbles within the liquid.
>
> Evaporation Rate: Evaporation rate is the rate at which a material will vaporize (evaporate, change from liquid to a vapor) compared to the rate of vaporization of a specific known material. This quantity is a represented as a unit less ratio. For example, a substance with a high evaporation rate will readily form a vapor which can be inhaled or explode, and thus have a higher hazard risk. Evaporation rates generally have an inverse relationship to boiling points (i.e., the higher the boiling point, the lower the rate of evaporation).
>
> Flash Point: Flash point is the lowest temperature at which a volatile liquid can vaporize to form an ignitable mixture in air. Measuring a liquid's flash point requires an ignition source. At the flash point, the vapor may cease to burn when the source of ignition is removed. There are different methods that can be used to determine the flashpoint of a solvent but the most frequently used method is the Tagliabue Closed Cup standard (ASTM D56), also known as the TCC. The flashpoint is determined by a TCC laboratory device which is used to determine the flash point of mobile petroleum liquids with flash point temperatures below 175 degrees Fahrenheit (79.4 degrees Centigrade).
>
> Flash point is a particularly important measure of the fire hazard of a substance. For example, the Consumer Products Safety Commission (CPSC) promulgated Labeling and Banning Requirements for Chemicals and Other Hazardous Substances in 15 U.S.C. §1261 and 16 CFR Part 1500. Per the CPSC, the flammability of a product is defined in 16 CFR Part 1500.3 (c)(6) and is based on flash point. For example, a liquid needs to be labeled as: 1) “Extremely Flammable” if the flash point is below 20 degrees Fahrenheit; 2) “Flammable” if the flash point is above 20 degrees Fahrenheit but less than 100 degrees Fahrenheit; or, 3) “Combustible” if the flash point is above 100 degrees Fahrenheit up to and including 150 degrees Fahrenheit.
>
> Lower Explosive Limit (LEL): The lower explosive limit of a gas or a vapor is the limiting concentration (in air) that is needed for the gas to ignite and explode or the lowest concentration (percentage) of a gas or a vapor in air capable of producing a flash of fire in presence of an ignition source (e.g., arc, flame, or heat). If the concentration of a substance in air is below the LEL, there is not enough fuel to continue an explosion. In other words, concentrations lower than the LEL are "too lean" to burn. For example, methane gas has

a LEL of 4.4 percent (at 138 degrees Centigrade) by volume, meaning 4.4 percent of the total volume of the air consists of methane. At 20 degrees Centigrade, the LEL for methane is 5.1 percent by volume. If the atmosphere has less that 5.1 percent methane, an explosion cannot occur even if a source of ignition is present. When the concentration of methane reaches 5.1 percent, an explosion can occur if there is an ignition source.

Upper Explosive Limit (UEL): The upper explosive limit of a gas or a vapor is the highest concentration (percentage) of a gas or a vapor in air capable of producing a flash of fire in presence of an ignition source (e.g., arc, flame, or heat). Concentrations of a substance in air above the UEL are "too rich" to burn.

Vapor Pressure: Vapor pressure is an indicator of a chemical's tendency to evaporate into gaseous form.

Health Hazards Guidance: In addition to fire impacts, health hazards can also be generated due to exposure of chemicals present in both conventional as well as reformulated products. Using available toxicological information to evaluate potential human health impacts associated with conventional solvents and potential replacement solvents, the toxicity of the conventional solvents can be compared to solvents expected to be used in reformulated products. As a measure of a chemical's potential health hazards, the following values need to be considered: the Threshold Limit Values established by the American Conference of Governmental Industrial Hygiene, OSHA's Permissible Exposure Limits, the Immediately Dangerous to Life and Health levels recommended by the National Institute for Occupational Safety and Health (NIOSH), and health hazards developed by the National Safety Council. The following is a brief description of each of these values.

Threshold Limit Values (TLVs): The TLV of a chemical substance is a level to which it is believed a worker can be exposed day after day for a working lifetime without adverse health effects. The TLV is an estimate based on the known toxicity in humans or animals of a given chemical substance, and the reliability and accuracy of the latest sampling and analytical methods. The TLV for chemical substances is defined as a concentration in air, typically for inhalation or skin exposure. Its units are in parts per million (ppm) for gases and in milligrams per cubic meter (mg/m^3) for particulates. The TLV is a recommended guideline by ACGIH.

Permissible Exposure Limits (PEL): The PEL is a legal limit, usually expressed in ppm, established by OSHA to protect workers against the health effects of exposure to hazardous substances. PELs are regulatory limits on the amount or concentration of a substance in the air. A PEL is usually given as a time-weighted average (TWA), although some are short-term exposure limits (STEL) or ceiling limits. A TWA is the average exposure over a specified period of time, usually eight hours. This means that, for limited periods, a worker may be exposed to concentrations higher than the PEL, so long as the average concentration over eight hours remains lower. A short-term exposure limit is one that addresses the average exposure over a 15 to 30 minute period of maximum exposure during a single work shift. A ceiling limit is one that may not be exceeded for any period of time, and is applied to irritants and other materials that have immediate effects. The OSHA PELs are published in 29 CFR 1910.1000, Table Z1.

Immediately Dangerous to Life and Health (IDLH): IDLH is an acronym defined by NIOSH as exposure to airborne contaminants that is "likely to cause death or immediate or delayed permanent adverse health effects or prevent escape from such an environment." IDLH values are often used to guide the selection of breathing apparatus that are made available to workers or firefighters in specific situations.

3.4.2.1.6 Oil and Pipeline Regulations and Oversight

Oil Pollution Act: The Oil Pollution Act was signed into law in 1990 to give the federal government authority to better respond to oil spills. The Oil Pollution Act improved the federal government's ability to prevent and respond to oil spills, including provision of money and resources. The Oil Pollution Act establishes polluter liability, gives states enforcement rights in navigable waters of the state, mandates the development of spill control and response plans for all vessels and facilities, increases fines and enforcement mechanisms, and establishes a federal trust fund for financing clean-up.

The Oil Pollution Act also establishes the National Oil Spill Liability Trust Fund to provide financing for cases in which the responsible party is either not readily identifiable, or refuses to pay the cleanup/damage costs. In addition, the Oil Pollution Act expands provisions of the National Oil and Hazardous Substances Pollution Contingency Plan, more commonly called the National Contingency Plan, requiring the federal government to direct all public and private oil spill response efforts. It also requires area committees, composed of federal, state, and local government officials, to develop detailed, location-specific area contingency plans. In addition, the Oil Pollution Act directs owners and operators of vessels, and certain facilities that pose a serious threat to the environment, to prepare their own specific facility response plans. The Oil Pollution Act increases penalties for regulatory non-compliance by responsible parties; gives the federal government broad enforcement authority; and provides individual states the authority to establish their own laws governing oil spills, prevention measures, and response methods.

Oil Pollution Prevention Regulation: In 1973, the USEPA issued the Oil Pollution Prevention regulation (see 40 CFR 112)**,** to address the oil spill prevention provisions contained in the Clean Water Act of 1972. The Spill Prevention, Control, and Countermeasure (SPCC) Rule is part of the Oil Pollution Prevention regulations (see 40 CFR Part 112, Subparts A - C). Specifically, the SPCC rule includes requirements for oil spill prevention, preparedness, and response to prevent oil discharges to navigable waters and adjoining shorelines. The rule requires specific facilities to prepare, amend, and implement SPCC Plans. SPCC Plans require applicable facilities to take steps to prevent oil spills including: 1) using suitable storage containers/tanks; 2) providing overfill prevention (e.g., high-level alarms); 3) providing secondary containment for bulk storage tanks; 4) providing secondary containment to catch oil spills during transfer activities; and, 5) periodically inspecting and testing pipes and containers.

U.S. Department of Transportation, Office of Pipeline Safety: The Office of Pipeline Safety, within the U.S. DOT, Pipeline and Hazards Material Safety Administration, has jurisdictional responsibility for developing regulations and standards to ensure the safe and secure movement of hazardous liquid and gas pipelines under its jurisdiction in the United States. The Office of Pipeline Safety has the following key responsibilities:

- Support the operation of, and coordinate with the United States Coast Guard on the National Response Center and serve as a liaison with the Department of Homeland Security and the Federal Emergency Management Agency on matters involving pipeline safety;

- Develop and maintain partnerships with other federal, state, and local agencies, public interest groups, tribal governments, and the regulated industry and other underground utilities to address threats to pipeline integrity, service, and reliability and to share responsibility for the safety of communities;

- Administer pipeline safety regulatory programs and develops regulatory policy involving pipeline safety;

- Oversee pipeline operator implementation of risk management and risk-based programs and administer a national pipeline inspection and enforcement program;

- Provide technical and resource assistance for state pipeline safety programs to ensure oversight of intrastate pipeline systems and educational programs at the local level; and,

- Support the development and conduct of pipeline safety training programs for federal and state regulatory and compliance staff and the pipeline industry.

49 CFR Parts 178 – 185 relates to the role of transportation, including pipelines, in the United States. 49 CFR Parts 186-199 establishes minimum pipeline safety standards. The Office of the State Fire Marshal works in partnership with the Federal Pipeline and Hazardous Materials Safety Administration to assure pipeline operators are meeting requirements for safe, reliable, and environmentally sound operation of their facilities for intrastate pipelines within California.

Chemical Facility Anti-Terrorism Standards: The Federal Department of Homeland Security established the chemical facility anti-terrorism standards in 2007 (see 6 CFR Part 27). These regulations established risk-based performance standards for the security of chemical facilities and require covered chemical facilities to prepare Security Vulnerability Assessments, which identify facility security vulnerabilities, and to develop and implement security plans.

3.4.2.2 State Regulations

California Hazardous Waste Control Law: The California Hazardous Waste Control Law is administered by the California Environmental Protection Agency (CalEPA) to regulate hazardous wastes within the State of California. While the California Hazardous Waste Control Law is generally more stringent than RCRA, both the state and federal laws apply in California. The California Department of Toxic Substances Control (DTSC) is the primary agency in charge of enforcing both the federal and state hazardous materials laws in California. The DTSC regulates hazardous waste, oversees the cleanup of existing contamination, and pursues methods to reduce hazardous waste produced in California. The DTSC regulates hazardous waste in California under the authority of RCRA, the California Hazardous Waste Control Law, and the California Health and Safety Code. Under the direction of the CalEPA, the DTSC maintains the Cortese List and Envirostor databases of hazardous materials and waste sites as specified under Government Code §65962.5.

The Hazardous Waste Control Law (22 CCR Chapter 11, Appendix X) also lists 791 chemicals and approximately 300 common materials which may be hazardous; establishes criteria for identifying, packaging, and labeling hazardous wastes; prescribes management controls; establishes permit requirements for treatment, storage, disposal, and transportation; and identifies some wastes that cannot be disposed of in landfills.

California Occupational Safety and Health Administration: The California Occupational Safety and Health Administration (CalOSHA) is the primary agency responsible for worker safety in the handling and use of chemicals in the workplace. CalOSHA requires the employer to monitor worker exposure to listed hazardous substances and notify workers of exposure (8 CCR Sections 337-340). The regulations specify requirements for employee training, availability of safety equipment, accident-prevention programs, and hazardous substance exposure warnings. CalOSHA standards are generally more stringent than federal regulations.

Hazardous Materials Release Notification: Many state statutes require emergency notification of a hazardous chemical release, including:

- California Health and Safety Code §25270.7, §25270.8, and §25507;
- California Vehicle Code §23112.5;
- California Public Utilities Code §7673 (General Orders #22-B, 161);
- California Government Code §51018 and §8670.25.5(a);
- California Water Code §13271 and §13272; and,
- California Labor Code §6409.1(b)10.

California Accident Release Prevention (CalARP) Program: The California Accident Release Prevention Program (19 CCR Division 2, Chapter 4.5) requires the preparation of RMPs. CalARP requires stationary sources with more than a threshold quantity of a regulated substance to be evaluated to determine the potential for and impacts of accidental releases from any processes onsite (not transport) subject to state risk management requirements. RMPs are documents prepared by the owner or operator of a stationary source containing detailed information including: (1) regulated substances held onsite at the stationary source; (2) offsite consequences of an accidental release of a regulated substance; (3) the accident history at the stationary source; (4) the emergency response program for the stationary source; (5) coordination with local emergency responders; (6) hazard review or process hazard analysis; (7) operating procedures at the stationary source; (8) training of the stationary source's personnel; (9) maintenance and mechanical integrity of the stationary source's physical plant; and (10) incident investigation. The CalARP program is implemented at the local government level by Certified Unified Program Agencies (CUPAs) also known as Administering Agencies (AAs). Typically, local fire departments are the administering agencies of the CalARP program because they frequently are the first responders in the event of a release. California is proposing modifications to the CalARP Program along with the state's PSM program in response to an accident at the Chevron Richmond Refinery. The proposed regulations were released for public comment on July 15, 2016 and the public comment period closes on September 15, 2016. After the close of the comment period a modified version of the proposed regulations was released in February 2017 and the public comment period for comments on the modifications closed on March 3, 2017.

Hazardous Materials Disclosure Program: The Unified Hazardous Waste and Hazardous Materials Management Regulatory Program (Unified Program) as promulgated by CalEPA in CCR, Title 27, Chapter 6.11 requires the administrative consolidation of six hazardous materials and waste programs (program elements) under one agency, a CUPA. The Unified Program administered by the State of California consolidates, coordinates, and makes consistent the administrative requirements, permits, inspections, and enforcement activities for the state's environmental and emergency management programs, which include Hazardous Waste Generator and Onsite Hazardous Waste Treatment Programs ("Tiered Permitting"); Above ground SPCC Program; Hazardous Materials Release Response Plans and Inventories (business plans); the CalARP Program; the UST Program; and the Uniform Fire Code Plans and Inventory Requirements. The Unified Program is implemented at the local government level by CUPAs.

Hazardous Materials Management Act: The State of California (California Health and Safety Code Division 20, Chapter 6.95) requires any business that handles more than a specified amount of hazardous or extremely hazardous materials, termed a "reportable quantity," to submit a Hazardous Materials Business Plan to its Certified Unified Program Agency. Business plans must include an inventory of the types, quantities, and locations of hazardous materials at the facility. Businesses are required to update their business plans at least once every three years and the chemical portion of their plans every year. Also, business plans must include emergency response plans and procedures to be used in the event of a significant or threatened significant release of a hazardous material. These plans need to identify the procedures to follow for immediate notification to all appropriate agencies and personnel of a release, identification of local emergency medical assistance appropriate for potential accident scenarios, contact information for all company emergency coordinators, a listing and location of emergency equipment at the business, an evacuation plan, and a training program for business personnel. The requirements for hazardous materials business plans are specified in the California Health and Safety Code and 19 CCR.

Hazardous Materials Transportation in California: California regulates the transportation of hazardous waste originating or passing through the State in Title 13, CCR. The California Highway Patrol (CHP) and Caltrans have primary responsibility for enforcing federal and state regulations and responding to hazardous materials transportation emergencies. The CHP enforces materials and hazardous waste labeling and packing regulations that prevent leakage and spills of material in transit and provide detailed information to cleanup crews in the event of an incident. Vehicle and equipment inspection, shipment preparation, container identification, and shipping documentation are all part of the responsibility of the CHP. Caltrans has emergency chemical spill identification teams at locations throughout the State.

California Fire Code: While NFC Standard 45 and NFPA 704 are regarded as nationally recognized standards, the California Fire Code (24 CCR) also contains state standards for the use and storage of hazardous materials and special standards for buildings where hazardous materials are found. Some of these regulations consist of amendments to NFC Standard 45. State Fire Code regulations require emergency pre-fire plans to include training programs in first aid, the use of fire equipment, and methods of evacuation.

3.4.2.3 Local Regulations

Most counties in California have prepared Hazardous Waste Management Plans (HWMPs) that outlines how hazardous waste generated in the county is managed. The HWMP identifies the types and amounts of wastes generated; establishes programs for managing these wastes; identifies an application review process for the siting of specified hazardous waste facilities; identifies mechanisms for reducing the amount of waste generated; and identifies goals, policies, and actions for achieving effective hazardous waste management

Contra Costa County has adopted an industrial safety ordinance that addresses the human factors that lead to accidents. The ordinance requires stationary sources to develop a written human factors program that considers human factors as part of process hazards analyses, incident investigations, training, operating procedures, among others.

3.4.3 SIGNIFICANCE THRESHOLDS

The impacts associated with hazards will be considered significant if any of the following occur:

- Non-compliance with any applicable design code or regulation.
- Non-conformance to National Fire Protection Association standards.
- Non-conformance to regulations or generally accepted industry practices related to operating policy and procedures concerning the design, construction, security, leak detection, spill containment or fire protection.
- Exposure to hazardous chemicals in concentrations equal to or greater than the Emergency Response Planning Guideline (ERPG) 2 levels.

3.4.4 ENVIRONMENTAL IMPACTS

~~Proposed Rule 11-18: The proposed rule is designed to reduce health risk associated with emissions of TACs from existing stationary sources in the Bay Area. The proposed rule is not expected to require substantial new development. Any new air pollution control equipment or enclosures would be expected to occur within existing commercial or industrial facilities. Facility modifications associated with the proposed rule are largely expected to include limiting throughput or hours of operations; increased use of diesel particulate filters; additional enclosures and bag houses, and thermal oxidizers or carbon adsorption systems. The hazards associated with the use of these types of air pollution control equipment and systems are minimal. Table 3.4-1 summarizes the expected air pollution control equipment and the impacts of those with potential hazard impacts are discussed further in the subsections below.~~

~~Proposed Rule 12-16:~~ For any refineries that are shown to exceed the refinery-wide emissions limits in Rule 12-16, it is expected that refinery operators would install new or modify their existing air pollution control equipment in order to reduce the applicable emissions to comply with Rule 12-16 requirements. Because refineries handle a number of hazardous materials, potential hazards and hazardous materials impacts already exist; are generally common to most oil processing facilities worldwide; and are a function of the materials being processed, processing systems, procedures used for operating and maintaining the facility, and hazard detection, and mitigation systems. The major types of public safety risks at a refinery consist of risks from accidental releases of regulated substances and from major fires and explosions.

Installation of new or modifications to existing air pollution control technologies may generate new hazards at the affected refineries from the use, storage and transport of potentially hazardous materials during operation-related activities. Some of the key effects of implementing Rule 12-16 and the determination of which types of air pollution control equipment involve hazards and hazardous materials focus on: 1) the anticipated increase of potentially hazardous substances used to operate the new air pollution control equipment and the anticipated replacement and/or supplement of substances used to modify or upgrade existing air pollution control systems; and, 2) the increased capture of hazardous substances as part of the overall emission reduction effort. Some control technologies are inherently dangerous or may use hazardous materials, which could contribute to significant adverse hazard or hazardous materials impacts.

Table 3.4-4 shows air pollution control technologies that would provide the best opportunities for obtaining further reductions in criteria pollutant ~~SO_2, PM2.5, and TAC~~ emissions. Table 3.4-4 also identifies the types of hazards or hazardous materials impacts that may be generated by the control technologies under evaluation. Those air pollution control technologies shown in Table 3.4-4 where no hazards or hazardous materials impacts were identified will not be evaluated further. Air pollution control technologies that have the potential to generate hazard or hazardous materials impacts are analyzed further in the subsections below.

TABLE 3.4-4

Potential Hazards Impacts from Installing Air Pollution

Control Equipment under Rule~~s 11-18 or~~ 12-16.

Applicable Rule	Potential Control Technology	Hazard Impacts	Analyzed Further?	Significant?
~~11-18 &~~12-16	Baghouse with HEPA Filters	Potential for fire explosion	Yes	No[1]
~~11-18~~	~~Carbon Adsorption~~	~~None Identified~~	~~No~~	~~No~~
12-16	Compressor	None identified	No	No
12-16	Cyclone	None identified	No	No
~~11-18 &~~ 12-16	Diesel Oxidation Catalyst	None identified	No	No
~~11-18 &~~ 12-16	Diesel Particulate Filter	None identified	No	No
12-16	Electrostatic Precipitator (Wet and Dry)	Potential for explosion	Yes	No[1]
12-16	Fuel Gas Treatment (Additive to Existing Amine System)	Potential hazards associated with increased use of amines	Yes	No
12-16	Fuel Gas Treatment (Merox)	Potential hazards associated with increased use of Merox	Yes	No
12-16	LoTOx™	Potential hazards associated with increased use of caustic or lime.	No	No
~~11-18 &~~ 12-16	Replace old Diesel ICEs with New Diesel ICEs	None identified	No	No
12-16	Selective Catalytic Reduction	Potential hazards associated with increased use of ammonia	Yes	No
12-16	Selective Oxidation Catalyst	Potential hazards associated with catalyst	No	No
~~11-18~~	~~Steam Ejector Technology~~	~~None identified~~	~~No~~	~~No~~
12-16	SOx Reducing Additive	None identified	No	No
~~11-18~~	~~Thermal Oxidizer~~	~~None identified~~	~~No~~	~~No~~
12-16	Ultracat	Potential hazards associated with increased use of ammonia	Yes	No
~~11-18 &~~ 12-16	Wet Gas Scrubber	Potential hazards associated with increased use of ammonia	Yes	No

[1] Implementing mitigation measures in Section 3.4.5 reduces impacts to less than significant.

3.4.4.1 Baghouse~~ – Rules 11-18 and 12-16~~

Dusts have a very large surface area compared to their mass. Since burning can only occur at the surface of a solid or liquid, where it can react with oxygen, this causes dusts to be much more flammable than bulk materials. Explosions are another operating hazard. For an explosion to occur, the concentration of dust in the baghouse housing or duct must be between the lower and upper explosive concentrations and a spark must be present. In mechanical cleaning (shaker) collectors, the flow is stopped in the filter compartment and the filter elements are agitated all at the same time. A potential for an explosion occurs since the concentration will likely pass through the explosive limits during this action.

Although the type of facilities where these accidents occurred were not identified, at least 281 combustible dust fires and explosions from baghouses occurred in general industries between 1980 and 2005 in the United States, which caused at least 119 fatalities and 718 injuries (Dalsanto, 2011). However, based on the chemical and physical characteristics of the dusts involved, e.g., organic, sulfur, coke, etc., it is assumed that at least some of these accidents occurred at industrial facilities. Therefore, in light of the fact that there is a potential for explosion or fire hazards, to be conservative it is concluded here that baghouses may cause or contribute to significant adverse hazard and hazardous materials impacts for ~~both Rule 11-18 and~~ Rule 12-16. Therefore, mitigation measures have been identified in Section 3.4.5.

3.4.4.2 Electrostatic Precipitator~~ – Rule 12-16~~

Electrostatic precipitators have several advantages compared with other air pollution control devices, in part, because they are very efficient collectors, even for small particles. Further, because the collection forces act only on the particles, ESPs can treat large volumes of gas with low pressure drops. They can collect dry materials, fumes, or mists. Electrostatic precipitators can also operate over a wide range of temperatures and generally have low operating costs. There are two broad types of ESPs, dry and wet.

3.4.4.2.1 Dry ESPs

Dry ESPs remove dust from the collection electrodes by vibrating the electrodes through the use of rappers. Wire-plate dry ESPs are by far the most common design of an ESP and are used in a number of industries, including petroleum refining. Dry ESPs remove dust from the collection electrodes by vibrating the electrodes through the use of rappers. Common types of rappers are gravity impact hammers and electric vibrators. For a given ESP, the rapping intensity and frequency must be adjusted to optimize performance. Sonic energy is also used to assist dust removal in some dry ESPs. The main components of dry ESPs are an outside shell to house the unit, high voltage discharge electrodes, grounded collection electrodes, a high voltage source, a rapping system, and hoppers.

Hazards associated with dry ESPs include fire and explosion hazards that can occur at the inlet to ESPs when highly charged dust particles are transported by a gas carrier that can contain the mixtures of both incombustible and combustible flue gases. The risk of ignition and even explosion is especially high in the presence of an explosive mixture of oxygen, hydrocarbons, carbon monoxide, etc. The ignition source is typically caused by the breakdown between the corona electrode and the collecting electrode, but in some cases electrostatic discharge (typically back corona) can also act as an ignition source.

Other problems that may contribute to fire or explosion hazards include the following. Minimum clearance between electrodes may result in repeated "sparkover" causing local heating and vaporization of wires causing the wires to break. Broken wires may swing freely and cause shorting between discharge and collector electrodes. Excessive rapping may also break wires. Poor electrical alignment may cause the wire frame to oscillate fatiguing wires and increasing sparking. If high levels of carbon are known to exist on the collecting surface or in the hoppers, opening the precipitator access doors may result in spontaneous combustion of the hot dust caused by the inrush of air.

Electrostatic Precipitators or ESPs have been used in industry for over 60 years. Review of the safety record of dry ESPs over the last 20 years did not identify any explosion or fire hazards. However, in light of the fact that there is a potential for explosion or fire hazards, to be conservative it is concluded here that dry ESPs may cause or contribute to significant adverse hazard and hazardous materials impacts. Therefore, mitigation measures have been identified in Section 3.4.4.

3.4.4.2.2 Wet ESPs

The basic components of a wet ESP are the same as those of a dry ESP with the exception that a wet ESP requires a water spray system rather than a system of rappers. The gas stream is either saturated before entering the collection area or the collecting surface is continually wetted to prevent agglomerations from forming. Because the dust is removed from a wet ESP in the form of a slurry, hoppers are typically replaced with a drainage system. Wet ESPs have the following advantages over dry ESPs. Wet ESPs can adsorb gases, cause some pollutants to condense, are easily integrated with scrubbers, and eliminate re-entrainment of captured particles.

Particulates collected from wet ESPs are washed from the collection electrodes with water or another suitable liquid. Some wet ESP applications require that liquid is sprayed continuously into the gas stream; in other cases, the liquid may be sprayed intermittently. Since the liquid spray saturates the gas stream in a wet ESP, it also provides gas cooling and conditioning. Because particulates are removed from a wet ESP as a slurry, explosion hazards are unlikely (Dorman, 1974). Therefore, hazards and hazardous materials impacts from wet ESPs are concluded to be less than significant. Therefore, mitigation measures are not required.

3.4.4.3 Flue Gas Treatment ~~– Rule 12-16~~

Amine absorbers are typically used for reducing SOx emissions as part of FGT or as part of SRU/TGU systems operated at refineries. The type of amine used in these absorbers varies from process to process and sometimes the amines are paired up with a proprietary catalyst such as Merox for additional SOx control. The most common amines are DEA, MDEA, and MEA and their use is limited to removing H_2S and CO_2 from gas streams. While none of these amines can remove mercaptans, DEA and MEA can be used to remove carbonyl sulfide.

3.4.4.3.1 Amines

DEA: Of the following three amines, DEA, MDEA, and MEA, DEA is the only amine that is a TAC and carcinogenic. MDEA and MEA are not regulated substances pursuant to BAAQMD's Regulation 2-5. DEA is regulated as a hazardous compound substance pursuant to BAAQMD's Regulation 2-5. Located on the MSDS for DEA, the NFPA hazards ratings are follows: health is rated 1 (slightly hazardous), flammability is rated 1 (slightly flammable) and reactivity is rated 0 (none). Located on the MSDSs for MEA, the NFPA hazards ratings are follows: health is rated 3 (highly hazardous), flammability is rated 2 (moderately flammable) and reactivity is rated 0 (none). The NFPA has not assigned a rating for MDEA.

As previously noted, it is assumed that any affected refinery operator who installs a WGS pursuant to future Regulation 12-16 requirements, would likely use the same amines that are currently used for other refinery units or processes. In this situation, there would likely be increased throughput of the amine through the storage tank, but in the event of an accidental release, the hazard consequence would not change. Consequently, installation of a WGS using DEA, MDEA, or DEA in the amine absorber would not cause or contribute to exceedances of any applicable hazards and hazardous materials significance thresholds. Therefore, potential hazards and hazardous materials impacts from increased usage of DEA, MDEA, or DEA would be less than significant and mitigation measures are not required.

3.4.4.3.2 Merox Treatment

Merox is a proprietary caustic scrubbing technology used for removing mercaptans and residual H_2S from fuel gas. A Merox unit will typically consist of a column with three sections: 1) prewash; 2) extraction; and, 3) water wash. Feedstock enters the bottom of the column in the prewash section. The gas flows upward in the column where NaOH caustic is injected into the extraction section; the caustic acts as an absorbing agent to capture the mercaptans and convert them to sodium mercaptides. The spent caustic solution is regenerated by an oxidizer unit with catalyst injection to convert the mercaptides to disulfide oil. The disulfide oil is separated and then is typically sent elsewhere within the refinery for further processing while the regenerated caustic soda is returned to the extraction section of the column.

If a Merox system is added to an existing absorber system, it is likely that the current amine solution would continue to be used. The addition or conversion to Merox technology will increase the amount of NaOH needed at any affected refineries. The analysis for the potential increases in NaOH for a WGS system is further addressed in Subsection 3.4.4.7.1 below. Based on available information, Merox catalyst that would be needed is approximately eight pounds per day or 3,000 pounds per year for the caustic regeneration portion of the Merox process for a typical absorber system.

Merox catalyst is comprised of a proprietary, cobalt-based reagent (a trade secret cobalt phthalocyanine sulfonate compound) that contains mostly water. The MSDS for Merox catalyst indicates that none of the ingredients in the catalyst has components that are classified or regulated by OSHA or by the United States National Toxicology Program (NTP). However, all of the ingredients in the catalyst are registered on the Toxic Substances Control Act (TSCA) Chemical Substance Inventory. Cobalt compounds are also specified as toxic chemicals under SARA Section 313 and may be subject to the Toxic Release Inventory (TRI) reporting requirements under 40 CFR 372. In addition, cobalt compounds are regulated pursuant to the State of California's Proposition 65 noticing requirements. Cobalt and cobalt compounds are not regulated by BAAQMD Regulation 2-5 or CalARP. The NFPA has not assigned a rating for Merox catalyst. Finally, Merox catalyst is not listed in the U.S. EPA's RCRA regulations because it does not possess any of the four identifying characteristics of hazardous waste (e.g., ignitibility, corrosivity, reactivity or toxicity).

Implementing FGT modifications at affected refineries by installing Merox treatment systems is not expected to change the hazards profile of the affected units because Merox is not regulated as a hazardous substance. Thus, based on the preceding analysis, the hazards and hazardous materials impacts relative to the use of Merox are expected to be less than significant. Therefore, mitigation measures are not required.

3.4.4.4 Selective Catalytic Reduction ~~– Rule 12-16~~

Ammonia or urea is used to react with NOx, in the presence of a catalyst, to form nitrogen gas and water. In some SCR installations, anhydrous ammonia is used. Although ammonia is currently used in SCRs throughout the Bay Area, safety hazards related to the transport, storage, and handling of ammonia exist. Ammonia has acute and chronic non-cancer health effects and also contributes to ambient PM10 emissions under some circumstances.

Onsite Release Scenario: The use of anhydrous ammonia involves greater risk than aqueous ammonia because it is stored and transported under pressure. In the event of a leak or rupture of a tank, anhydrous ammonia is released and vaporizes into the gaseous form, which is its normal state at atmospheric pressure and produces a toxic cloud. Aqueous ammonia is a liquid at ambient temperatures and gas is only produced when a liquid pool from a spill evaporates. Under current OES regulations implementing the CalARP requirements, both anhydrous and aqueous ammonia are regulated under California Health and Safety Code Section 2770.1.

Refineries and associated facilities may choose to use SCR to comply with Rule 12-16, which will cause the increased use and storage of ammonia. All of the stationary sources are located within industrial and commercial facilities, and are expected to be located in industrial/commercial zones. However, the use and storage of anhydrous ammonia would be expected to result in significant hazard impacts as there is the potential for anhydrous ammonia to migrate off-site and expose individuals to concentrations of ammonia that could lead to adverse health impacts. Anhydrous ammonia would be expected to form a vapor cloud (since anhydrous ammonia is a gas at standard temperature and pressure) and migrate from the point of release. The number of people exposed and the distance that the cloud would travel would depend on the meteorological conditions present. Depending on the location of the spill, a number of individuals could be exposed to concentrations of ammonia that would exceed the ERPG2 concentrations.

In the event of an aqueous ammonia release, the ammonia solution would have to pool and spread out over a flat surface in order to create sufficient evaporation to produce a significant vapor cloud. For a release from onsite vessels or storage tanks, spills would be released into a containment area, which would limit the surface area of the spill and the subsequent toxic emissions. The containment area would limit the potential pool size, minimizing the amount of spilled material that would evaporate, form a vapor cloud, and impact residences or other sensitive receptors in the area of the spill. Significant hazard impacts associated with a release of aqueous ammonia would not be expected. Therefore, the use of aqueous ammonia is expected to be preferred over anhydrous ammonia.

Transportation Release Scenario: Use and transport of anhydrous ammonia involves greater risk than aqueous ammonia because it is stored and transported under pressure. In the event of a leak or rupture of a tank, anhydrous ammonia is released and vaporizes into the gaseous form, which is its normal state at atmospheric temperature and pressure, and produces a toxic cloud. Aqueous ammonia is a liquid at ambient temperatures and pressure, and gas is only produced when a liquid pool from a spill evaporates. Deliveries of ammonia would be made to each facility by tanker truck via public roads. The maximum capacity of a tanker truck is 150 barrels. Regulations for the transport of hazardous materials by public highway are described in 49 Code of Federal Regulations (CFR) 173 and 177. Nineteen percent aqueous ammonia is considered a hazardous material under 49 CFR 172.

Although trucking of ammonia and other hazardous materials is regulated for safety by the U.S. Department of Transportation, there is a possibility that a tanker truck could be involved in an accident spilling its contents. The factors that enter into accident statistics include distance traveled and type of vehicle or transportation system. Factors affecting automobiles and truck transportation accidents include the type of roadway, presence of road hazards, vehicle type, maintenance and physical condition, and driver training. A common reference frequently used in measuring risk of an accident is the number of accidents per million miles traveled. Complicating the assessment of risk is the fact that some accidents can cause significant damage without injury or fatality.

The actual occurrence of an accidental release of a hazardous material cannot be predicted. The location of an accident or whether sensitive populations would be present in the immediate vicinity also cannot be identified. In general, the shortest and most direct route that takes the least amount of time would have the least risk of an accident. Hazardous material transporters do not routinely avoid populated areas along their routes, although they generally use approved truck routes that take population densities and sensitive populations into account.

The hazards associated with the transport of regulated (CCR Title 19, Division 2, Chapter 4.5 or the CalARP requirements) hazardous materials, including ammonia, would include the potential exposure of numerous individuals in the event of an accident that would lead to a spill. Factors such as amount transported, wind speed, ambient temperatures, route traveled, and distance to sensitive receptors are considered when determining the consequence of a hazardous material spill.

In the unlikely event that the tanker truck would rupture and release the entire 150 barrels of aqueous ammonia, the ammonia solution would have to pool and spread out over a flat surface in order to create sufficient evaporation to produce a significant vapor cloud. For a road accident, the roads are usually graded and channeled to prevent water accumulation and a spill would be channeled to a low spot or drainage system, which would limit the surface area of the spill and the subsequent toxic emissions. Additionally, the roadside surfaces may not be paved and may absorb some of the spill. Without this pooling effect on an impervious surface, the spilled ammonia would not evaporate into a toxic cloud and impact residences or other sensitive receptors in the area of the spill. An accidental aqueous ammonia spill occurring during transport is, therefore, not expected to have significant impacts.

3.4.4.5 Ultracat~~ – Rule 12-16~~

Ultracat catalyst filters work similarly to SCR systems, using aqueous ammonia to react with NOx and resulting in nitrogen gas and water. As a result, the primary concern with Ultracat catalyst filters are the impacts associated with the transport, storage, and use of aqueous ammonia. The potential impacts of aqueous ammonia are previously discussed in detail in section 3.4.4 and were found not potentially significant. Thus, the same conclusion is drawn here. Ultracat catalyst filters are not expected to pose significant impacts and mitigation measures not required.

3.4.4.6 Wet Gas Scrubber ~~– Rules 11-18 and 12-16~~

3.4.4.6.1 Caustic

For any operators at potentially affected facilities who choose to install a WGS, hazardous materials may be needed to operate the WGSs depending on the source category. Caustic is a key ingredient needed for the operation of a WGS; it is the most widely used substance for several SOx control applications spanning multiple equipment/source categories. While there are several types of caustic solutions that can be used in WGS operations, caustic made from sodium hydroxide (NaOH) is most commonly used for WGSs for FCCUs and coke calciners.

NAOH: NaOH, used as caustic in a WGS, is a toxic air contaminant; it is also a noncancerous but acutely hazardous substance. Located on the MSDS for NaOH (50 percent by weight), the hazards ratings are as follows: health is rated 3 (highly hazardous, flammability is rated 0 (none), and reactivity is rated 1 (slightly hazardous). Use of NaOH caustic in a WGS would most likely occur at refineries that already use and store NAOH caustic for other purposes. Otherwise, the facility would need to construct a new NAOH caustic storage tank and ancillary piping and other associated equipment.

Soda Ash: For WGSs that may be installed to control SOx from SRU/TGUs, the caustic used in the WGS is made from soda ash, instead of NaOH. Soda ash is the common name for sodium carbonate (Na2CO3), a non-toxic, non-cancerous, and non-hazardous substance. Located on the

MSDS for Na2CO3, the hazards ratings are as follows: health is rated 2 (moderate), flammability is rated 0 (none) and reactivity is rated 0 (none).

Based on the above information, additional use of caustic in a WGS would not cause or contribute to exceedances of any applicable hazards and hazardous materials significance thresholds.

3.4.4.7 Releases During Transport ~~– Rules 11-18 and 12-16~~

3.4.4.7.1 Selective Oxidation Catalyst

A typical SRU/TGU system is not expected to require more than several hundred pounds of catalyst modules per year. As a result, delivery of catalyst modules can be accomplished in one truck trip. Based on their chemical properties, sulfur oxidation catalysts are not expected to pose significant adverse health or physical hazard impacts during use. Similarly, significant adverse hazards and hazardous materials impacts during use or transport of new catalysts to a facility or transport of spent catalysts for recycling are expected to be less than significant because of they do not pose adverse health or physical hazard impacts and, in the event of an accidental release, the modules would be easily contained and cleaned up.

3.4.4.7.2 Wet Gas Scrubber

Installation of a WGS would require deliveries of fresh caustic, either NaOH or soda ash. If an accidental release of caustic during transport occurs, potentially significant adverse hazards or hazardous materials impacts may be generated.

NaOH: Deliveries of NaOH (50 percent by weight) are typically made by tanker truck via public roads. The maximum capacity of one NaOH tanker truck is approximately 6,000 gallons. The projected consumption rates of NaOH are assumed to range from approximately 160 tons per year (T/Y) (0.44 tons per day (T/D)) to 1,228 T/Y (3.37 T/D) based on an analysis of WGS for refineries in southern California (SCAQMD, 2008). Based on worst-case assumptions, an affected refinery would need up to an additional 32 truck trips of NaOH caustic per year[1]. Although some of the affected refineries currently receive NaOH caustic, it is likely that they receive shipments periodically throughout the year rather than on a daily basis. Therefore, it is unlikely that an affected refinery would require one delivery per day in addition to any existing deliveries of NaOH caustic, instead it is likely that NaOH deliveries would occur on more days per year. Operators of trucks that transport hazardous materials by public highway are required to comply with requirements described in 49 CFR §§ 173 and 177. Hazardous materials impacts during the transport of NaOH caustic are considered to be less than significant. ~~Facilities affected by Rule 11-18 may also use WGS; the associated hazardous materials impacts are expected to be less than the worst case scenario analyzed above for petroleum refineries and are thus found to be less than significant.~~

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[1] Annual NaOH deliveries are calculated based on one delivery truck holding 6,000 gallons per truck load. For example, 1,228 T/Y NaOH x 2,000 lbs/ ton = 2,465.000 lbs/yr x 1 gal NaOH @ 50%/12.77 lbs = 192,000 gal/year x 1 truck/6,000 gallons = 32 trucks/year

Soda Ash: Additional soda ash, catalyst and SOx reducing additives could be delivered to some of the affected facilities in the future, but no increase in transportation hazards is expected as none of these materials are considered to be hazardous.

Based on the above information, accidental releases of caustic during transport would not cause or contribute to exceedances of any applicable hazards and hazardous materials significance thresholds.

3.4.5 MITIGATION MEASURES

3.4.5.1 Baghouses

To reduce potential fire or explosion impacts from baghouses, the following mitigation measures are required.

HHM-1 Maintain a comprehensive dust control program, with hazard dust inspections, testing, housekeeping, and control initiatives.

HHM-2 Ground the filter elements using grounding wires, rods, etc., to prevent sparks that could be generated during cleaning.

HHM-3 Install additional explosion rupture panels and vent outdoors

HHM-4 If the collector filters are to be replaced the first procedure is to remove as much flammable or explosive dusts from the filters as possible. Reverse the exhaust fan's direction to maintain a low flow and prevent dust from returning to the hood. Clean the collector one section at a time allowing time for the dust to settle into the collection hopper. After several complete cleaning cycles a large portion of the dust will be ejected, which is expected to lower the exposure of the worker in handling the filter elements.

HHM-5 Perform all hot work (welding, acetylene cutting, grinding, etc.) away from the collector, if possible.

HHM-6 Ensure that power tools and impact hand tools (such as hammers, chippers, etc.) used by maintenance personnel that could present a sparking hazard are not used in high dust concentrations. When such work is being performed on the structure itself, make certain the dust concentrations within the enclosure are well below combustible levels.

HHM-7 Ensure adherence to National Fire Protection Agency (NFPA) standards including, but not limited to, NFPA 499, Recommended Practice for the Classification of Combustible Dusts and of Hazardous (classified) Locations for Electrical Installations in Chemical Process Areas

Implementing the above mitigation measures is expected to ensure that hazard and hazardous materials impacts would not exceed any applicable hazards and hazardous materials significance thresholds, therefore, hazards and hazardous materials impacts from baghouses are concluded to be less than significant.

3.4.5.2 Dry Electrostatic Precipitators

Research of dry ESPs over the last 20 years has shown that this type of air pollution control equipment is generally safe to use. However, to ensure that potential fire and explosion risks are less than significant, the following safety mitigation measures have been identified.

HHM-8 Fire and explosion risks can be reduced by equipping dry ESPs with CO sensors that send a signal to a safety system to stop the process when CO concentrations exceed the critical limit. This solution reduces the risk dramatically.

HHM-9 Modern digital electronic controls shall be used to automate this process to assure the dry ESP operates at peak performance levels at all times.

HHM-10 The bottom and top of each wire should be covered with shrouds to help minimize sparking and metal erosion at these points.

HHM-11 To further reduce fire and explosion hazards, affected refinery operators shall establish the inspection frequency of all dry ESP components through a formal in-house maintenance procedure. Vendors' recommendations for an inspection schedule shall be followed and shall include at a minimum, the following procedures.

Daily: On a daily basis operation of hoppers and ash removal system should be checked; the control room ventilation system should be examined; any abnormal arcing in the ESP enclosure and ducts (typically caused by broken wires, which may swing freely causing shorting between discharge and collector electrodes) should be investigated; and electrodes should be checked.

Weekly: Air filters should be checked and cleaned on a weekly or more frequently.

Semianually: On a semiannual basis the operator should check the exterior for visual signs of deterioration, and abnormal vibration, noise, or leaks.

Implementing the above mitigation measures is expected to ensure that hazard and hazardous materials impacts would not exceed any applicable hazards and hazardous materials significance thresholds, therefore, hazards and hazardous materials impacts from dry ESPs are concluded to be less than significant.

3.4.6 SIGNIFICANCE CONCLUSION AND REMAINING IMPACTS

~~3.4.6.1 Implementation of Rule 11-18~~

~~With the exception of baghouses, the hazard impacts associated with the installation of air pollution control equipment under Rule 11-18 are expected to be less than significant without mitigation. For baghouses, feasible mitigation measures pursuant to CEQA Guidelines §15126.4 have been identified and are described in Chapter 3.4.5.1. The hazard impacts under implementation of Rule 11-18 are expected to be less than significant following mitigation.~~

3.4.6.1 Implementation of Rule 12-16

Installation of most types of air pollution control equipment is not expected to cause or contribute to significant adverse hazard impacts, with exception of baghouses or dry ESPs. As a result, feasible mitigation measures pursuant to CEQA Guidelines §15126.4 have been identified and are described in Chapter 3.4.5. The hazard impacts under implementation of Rule 12-16 are expected to be less than significant following mitigation.

~~3.4.6.3 Implementation of Both Rules 11-18 and 12-16~~

~~Assuming the adoption of both rules, it would be expected that more air pollution control equipment would be required to be installed as additional TAC emissions would be controlled, as well as additional refineries emissions may also be required to be controlled. As discussed in Chapter 3.4.4 the previous, installation of most air pollution control equipment would not generate additional hazard impacts. The potentially adverse hazard impacts associated with the installation of baghouses and ESPs are expected to be less than significant after mitigation.~~

3.4.7 CUMULATIVE IMPACTS

As concluded in the above hazards and hazardous materials analysis, installation of most types of air pollution control equipment, if required in the future, is not expected to cause or contribute to significant adverse hazard impacts, with the exception of baghouses or dry ESPs. As a result, feasible mitigation measures pursuant to CEQA Guidelines §15126.4 have been identified and were described. Implementing the mitigation measures identified in Sections 3.4.5.1 and 3.4.5.2 is expected to reduce significant adverse hazards and hazardous materials impacts to less than the applicable hazards and hazardous materials significance thresholds. Therefore, overall hazards and hazardous materials impacts, including accidental releases of hazardous materials during transport, were concluded to be less than significant. Because hazards and hazardous materials impacts do not exceed the applicable hazards and hazardous materials significance thresholds, they are not considered to be cumulatively considerable (CEQA Guidelines §15064 (h)(1)) and, therefore are not expected to generate significant adverse cumulative hazards and hazardous materials impacts.

The 2017 Clean Air Plan contains a total of 85 control measures that the District intends to impose to improve overall air quality in the District. Control measures in the 2017 Clean Air Plan included Rule 12-16 as well as a number of other control measures to control emissions from refineries as well as other stationary sources and transportation control measures. The 2017 Clean Air Plan is expected to result in overall reductions in VOC, NOx, SOx, and PM emissions, providing an air quality benefit (BAAQMD, 2017). The Final EIR for the 2017 Air Plan evaluated the potential hazard impacts associated with implementation of the 85 control measures and concluded that the

2017 Plan is not expected to introduce any new hazards into the Bay Area. The impacts on hazards and hazardous materials were concluded to be less than significant. Further, the 2017 Plan is expected to result in a reduction in the use of fossil fuels which will also reduce the potential hazards and hazardous materials spills. Therefore, hazards and hazardous materials impacts associated with the 2017 Plan (including Control Measure SS11 Petroleum Refining Facility-Wide Emission Limits, which is proposed Rule 12-16) are not cumulatively significant and would not make a considerable contribution to an existing cumulatively significant hazardous or hazardous materials impacts (BAAQMD, 2017).

CHAPTER 3.3

GREENHOUSE GAS EMISSIONS

3.3 GREENHOUSE GAS EMISSIONS

This subchapter of the EIR evaluates the potential greenhouse gas (GHG) impacts associated with implementation of Rule~~s 11-~~18 and/or 12-16. ~~Rule 11-18 would reduce exposure to TAC emissions from a number of stationary sources within the Bay Area, including refineries.~~ Rule 12-16 would establish numeric emission limits on specific refinery and associated facilities within the Bay Area.

As discussed in the Initial Study, implementation ~~of Rule 11-18 would reduce risk from facilities that emit toxic air contaminants throughout the Bay Area. However, certain risk reduction measures have the potential to increase emissions of other pollutants, such as GHGs and criteria pollutants. Implementation~~ of Rule 12-16 would prevent refinery emissions of GHGs and some criteria pollutants from increasing. Similarly, secondary adverse air quality impacts could occur from installing control equipment at individual refineries in response to changes that could increase emissions some of criteria pollutants. Adverse impacts include increased GHG emissions associated with construction activities and combustion sources from certain types of air pollution control equipment. The NOP/IS (see Appendix A) determined that potential GHG impacts associated with implementation of the proposed new rules are potentially significant. In addition, Rule 12-16 would establish GHG emission limits at refineries and could conflict with CARB's AB32 Cap and Trade program. Project-specific and cumulative adverse GHG impacts associated with the proposed new rule have been evaluated in Chapter 3.3 of this EIR.

3.3.1 INTRODUCTION

Global climate change refers to changes in average climatic conditions on the earth as a whole, including: temperature, wind patterns, precipitation and storms. Global warming, a related concept, is the observed increase in the average temperature of the earth's surface and atmosphere. One identified cause of global warming is an increase of GHGs in the atmosphere. The six major GHGs identified by the Kyoto Protocol are CO_2, methane (CH_4), nitrous oxide (N_2O), sulfur hexafluoride (SF_6), haloalkanes (HFCs), and perfluorocarbons (PFCs). Although not included among the Kyoto Six GHGs, black carbon, a key component of fine PM, has been identified as a potent agent of climate change. Black carbon is the third largest GHG in the Bay Area on a carbon dioxide equivalence (CO2e) basis. Diesel engines and wood-burning are key sources of black carbon in the Bay Area.

The GHGs absorb longwave radiant energy reflected by the earth, which warms the atmosphere. GHGs also radiate longwave radiation both upward to space and back down toward the surface of the earth. The downward part of this longwave radiation absorbed by the atmosphere is known as the "greenhouse effect."

While the cumulative impact of GHG emissions is global, the geographic scope of this cumulative impact analysis is the State of California. The analysis of GHG emissions is a different analysis than for criteria pollutants for the following reasons. For criteria pollutants, significance thresholds are based on daily emissions because attainment or non-attainment is typically based on daily exceedances of applicable ambient air quality standards. Further, the ambient air quality standards for criteria pollutants are based on relatively short-term exposure effects to human health, e.g., one-hour and eight-hour. Using the half-life of CO_2, 100 years, for example, the effects of GHGs are longer-term, affecting the global climate over a relatively long time frame.

It is the increased accumulation of GHGs in the atmosphere that may result in global climate change. Climate change involves complex interactions and changing likelihoods of diverse impacts. Due to the complexity of conditions and interactions affecting global climate change, it is not possible to predict the specific impact, if any, attributable to GHG emissions associated with a single project, which is why GHG emission impacts are considered to be a cumulative impact.

Emissions of GHGs, especially combustion of fossil fuels for energy, transportation, and manufacturing, contribute to warming of the atmosphere that may cause rapid changes in the way a number different types of ecosystems typically function. For example, in some regions, changing precipitation or acceleration of melting snow and ice are altering hydrological systems, affecting water resources in terms of quantity and quality. Melting glaciers and polar ice sheets are expected to contribute to sea level rise. Rising sea levels are expected to contribute to an increase in coastal flooding events.

A warmer atmosphere could also contribute to chemical reactions increasing the formation of ground-level ozone. Ozone is a well-known lung irritant and a major trigger of respiratory problems like asthma attacks. Local changes in temperature and rainfall could alter the distribution of some waterborne illnesses and disease vectors. For example, warmer freshwater makes it easier for pathogens to grow and contaminate drinking water.

Potential health effects from global climate change may arise from temperature increases, climate-sensitive diseases, extreme events, and air quality. There may be direct temperature effects through increases in average temperature leading to more extreme heat waves and less extreme cold spells. Those living in warmer climates are likely to experience more stress and heat-related problems (i.e., heat rash and heat stroke). In addition, climate sensitive diseases may increase, such as those spread by mosquitoes and other disease carrying insects. Those diseases include malaria, dengue fever, yellow fever, and encephalitis. Extreme events such as flooding and hurricanes can displace people and agriculture, which would have negative consequences. Drought in some areas may increase, which would decrease water and food availability. Global climate change may also exacerbate air quality problems from increased frequency of exceeding criteria pollutant ambient air quality standards.

This chapter analyzes how implementation of Rule~~s 11-18 and/or~~ 12-16 may contribute to global climate change through increased GHG emissions.

3.3.2 ENVIRONMENTAL SETTING

There are dozens of GHGs, but a subset of these gases are the primary agents of climate change. The six major GHGs identified by the Kyoto Protocol plus black carbon are the GHGs considered in the 2017 Plan.

> **Carbon Dioxide** (CO_2) is released to the atmosphere when fossil fuels (oil, gasoline, diesel, natural gas, and coal), solid waste, and wood or wood products are burned.
>
> **Methane** (CH_4) is emitted during the production and transport of coal, natural gas, and oil. Methane emissions also result from the decomposition of organic waste in municipal solid waste landfills and the raising of livestock.
>
> **Nitrous oxide** (N_2O) is emitted during agricultural and industrial activities, as well as during combustion of solid waste and fossil fuels.
>
> **Hydrofluorocarbons** (HFCs), **perfluorocarbons** (PFCs), and **sulfur hexafluoride** (SF_6), are generated by a variety of industrial processes. Emissions of these fluorinated gases (F-gases) are small on a mass basis, but they are potent agents of climate change on a per unit basis.
>
> **Black Carbon**: Although not included among the Kyoto Six GHGs, black carbon is a key component of fine particulate matter and has been identified as a potent agent of climate change. Black carbon is the third largest GHG in the Bay Area on a CO_2-equivalent basis. Diesel engines and wood-burning are key sources of black carbon in the Bay Area. Since exposure to fine PM has a wide range of health impacts, reducing emissions of black carbon will provide important public health co-benefits.

Table 3.3-1 shows atmospheric lifespan, 20-year and 100-year GWP values, and key emission sources for the GHGs.

An emissions inventory is a detailed estimate of the amount of air pollutants discharged into the atmosphere of a given area by various emission sources during a specific time period. The emission inventory in Table 3.3-2 focuses on GHG emissions due to human activities in the State of California. In 2014, total GHG emissions were 441.5 million metric tons of CO2 equivalent (MMTCO2e), a decrease of 3.51 MMTCO2e compared to 2010.

TABLE 3.3-1

Greenhouse Gases Addressed in the 2016 Plan

Greenhouse Gas	Atmospheric Lifespan	GWP * (20-year timeframe)	GWP * (100-year timeframe)	Key Emissions Sources
Carbon dioxide (CO_2)	20-200 years	1	1	Fossil fuel combustion
Nitrous oxide (N_2O)	114 years	268	298	Motor vehicles, agriculture, water treatment, composting
Methane (CH_4)	12 years	86	34	Natural gas production & distribution, solid waste disposal, ranching, dairies
Hydrofluorocarbons (HFCs)	1.5 to 264 years	506 to 6,940	138 to 8,060	Refrigeration, air conditioning
Perfluorocarbons (PFCs)	3,000 years or more	6,500	6,500	Semiconductor manufacturing
Sulfur Hexafluoride (SF_6)	3,200 years	17,500	23,500	Electricity grid losses
Black Carbon**	Days to weeks	3,235	900	Diesel engines, wood-burning

* The GWP values in Table 3.3-1 are taken from the IPCC 5th Assessment Report (AR5), with the exception of black carbon.

** The black carbon values are based on from US EPA report on black carbon: https://www3.epa.gov/blackcarbon/2012report/Chapter2.pdf

TABLE 3.3-2

California Greenhouse Gas Emission and Sinks Summary (million metric tons CO2e)

Categories Included in the Inventory	2004	2010	2014
ENERGY	**427.53**	**378.67**	**367.71**
Fuel Combustion Activities	**420.08**	**370.95**	**359.87**
Energy Industries	172.76	144.85	139.95
Manufacturing Industries & Construction	19.52	18.72	20.28
Transport	181.43	161.84	158.62
Other Sectors	46.37	45.55	41.02
Fugitive Emissions from Fuels	**7.45**	**7.72**	**7.84**
Solid Fuels	0.04	0.02	0.02
Oil and Natural Gas	6.18	6.53	6.89
Geothermal Energy Production	1.12	1.10	0.92
Pollution Control Devices	0.11	0.06	0.00
INDUSTRIAL PROCESSES & PRODUCT USE	**19.81**	**22.40**	**30.24**
Mineral Industry	6.11	3.49	5.32
Chemical Industry	0.05	0.05	0.01
Metal Industry	0.07	0.07	0.06
Non-Energy Products from Fuels & Solvent Use	2.65	2.47	2.38
Electronics Industry	0.35	0.20	0.26
Product Uses as Substitutes for Ozone Depleting Substances	6.37	11.93	16.76
Other Product Manufacture & Use Other	0.90	0.82	0.72
Other	3.31	3.36	4.73
AGRICULTURE, FORESTRY, & OTHER LAND USE	**30.62**	**33.51**	**32.85**
Livestock	20.81	24.00	23.81
Aggregate Sources & Non-CO_2 Emissions Sources on Land	9.80	9.51	9.04
WASTE	**9.67**	**10.48**	**10.73**
Solid Waste Disposal	7.42	8.11	8.28
Biological Treatment of Solid Waste	0.33	0.47	0.57
Wastewater Treatment & Discharge	1.92	1.90	1.88
Included California Emissions	**487.63**	**445.05**	**441.54**

Source: 2016 Edition California GHG Inventory for 2000-2014 by IPCC (CARB, 2016)

Table 3.3-3 presents the GHG emission inventory by major source categories in calendar year 2015, as identified in the Air District's 2017 Air Plan (BAAQMD, 2017). Transportation sources generate approximately 40 percent of the total GHG emissions in the District. The remaining 60 percent of the total District GHG emissions are from stationary and area sources. Approximately 16 percent of the total District GHG emissions are from refineries.

TABLE 3.3-3

2015 BAAQMD Greenhouse Gas Emission Inventory (metric tons of CO2e)

Source Category	CO2, CH4, N2O, HFC/PFC, SF6	Black Carbon	Total Emissions (CO2e)
Transportation	**35,040,000**	**770,000**	**35,810,000**
On-road	30,480,000	310,000	30,790,000
Off-road	4,560,000	460,000	5,020,000
Electricity/Co-Generation	**15,790,000**	**130,000**	**15,920,000**
Co-Generation	6,790,000	90,000	6,880,000
Electricity Generation	6,210,000	40,000	6,250,000
Electricity Imports	2,790,000	-	2,790,000
Buildings	**9,870,000**	**400,000**	**10,270,000**
Residential Fuel Usage	6,460,000	220,000	6,680,000
Commercial Fuel Usage	3,410,000	180,000	3,590,000
Stationary Sources	**20,840,000**	**340,000**	**21,180,000**
Oil Refineries	14,240,000	210,000	14,450,000
General Fuel Usage	5,880,000	130,000	6,010,000
Fugitive/Process Emissions	720,000	4,000	724,000
Waste Management	**2,480,000**	**23,000**	**2,503,000**
Landfills	2,050,000	22,000	2,072,000
Composting/POTWs	430,000	1,000	431,000
High-GWP Gases	**2,790,000**	**-**	**2,790,000**
HFCs and PFCs	2,740,000	-	2,740,000
SF6	50,000	-	50,000
Agriculture	**1,180,000**	**170,000**	**1,350,000**
Agricultural Equipment	180,000	43,000	223,000
Animal Waste	720,000	16,000	736,000
Soil Management	270,000	1,000	271,000
Biomass Burning	10,000	110,000	120,000
Total Emissions	**87,990,000**	**1,833,000**	**89,823,000**

Source: BAAQMD, 2017 ~~2015~~

The emission inventory in Table 3.3-3 focuses on GHG emissions projections due to human activities only, and compiles emission estimates that result from industrial, commercial, transportation, domestic, forestry, and agriculture activities in the San Francisco Bay Area region of California. The GHG emission inventory reports direct emissions generated from sources within the District. The report does not include indirect emissions, for example, a source using electricity has no direct emissions because emissions are emitted at the power plants. Emissions of CO_2, CH_4, N_2O, HFCs, PFCs, and SF_6 are estimated using the most current activity and emission factor data from various sources. Emission factor data was obtained from the U.S. Department of Energy's (DOE's) Energy Information Administration (EIA), the CEC, and CARB.

Under "business as usual" conditions, GHG emissions are expected to grow in the future due to population growth and economic expansion. Table 3.3-4 shows emissions trends by major sources for the period 1990 to 2020.

TABLE 3.3-4

Bay Area GHG Emission Trends by Major Sources
(Million metric Tons CO_2 - Equivalent)

Category	1990	2008	2011	2014	2017	2020
Transportation	28.6	34.8	34.3	33.9	32.5	30.4
Industry/Commercial	21	28.9	31	32.6	34.3	36
Electricity/Co-Gen.	8.4	13.9	12.1	12.9	12.6	12.3
Residential Fuel	7	6.5	6.6	6.7	6.8	6.9
Off-Road Equipment	0.9	1.4	1.3	1.3	1.4	1.3
Agriculture	1.2	1.3	1.3	1.3	1.3	1.3
Total	67.1	86.8	86.6	88.7	88.8	88.2

Source: Bay Area Emission Inventory Summary Report: Greenhouse Gases. (BAAQMD, 2015a)

Greenhouse gas emissions in Table 3.3-4 are projected based on estimated growth in various source categories. For example, CARB's EMFAC2011 and OFFROAD2007 computer models were utilized to project GHG emissions from transportation sources. In these models, fuel consumption estimates were based on the anticipated change of fleet mix and the growth of various types of on-road and off-road vehicles. Growth in vehicle miles traveled is based on the MTC's Regional Transportation Plan (RTP2030). For aircraft categories, the fleet mix, activity, and growth data are based on information from the Bay Area airports in combination with the MTC's Regional Airport System Planning Analysis: 2011 Update and the Federal Aviation Administration's (FAA's) 2010 Terminal Area Forecast reports (BAAQMD 2015a).

The GHG projections from other major sources such as landfills, natural gas fuel distribution, and cement manufacturing were estimated by using 2009 Association of Bay Area Government's employment and population data. California Integrated Waste Management data were also considered in the landfill projection process. This GHG emission inventory will be updated as additional information about activity data, emission factors and other inputs becomes available (BAAQMD, 2015a).

3.3.3 REGULATORY SETTING

3.3.3.1 Federal Regulations

Greenhouse Gas Endangerment Findings: On December 7, 2009, the U.S. EPA Administrator signed two distinct findings regarding greenhouse gases under section 202(a) of the CAA. The Endangerment Finding stated that CO_2, CH_4, N_2O, HFCs, PFCs, and SF_6 taken in combination endanger both the public health and the public welfare of current and future generations. The Cause or Contribute Finding stated that the combined emissions from motor vehicles and motor vehicle engines contribute to the GHG emissions that endangers public health and welfare. These findings were a prerequisite for implementing GHG standards for vehicles. The U.S. EPA and the National Highway Traffic Safety Administration (NHTSA) finalized emission standards for light-duty vehicles in May 2010 and for heavy-duty vehicles in August of 2011.

Renewable Fuel Standard: The RFS program was established under the Energy Policy Act (EPAct) of 2005, and required 7.5 billion gallons of renewable-fuel to be blended into gasoline by 2012. Under the Energy Independence and Security Act (EISA) of 2007, the RFS program was expanded to include diesel, required the volume of renewable fuel blended into transportation fuel be increased from nine billion gallons in 2008 to 36 billion gallons by 2022, established new categories of renewable fuel and required the U.S. EPA to apply lifecycle GHG performance threshold standards so that each category of renewable fuel emits fewer greenhouse gases than the petroleum fuel it replaces. The RFS is expected to reduce greenhouse gas emissions by 138 million metric tons, about the annual emissions of 27 million passenger vehicles, replacing about seven percent of expected annual diesel consumption and decreasing oil imports by $41.5 billion.

GHG Tailoring Rule: On May 13, 2010, U.S. EPA finalized the Tailoring Rule to phase in the applicability of the PSD and Title V operating permit programs for GHGs. The rule was tailored to include the largest GHG emitters, while excluding smaller sources (restaurants, commercial facilities and small farms). The first step (January 2, 2011 to June 30, 2011) addressed the largest sources that contributed 65 percent of the stationary GHG sources. Title V GHG requirements were triggered only when affected facility owners/operators were applying, renewing or revising their permits for non-GHG pollutants. PSD GHG requirements were applicable only if sources were undergoing permitting actions for other non-GHG pollutants and the permitted action would increase GHG emission by 75,000 metric tons of CO2e per year or more.

On June 23, 2014, the U.S. Supreme Court issued its decision in Utility Air Regulatory Group v. EPA, 134 S.Ct. 2427 (2014). The Court held that U.S. EPA may not treat GHGs as an air pollutant for purposes of determining whether a source is a major source required to obtain a PSD or Title V permit. The Court also held that PSD permits that are otherwise required to be subject to PSD (based on emissions of other pollutants) may continue to require limitations on GHG emissions based on the application of BACT. In accordance with the Supreme Court decision, on April 10, 2015, the D.C. Circuit issued an amended judgment in Coalition for Responsible Regulation, Inc. v. Environmental Protection Agency, Nos. 09-1322, 10-073, 10-1092 and 10-1167 (D.C. Cir. April 10, 2015), which, among other things, vacated the PSD and Title V regulations under review in that case to the extent that they require a stationary source to obtain a PSD or Title V permit solely because the source emits or has the potential to emit GHGs above the applicable major source thresholds.

GHG Reporting Program: U.S. EPA issued the Mandatory Reporting of Greenhouse Gases Rule (40 CFR Part 98) under the 2008 Consolidated Appropriations Act. The Mandatory Reporting of Greenhouse Gases Rule requires reporting of GHG data from large sources and suppliers under the Greenhouse Gas Reporting Program. Suppliers of certain products that would result in GHG emissions if released, combusted or oxidized; direct emitting source categories; and facilities that inject CO_2 underground for geologic sequestration or any purpose other than geologic sequestration are included. Facilities that emit 25,000 metric tons or more per year of GHGs in CO_2 equivalents (CO2e) are required to submit annual reports to U.S. EPA. For the 2014 calendar year, there were over 8,000 entities that reported 3.20 billion metric tons of GHG emissions under this program. CO_2 emissions accounted for the largest share of direct emissions with 91.5 percent, followed by methane with seven percent, and nitrous oxide and fluorinated gases representing the remaining 1.5 percent (U.S. EPA, 2016a).

National Program to Improve Fuel Economy: On September 15, 2009, the NHTSA and U.S. EPA announced a proposed joint rule that would explicitly tie fuel economy to GHG emissions reductions requirements. The proposed new corporate average fuel economy (CAFÉ) Standards would cover automobiles for model years 2012 through 2016, and would require passenger cars and light trucks to meet a combined, per mile, carbon dioxide emissions level. It was estimated that by 2016, this GHG emissions limit could equate to an overall light-duty vehicle fleet average fuel economy of as much as 35.5 miles per gallon. The proposed standards required model year 2016 vehicles to meet an estimated combined average emission level of 250 grams of carbon dioxide per mile under EPA's GHG program. On November 16, 2011, EPA and NHTSA issued a joint proposal to extend the national program of harmonized GHG and fuel economy standards to model year 2017 through 2025 passenger vehicles. In August 2012, the President of the United States finalized standards that will increase fuel economy to the equivalent of 54.5 mpg for cars and light-duty trucks by Model Year 2025.

Clean Power Plan: On August 3, 2015, the President of the United States and the U.S. EPA announced the Clean Power Plan. The Clean Power Plan sets achievable standards to reduce carbon dioxide emissions by 32 percent from 2005 levels by 2030. This Plan establishes final emissions guidelines for states to follow in developing plans to reduce GHG emissions from existing fossil fuel-fired electric generating units (EGUs). Specifically, the U.S. EPA established: (1) carbon dioxide emission performance rates representing the best system of emission reduction (BSER) for two subcategories of existing fossil fuel-fired EGUs, fossil fuel-fired electric utility steam generating units and stationary combustion turbines; (2) state-specific carbon dioxide goals reflecting the carbon dioxide emission performance rates; and (3) guidelines for the development, submittal and implementation of state plans that establish emission standards or other measures to implement the carbon dioxide emission performance rates, which may be accomplished by meeting the state goals. This final rule will continue progress already under way to reduce carbon dioxide emissions from the utility power sector in the U.S. In February 2016, the U.S. Supreme Court issued a stay of this rule pending final determination on litigation challenging the rule.

Planning for Federal Sustainability in the Next Decade: Published June 10, 2015, Executive Order 13693, *Planning for Federal Sustainability in the Next Decade*, revokes multiple prior Executive Orders and memorandum. The Executive Order outlines goals for federal agencies in the areas of energy, climate change, water use, vehicle fleets, construction, and acquisition. The goal is to maintain federal leadership in sustainability and GHG emission reductions. Federal agencies shall, where life-cycle cost-effective, beginning in fiscal year 2016:

- Reduce agency building energy intensity as measured in Btu/ft2 by 2.5 percent annually through 2025.
- Improve data center energy efficiency at agency buildings.
- Ensure a minimum percentage of total building electric and thermal energy shall be from clean energy sources.
- Improve agency water use efficiency and management (including stormwater management).
- Improve agency fleet and vehicle efficiency and management by achieving minimum percentage GHG emission reductions.

3.3.3.2 State Regulations

Executive Order S-3-05: In June 2005, then Governor Schwarzenegger signed Executive Order S-3-05, which established GHG emission reduction targets. The goals would reduce GHG emissions to 2000 levels by 2010, then to 1990 levels by 2020, and to 80 percent below 1990 levels by 2050.

AB 32: Global Warming Solutions Act: On September 27, 2006, AB 32, the California Global Warming Solutions Act of 2006. AB 32 expanded on Executive Order S-3-05. The legislature stated that "global warming poses a serious threat to the economic well-being, public health, natural resources, and the environment of California." AB 32 established a program to limit GHG emissions from major industries that includes penalties for non-compliance. While acknowledging that national and international actions will be necessary to fully address the issue of global warming, AB 32 lays out a program to inventory and reduce GHG emissions in California and from power generating facilities located outside the state that serve California residents and businesses.

Authorized by AB 32, the Cap and Trade program is one of several strategies that California uses to reduce GHG emissions. CARB adopted the California Cap and Trade program final regulations on October 20, 2011, and adopted amended regulations on September 12, 2012, with the first auction for GHG allowances on November 14, 2012. Funds received from the program are deposited into the Greenhouse Gas Reduction Fund and appropriated by the Legislature. It sets a GHG emissions limit that will decrease by two percent each year until 2015, and then three percent from 2015 to 2020 to achieve the goals in AB 32. The program initially applies to large electric power plants and large industrial plants, and included fuel distributors in 2015. These rules encompass 85 percent of all of California's GHG emissions.

SB 97 - CEQA: Greenhouse Gas Emissions: On August 24, 2007, Governor Schwarzenegger signed into law Senate Bill (SB) 97 – CEQA: Greenhouse Gas Emissions stating, "This bill advances a coordinated policy for reducing greenhouse gas emissions by directing the Office of Planning and Research (OPR) and the Resources Agency to develop CEQA guidelines on how state and local agencies should analyze, and when necessary, mitigate greenhouse gas emissions." OPR's amendments provided guidance to public agencies regarding the analysis and mitigation of the effects of GHG emissions in draft CEQA documents. The amendments did not establish a threshold for significance for GHG emissions. The amendments became effective on March 18, 2010.

Office of Planning and Research Technical Advisory on CEQA and Climate Change: Consistent with SB 97, on June 19, 2008, OPR released its "Technical Advisory on CEQA and Climate Change," which was developed in cooperation with the Resources Agency, Cal/EPA, and CARB. According to OPR, the "Technical Advisory" offers informal interim guidance regarding the steps lead agencies should take to address climate change in their CEQA documents, until CEQA guidelines are developed pursuant to SB 97 on how state and local agencies should analyze, and when necessary, mitigate greenhouse gas emissions.

According to OPR, lead agencies should determine whether greenhouse gases may be generated by a proposed project, and if so, quantify or estimate the GHG emissions by type and source. Second, the lead agency must assess whether those emissions are individually or cumulatively significant. When assessing whether a project's effects on climate change are "cumulatively considerable" even though the GHG contribution of the project may be individually limited, the lead agency must consider the impact of the project when viewed in connection with the effects of past, current, and probable future projects. Finally, if the lead agency determines that the GHG emissions from the project as proposed are potentially significant, it must investigate and implement ways to avoid, reduce, or otherwise mitigate the impacts of those emissions.

AB 1493 Vehicular Emissions: Carbon Dioxide: Prior to the U.S. EPA and NHTSA joint rulemaking, the Governor signed AB 1493 (2002). AB 1493 requires that CARB develop and adopt, by January 1, 2005, regulations that achieve "the maximum feasible reduction of greenhouse gases emitted by passenger vehicles and light-duty trucks and other vehicles determined by CARB to be vehicles whose primary use is noncommercial personal transportation in the state."

CARB originally approved regulations to reduce GHGs from passenger vehicles in September 2004, with the regulations that apply to 2009 and later model year vehicles. California's first request to the U.S. EPA to implement GHG standards for passenger vehicles was made in December 2005 and denied in March 2008. The U.S. EPA then granted California the authority to implement GHG emission reduction standards for new passenger cars, pickup trucks and sport utility vehicles on June 30, 2009.

On April 1, 2010, CARB filed amended regulations for passenger vehicles as part of California's commitment toward the National Program to reduce new passenger vehicle GHGs from 2012 through 2016. The amendments will prepare California to harmonize its rules with the federal Light-Duty Vehicle GHG Standards and CAFÉ Standards (discussed above).

Senate Bill 1368 (2006): SB 1368 is the companion bill of AB 32 and was signed by Governor Schwarzenegger in September 2006. SB 1368 required the California Public Utilities Commission (PUC) to establish a greenhouse gas emission performance standard for baseload generation from investor owned utilities by February 1, 2007. The California Energy Commission (CEC) was required to establish a similar standard for local publicly owned utilities by June 30, 2007. These standards cannot exceed the greenhouse gas emission rate from a baseload combined-cycle natural gas fired plant. The legislation further requires that all electricity provided to California, including imported electricity, must be generated from plants that meet the standards set by the PUC and CEC.

Executive Order S-1-07 (2007): Governor Schwarzenegger signed Executive Order S-1-07 in 2007 which finds that the transportation sector is the main source of GHG emissions in California. The executive order proclaims the transportation sector accounts for over 40 percent of statewide GHG emissions. The executive order also establishes a goal to reduce the carbon intensity of transportation fuels sold in California by a minimum of 10 percent by 2020.

In particular, the executive order established a Low-Carbon Fuel Standard (LCFS) and directed the Secretary for Environmental Protection to coordinate the actions of the CEC, CARB, University of California, and other agencies to develop and propose protocols for measuring the "life-cycle carbon intensity" of transportation fuels. This analysis supporting development of the protocols was included in the State Implementation Plan for alternative fuels (State Alternative Fuels Plan adopted by CEC on December 24, 2007) and was submitted to CARB for consideration as an "early action" item under AB 32. CARB adopted the LCFS on April 23, 2009.

Senate Bill 375 (2008): SB 375, signed in September 2008, aligns regional transportation planning efforts, regional GHG reduction targets, and land use and housing allocation. SB 375 requires Metropolitan Planning Organizations (MPOs) to adopt a Sustainable Communities Strategy (SCS) or Alternative Planning Strategy (APS) which prescribes land use allocation in that MPO's Regional Transportation Plan (RTP). CARB, in consultation with MPOs, is required to provide each affected region with reduction targets for GHGs emitted by passenger cars and light trucks in the region for the years 2020 and 2035. These reduction targets will be updated every eight years but can be updated every four years if advancements in emissions technologies affect the reduction strategies to achieve the targets. CARB is also charged with reviewing each MPO's SCS or APS for consistency with its assigned GHG emission reduction targets. CARB set the following reduction targets for ABAG/MTC region: reduce per capita seven percent of GHG emissions below 2005 levels by 2020 and 15 percent below 2005 levels by 2035.

Executive Order S-13-08 (2008): Governor Schwarzenegger signed Executive Order S-13-08 on November 14, 2008 which directs California to develop methods for adapting to climate change through preparation of a statewide plan. The executive order directs OPR, in cooperation with the Resources Agency, to provide land use planning guidance related to sea level rise and other climate change impacts.

Senate Bills 1078 and 107 and Executive Order S-14-08 (2008): SB 1078 (Chapter 516, Statutes of 2002) requires retail sellers of electricity, including investor owned utilities and community choice aggregators, to provide at least 20 percent of their supply from renewable sources by 2017. SB 107 (Chapter 464, Statutes of 2006) changed the target date to 2010. In November 2008, then Governor Schwarzenegger signed Executive Order S-14-08, which expands the state's Renewable Portfolio Standard to 33 percent renewable power by 2020.

SB X-1-2 and the Clean Energy and Pollution Reduction Act of 2015: SB X-1-2, signed by Governor Edmund G. Brown, Jr. in April 2011, created a new Renewables Portfolio Standard (RPS), which preempted CARB's 33 percent Renewable Electricity Standard. The new RPS applies to all electricity retailers in the state including publicly owned utilities (POUs), investor-owned utilities, electricity service providers, and community choice aggregators. These entities must adopt the new RPS goals of 20 percent of retail sales from renewables by the end of 2013, 25 percent by the end of 2016, and the 33 percent requirements by the end of 2020.

Clean Energy and Pollution Reduction Act of 2015, SB 350 (Chapter 547, Statutes of 2015) was approved by Governor Brown on October 7, 2015. SB 350 will: (1) increase the standards of the California RPS program by requiring that the amount of electricity generated and sold to retail customers per year from eligible renewable energy resources be increased to 50 percent by December 31, 2030; (2) require the State Energy Resources Conservation and Development Commission to establish annual targets for statewide energy efficiency savings and demand reduction that will achieve a cumulative doubling of statewide energy efficiency savings in electricity and natural gas final end uses of retail customers by January 1, 2030; (3) provide for the evolution of the Independent System Operator (ISO) into a regional organization; and (4) require the state to reimburse local agencies and school districts for certain costs mandated by the state through procedures established by statutory provisions. Among other objectives, the Legislature intends to double the energy efficiency savings in electricity and natural gas final end uses of retail customers through energy efficiency and conservation.

SB 862: In June 2014, SB 862 (Chapter 36, Statutes of 2014) established long-term funding programs from the Cap and Trade program for transit, sustainable communities and affordable housing, and high speed rail. SB 862 allocates 60 percent of ongoing Cap and Trade revenues, beginning in 2015–2016, to these programs. The remaining 40 percent is to be determined by future legislatures. A minimum of 25 percent of Cap and Trade dollars must go to projects that provide benefits to disadvantaged communities, and a minimum of 10 percent must go to projects located within those disadvantaged communities. In addition, this bill established the CalRecycle Greenhouse Gas Reduction Revolving Loan Program and Fund.

Senate Bills 32 and 350 and Executive Order B-30-15 (2015): Governor Brown signed Executive Order B-30-15 in 2015 in order to reduce GHG emissions by 40 percent below 1990 levels by 2030 to ensure California meets its target of reducing GHG emissions to 80 percent of 1990 levels by 2050. In particular, the Executive Order commissioned CARB to update the Climate Change Scoping Plan and the California Natural Resources Agency to update the state climate adaption strategy, Safeguarding California, every three years. The Safeguarding California Plan will identify vulnerabilities to climate change by sector and regions, including, at a minimum, the following sectors: water, energy, transportation, public health, agriculture, emergency services, forestry, biodiversity and habitat, and ocean and coastal resources; outline primary risks to residents, property, communities and natural systems from these vulnerabilities, and identify priority actions needed to reduce these risks; and identify a lead agency or group of agencies to lead adaptation efforts in each sector.

Assembly Bill 197: State Air Resources Board: Greenhouse Gases: AB 197 provides additional direction to CARB on the following areas related to the adoption of strategies to reduce GHG emissions. Additional direction in AB 197 meant to provide easier public access to air emissions data that are collected by CARB was posted in December 2016. AB 197 requires annual posting of GHG, criteria, and toxic air contaminant data throughout the State, organized by local and sub-county level for stationary sources and by at least a county level for mobile sources. AB197 also requires that when adopting rules and regulations to achieve emissions reductions to protect the State's most affected and disadvantaged communities, CARB shall consider the social costs of the emissions of GHGs, and prioritize emission reduction rules and regulations that result in direct emission reductions at large stationary sources of GHG emissions and direct emission reductions from mobile sources.

3.3.3.3 Local Regulations

The Air District established a climate protection program in 2005 to explicitly acknowledge the link between climate change and air quality. In November 2013, the Air District's Board of Directors adopted a resolution outlining greenhouse gas reduction goals of achieving an 80 percent reduction in GHG below 1990 levels and making a commitment to develop a regional climate protection strategy. The Air District regularly prepares inventories of GHG, criteria pollutants and toxic air contaminants to support planning, regulatory and other programs.

The District adopted a 10-point Climate Action Work Program in March 2014. The work program outlines the District's priorities in reducing GHG emissions that include: (1) establishing the goal of reducing GHG emissions 80 percent below 1990 levels by 2050; (2) updating the District's regional GHG emission inventory; (2) implementing GHG emissions monitoring; (4) developing a regional climate action strategy to meet the 2050 GHG emission reduction goal; (5) supporting and enhancing local actions through enhanced technical assistance to local governments in preparing local Climate Action Plans; (6) initiating rule development to enhance GHG reductions from sources subject to Air District regulations; (7) expanding enforcement of statewide regulations to reduce GHG emissions; (8) launching climate change and public health impacts initiative; (9) reporting progress to the public toward the 2050 goals and related performance objectives; and (10) exploring the Bay Area's energy future, including trends in fossil fuel demand and productions and exploring opportunities to promote the development of clean energy options.

In 2015, the Air District launched a GHG measurement program to provide the scientific basis that supports rulemaking and policy development for reducing GHG emissions. The program started monitoring GHGs in 2016 and includes a long-term fixed-site GHG monitoring network that measures concentrations of carbon dioxide, methane, and carbon monoxide at four sites. A dedicated mobile GHG monitoring research van also provides assistance in identifying emission hot spots and enhancing the regional emissions inventory.

Finally, the recently release 2017 Air Plan identifies control measures that include potential rules, programs, and strategies that the Air District can pursue to reduce GHG emissions in the Bay Area in support of the goals of reducing GHG emissions to 90 percent below 1990 levels by 2050.

3.3.3 THRESHOLDS OF SIGNIFICANCE

The most recently available BAAQMD draft CEQA guidelines established GHG thresholds for specific projects, general plans, and regional plans. An air quality rule does not fall neatly into any of these categories. Air Quality rules are typically regional in nature, as opposed to general plans, community plans and regional plans. In addition, air quality rules are usually specific to particular source types and particular pollutants.

The Air Quality Plan threshold of “no net increase in emissions” is appropriate for Air Quality Plans because they include a mix of several control measures with individual trade-offs. For example, one control measure may result in combustion of methane to reduce greenhouse gas emissions, while increasing criteria pollutant emissions by a small amount. Those increases from the methane measure would be offset by decreases from other measures focused on reducing criteria pollutants. In a particular rule development effort, there may not be opportunities to make these trade-offs.

The project level GHG threshold for stationary source projects is 10,000 metric tons of carbon dioxide equivalent (CO_2eq) emissions. This threshold is expected to capture approximately 95 percent of all GHG emissions from new permit applications from stationary sources within the jurisdiction of the Air District. The threshold level was calculated as an average of the combined CO_2 emissions from all stationary source permit applications submitted to the Air District during the three year analysis period (BAAQMD, 2010). The Air District is planning to develop significance thresholds specifically for rules. Until that effort is complete, the project-level GHG significance thresholds of 10,000 MT CO_2eq will be used to evaluate the cumulative GHG impact of each rule.

3.3.4 GHG EMISSION IMPACTS

GHG emissions impacts occur as a result of increased accumulation of GHGs in the atmosphere that may result in global climate change. Due to the complexity of conditions and interactions affecting global climate change, it is not possible to predict the specific impact, if any, attributable to GHG emissions associated with a single project. Although the geographic scope of this GHG emissions impact analysis in this EIR is the State of California, it is the cumulative effects of all global GHG emissions sources that have the potential result in global climate change. For this reason, GHG emission impacts contributing to global climate change are considered a cumulative impact analysis rather than a project-specific analysis.

With regard to potential GHG emission impacts, most GHG emissions sources at facilities that would be regulated by ~~either Rule 11-18 or~~ Rule 12-16 would include equipment or processes, primarily combustion sources that are part of the facilities’ operations. Though the proposed project may include combustion processes that could generate GHG emissions such as CO_2, CH_4, and N_2O, the proposed project does not affect equipment or operations that have the potential to emit other GHGs such as sulfur hexafluoride (SF6), hydrofluorocarbon (HFC) or perfluorocarbon (PFC). GHGs could be emitted during construction activities to install air pollution control equipment from sources such as off-road construction equipment, which could be comprised of off-road mobile sources, e.g., bull dozers, cranes, forklifts, etc. GHGs could also be emitted during construction from on-road mobile sources such as haul trucks delivering products used in the pollution control process and construction worker commute trips. During operation GHG emission impacts could occur from air pollution control equipment that uses combustion as part of the control process. GHG emissions from existing facilities subject to Rule 12-16 are part of the existing setting. Further, operational sources of GHG emissions are subject to the GHG emission reductions on the AB 32 Cap and Trade program. Therefore, existing sources of GHG emissions are not included as part of the GHG impacts analyzed in the following sections.

3.3.4.1 Potential GHG Emission Impacts During Construction

GHG emissions sources during construction to install air pollution control equipment would generally be the same types of sources as described in the construction criteria pollutant emission sources discussion in Section 3.2.4.1. Similar to the construction air quality impacts in Section 3.2.4.1, the analysis of potential GHG construction air quality impacts focuses on those types of air pollution control equipment that would produce the greatest construction emissions. Construction activities and equipment to install most other types of air pollution control equipment would tend to be substantially less than those identified in the following subsections.

Construction activities associated with installing air pollution control technologies would result in GHG emissions, although the amount generated by specific types of equipment can vary greatly as shown in Table 3.3-5. The estimated GHG emissions for construction equipment operating on a typical eight-hour day are also provided in Table 3.3-5.

Discussions of GHG emission impacts described in the following subsections generally follow the format of construction emission impacts in Section 3.2.4.1, that is, by type of control technology. The following analyses of potential GHG use the same construction assumptions and scenarios.

TABLE 3.3-5

GHG Emission Estimates for Typical Construction Equipment Assuming an 8-Hour Operational Day (1)

Equipment Type	CO_2e (MT/hr)	CO_2e (MT/8-hr day)
Aerial Lifts- (Man Lifts)	0.01	0.09
Air Compressor	0.02	0.16
Bore/Drill Rigs	0.06	0.47
Concrete Pump	0.003	0.02
Concrete Saw	0.02	0.16
Crane	0.04	0.028
Excavator	0.03	0.26
Forklift	0.01	0.08
Generator	0.02	0.16
Grader	0.04	0.33
Pavers	0.03	0.23
Paving Equipment	0.02	0.2
Rollers	0.02	0.13
Rough Terrain Forklifts	0.02	0.17
Rubber Tired Dozers	0.05	0.42
Rubber Tired Loaders	0.04	0.31
Scrapers	0.09	0.75
Skid Steer Loaders	0.01	0.10
Surfacing Equipment	0.04	0.34
Tractors/Loaders/Backhoes	0.02	0.15
Trenchers	0.02	0.17
Welders	0.01	0.08

(1) Emission Factors from Off-Road 2011

3.3.4.1.1 Diesel ICEs ~~– Both Rules~~

As indicated in Section 3.2.4.1.1, the refineries ~~most facilities that would be~~ subject to ~~either Rule 11-18 or~~ Rule 12-16 have diesel ICEs that are used as a backup source of electricity in the event of a power outage or ~~for refineries,~~ as a means of pumping liquids between different refinery equipment. Operators generally have two options for reducing diesel ICE emissions, replacing a Tier 1 ICE with a new Tier 4 ICE or retrofitting the existing diesel ICE with a DPF or DOC. Table 3.3-6 estimates GHG emissions from replacing Tier 1 ICEs with Tier 4 ICEs and Table 3.3-7 estimates GHG emissions from retrofitting diesel ICEs with DPFs or DOCs.

TABLE 3.3-6

GHG Emissions During Construction Associated with Replacing ICEs

Activity	CO_2e MT/day (1)
Sub-total Off-road Construction Equipment	0.14
Sub-total On-road (Worker + Haul Truck) (2)	0.23
Total - 1 ICE Replacement	0.37
~~Rule 11-18 - 10 Replacements~~	~~3.7~~
Rule 12-16 - 5 Replacements	1.9
~~Both Rules - 15 Replacements~~	~~5.6~~

(1) Results are in metric tons per day because construction is assumed to last one day.

(2) See Appendix B for calculation details. Haul trucks are heavy heavy-duty diesel trucks.

TABLE 3.3-7

GHG Emissions During Construction Associated with Retrofitting ICEs (1)

Activity	CO_2e MT/day (2)
Sub-total Off-road Construction Equipment	1.81E-05
Sub-total On-road (Worker + Haul Truck) (2)	0.22
Total - 1 ICE Retrofit	0.22
~~Rule 11-18 - 10 Retrofit~~	~~2.3~~
Rule 12-16 - 5 Retrofit	1.1
~~Both Rules - 15 Retrofit~~	~~3.4~~

(1) See Appendix B for calculation details.

(2) Results are in metric tons per day because construction is assumed to last one day. Haul trucks are heavy heavy-duty diesel trucks.

3.3.4.1.2 Installing a Wet Gas Scrubber ~~- Both Rules~~

As described in Section 3.2.4.1 construction GHG emissions to install a WGS, one of the largest types of air pollution control equipment that could be installed to comply with ~~either Rule 11-18 or~~ Rule 12-16, would occur over an 18-month period; one month to demolish any nearby existing equipment or structures and 17 months to construct the WGS. Demolition activities were assumed to require a construction crew of 50 workers and the use of one or more of the following types of equipment: crane, front-end loader, forklift, demolition hammer, water truck, medium-duty flatbed truck, etc. Constructing a WGS was assumed to require a construction crew of 175 workers and the use of one or more of the following types of construction equipment: backhoes, cranes, man lifts, forklift, front end loaders generators, diesel welding machines, jack hammers, a medium-duty flatbed truck, a medium-duty dump truck, a cement mixer, etc. GHG emissions from installing a WGS are shown in Table 3.3-8.

TABLE 3.3-8

GHG Emissions from Installing Wet Gas Scrubbers onto an FCCUs

Activity	CO2e MT (1)
Construction Activities for 1 WGS	~~468~~ 448
Construction Emissions for 3WGS on Refinery Units	~~1,404~~ 1,345
Construction Emissions for 5 WGS on Refinery Units	~~2,340~~ 2,241

Source: BAAQMD, 2017

(1) MT values include construction and demolition emissions and are based on emissions during the entire construction period.

3.3.4.1.3 Installing a Selective Catalytic Reduction Unit ~~– Rule 12-16 Only~~

The analysis of construction GHG emissions to install an SCR unit is included here because it would apply ~~only~~ to Rule 12-16 and is typically a large unit that would require substantial construction activities. SCR is typically considered to be BACT or BARCT to reduce NO_x emissions from large industrial combustion sources. Combustion sources at affected facilities that could be retrofitted with SCR include refinery FCCUs, boilers, process heaters, or gas turbines. However, such units are typically smaller compared to retrofitting an SCR onto an FCCU, so construction crews would be smaller and the overall duration of construction activities would be much shorter. Because retrofitting an SCR onto an FCCU would provide a more conservative analysis of construction air quality impacts than retrofitting an SCR onto refinery boilers, process heaters, or gas turbines, the following analysis focuses on quantifying construction emissions from installing an SCR onto an FCCU. The GHG construction emissions analysis uses the same construction assumptions and construction scenarios that were used in Section 3.2.4.1. GHG emissions from installing an SCR onto an FCCU are shown in Table 3.3-9

TABLE 3.3-9

GHG Emissions from Installing Selective Catalytic Reduction Units onto an FCCU (1)

Activity	CO_2e MT (2)
Sub-total Off-road Construction Equipment	~~195~~ 289
Sub-total On-road (Worker + Haul Truck) (3)	379
Construction Emissions for 1 SCR on an FCCU	~~574~~ 668
Construction Emissions for 3 SCRs on an FCCU	~~1,722~~ 2,003

(1) See Appendix B for calculation details.

(2) MT values include construction and demolition emissions and are based on emissions during the entire construction period.

(3) Haul trucks are heavy heavy-duty diesel trucks.

~~3.3.4.1.4 Installing a Carbon Adsorption Unit – Rule 11-18 Only~~

~~As indicated in Section 3.2.4.1, the most likely TAC emission sources that would be subject to Rule 11-18 and that could be controlled using carbon adsorption units are expected to be sewage treatment facilities because various stages of the sewage treatment process produce ROG emissions that may include TAC components. The GHG construction air quality analysis for installing a carbon adsorption unit is based on a construction emissions analysis from installing air pollution control equipment similar in size to a carbon adsorption unit because no actual carbon adsorption construction scenarios were identified. Construction assumptions and parameters associated with installing a carbon adsorption unit are the same as those used in Subsection 3.2.4.1.4. Table 3.3-10 shows the expected construction GHG emissions from installing carbon adsorption units.~~

~~TABLE 3.3-10~~

~~GHG Emissions During Construction of Carbon Adsorption Units~~ ~~(1)~~

~~Activity~~	~~CO_2e MT~~ ~~(2)~~
~~Sub-total Off-road Construction Equipment~~	~~72~~
~~Sub-total On-road (Worker + (3))~~	~~72~~
~~Construction Emissions for 1 Carbon Adsorption Unit~~	~~148~~
~~Construction Emissions for 5 Carbon Adsorption Unit~~	~~742~~

~~(1) See Appendix B for calculation details.~~

~~(2) MT values include construction and demolition emissions and are based on emissions during the entire construction period.~~

~~(3) Haul trucks are heavy heavy-duty diesel trucks.~~

3.3.4.1.5 Summary of Construction Emission Impacts

As demonstrated in the subsections above, construction and installation of some types of air pollution control technologies would not necessarily be expected to result in substantial GHG air quality impacts during construction. For example, replacing existing diesel ICEs with Tier 4 ICEs or retrofitting diesel ICEs with DPFs of DOCs could occur if ~~either Rule 11-18 or~~ Rule 12-16 is adopted. For either control scenario, GHG emissions would be relatively low and would only be expected to occur on a single day. ~~As shown in Tables 3.3-6 and 3.3-7, GHG air quality impacts during construction from installing new, or retrofitting existing diesel ICEs would be greater under Rule 11-18 than under Rule 12-16 because substantially more industrial facilities that have diesel ICEs would be regulated under Rule 11-18. GHG air quality impacts during construction would be greater still if more than one diesel ICE is replaced or retrofitted on the same day or both rules are adopted.~~

Demolition and construction GHG emissions impacts from installing a single large-scale air pollution control unit, a single WGS for example, which could take up to 18 months to complete demolition and construction, is one type of air pollution control equipment that has the potential to produce substantial construction GHG emissions. Construction activities for smaller types of air pollution control equipment such as ~~carbon adsorption units that may be installed under Rule 11-18 or~~ SCRs that may be installed under Rule 12-16, would have lower GHG emissions, but they could still be substantial, especially if more than unit is installed at the same time.

As summarized in Table 3.2-~~11~~10, construction activities under Rule 12-16~~, respectively,~~ could produce GHG air quality impacts during construction if larger types of air pollution control equipment are installed. These potential GHG emission impacts would be compounded if more than one piece of air pollution control equipment is installed on the same day. ~~Again, because Rule 11-18 would potentially regulate a substantially greater number of industrial sources, it would create greater GHG air quality impacts during construction than Rule 12-16.~~

TABLE 3.3-~~11~~10

Worst-Case Construction GHG Emissions Under Rule 12-16 ~~Both Rules~~

Activity	CO_2e MT
~~Peak Construction GHG Emissions Under Rule 11-18~~	
~~Total Construction Emissions for 10 Diesel ICE Replacement~~	~~3.7~~
~~Total Construction Emissions for 10 Diesel ICE Retrofit~~	~~2.3~~
~~Total Construction Emissions for 5 WGS~~	~~2,340~~
~~Total Construction Emissions for 5 Carbon Adsorption~~	~~742~~
~~Total Potential Overlapping GHG Emissions~~	~~3,088~~
~~Total Potential Overlapping GHG Emissions (Amortized)(1)~~	~~103~~
Peak Construction GHG Emissions Under Rule 12-16	
Total Construction Emissions for 5 Diesel ICE Replacement	1.9
Total Construction Emissions for 5 Diesel ICE Retrofit	1.1
Total Construction Emissions for 5 WGS	~~2,340~~ 2,241
Construction Emissions for 3 SCRs on an FCCU	~~1,722~~ 2,003
Total Potential Overlapping GHG Emissions	~~4,065~~ 4,247
Total Potential Overlapping GHG Emissions (Amortized)(1)	~~136~~ 142

(1) Amortized over 30 years. MT/yr

The Air District does not have an adopted threshold of significance for construction-related GHG emissions. However, since GHG emissions are cumulative and construction emission are short-lived, the total construction GHG emissions are amortized over 30 years to create an annual emission rate that is combined with the operational GHG emissions for determining significance. The operational GHG emission analysis and significance determination are presented in the following sections.

3.3.4.2 Potential GHG Emission Impacts During Operation

The analysis of operational GHG emission impacts from the proposed project would include direct GHG emissions from air pollution control equipment and indirect emissions, e.g., haul truck emissions from transporting fresh supplies of caustic. Table 3.3-~~12~~11 shows air pollution control technologies that would be the most likely technologies installed at affected facilities to reduce ~~TAC emissions under Rule 11-18 and~~ GHG, NOx, SO_2, PM_{10}, and PM2.5 emissions under Rule 12-16 and that may have the potential to generate direct or indirect GHG emission impacts during operation. The subsections below evaluate those air pollution control technologies identified in Table 3.3-~~12~~11 that have the potential to generate adverse direct or indirect operational GHG emission impacts. Air pollution control technologies where no direct or indirect operational GHG emission impacts were identified will not be discussed further.

TABLE 3.3-~~12~~11

Potential Operational GHG Impacts from Installing Air Pollution Control Equipment

Applicable Rule	Potential Control Technology	GHG Impacts	Analyzed Further?
~~11-18 &~~ 12-16	Baghouse with HEPA Filters	None identified	**No**
~~11-18~~	~~Carbon Adsorption~~	~~Combustion emissions from regenerating spent carbon~~	~~**Yes**~~
12-16	Compressor	None identified	**No**
12-16	Cyclone	None identified	**No**
~~11-18 &~~ 12-16	Diesel Oxidation Catalyst	None identified	**No**
~~11-18 &~~ 12-16	Diesel Particulate Filter	None identified	**No**
12-16	Electrostatic Precipitator (Wet and Dry)	None identified	**No**
12-16	Fuel Gas Treatment (Additive to Existing Amine System)	None identified	**No**
12-16	Fuel Gas Treatment (Merox)	None identified	**No**
12-16	LoTOx™	None identified	**No**
~~11-18 &~~ 12-16	New Diesel ICEs	None identified	**No**
12-16	Selective Catalytic Reduction	Indirect mobile source emission increases	**Yes**
12-16	Selective Oxidation Catalyst	None identified	**No**
~~11-18~~	~~Steam Ejector Technology~~	~~None identified~~	~~**No**~~
12-16	SOx Reducing Additive	None identified	**No**
~~11-18~~	~~Thermal Oxidizer~~	~~Potential increase in combustion emissions~~	~~**Yes**~~
12-16	Ultracat	Indirect mobile source emission increases	**Yes**
~~11-18 &~~ 12-16	Wet Gas Scrubber	Indirect mobile source emission increases. Increased electricity.	**Yes**

~~3.3.4.2.1 GHG Emissions from Regenerating Spent Carbon (Rule 11-18 Only)~~

~~As indicated in Table 3.3-12, a carbon adsorption unit is one type of control technology that has the potential to generate GHG emissions. Chapter 3, Subsection 3.2.4.2.1 describes the operation of carbon adsorption units and notes that, once the bed of activated carbon becomes saturated, it is typically regenerated by raising the temperature of the carbon, evacuating the bed, or both. Regenerating spent carbon typically requires a combustion source using natural gas as the combustion fuel to heat the regenerant and/or to heat the carbon beds. This process of regenerating spent carbon is the point where GHG emissions would be generated.~~

~~The assumptions used to calculate criteria pollutant emissions from carbon adsorption units are used in this analysis. Carbon adsorption units are regenerated four times per day and 0.062 scfm/day of natural gas is used as the combustion fuel. Table 3.3-13 shows annual GHG emission impacts from regenerating spent carbon.~~

~~TABLE 3.3-13~~

~~Annual GHG Emissions from Carbon Adsorption Units~~

	~~Metric Tons/Year~~			
~~Number of Units~~	~~CH_4~~	~~N_2O~~	~~CO_2~~	~~CO_2e~~
~~1 Unit~~	~~0.02~~	~~0.01~~	~~1,231.56~~	~~1,234~~
~~5 Units~~	~~0.12~~	~~0.03~~	~~6157.82~~	~~6,172~~

~~CO_2, N_2O and CH_4 emission factors from AP-42 Table 1.4-2, July 1998~~

~~3.3.4.2.2 GHG Emissions from Thermal Oxidizers (Rule 11-18 Only)~~

~~As indicated in Chapter 3.2, Subsection 3.2.4.2.3, it is expected that thermal oxidizers would be used to control TAC emissions primarily at landfills and sewage treatment facilities. As part of its CEQA evaluation of BAAQMD Regulation 2, Rule 5, the Air District prepared an Initial Study/Negative Declaration (BAAQMD, 2016a). That CEQA document also identified thermal oxidizers as a potential air pollution control device that could be used to reduce TAC emissions. The document also includes an analysis of potential GHG emission impacts from thermal oxidizers. That analysis concluded that operation of one thermal oxidizer has the potential to generate 910.1 metric tons of CO_2e per year. Since Rule 11-18 is also designed to reduce TAC emissions, the analysis of GHG emissions from thermal oxidizers in the Initial Study/Negative Declaration would be applicable to this analysis. Since it is assumed that up to five thermal oxidizers could be installed to comply with the risk reduction requirements in Rule 11-18, annual GHG emissions could be as much as 4,550.5 metric tons of CO_2e per year.~~

~~3.3.4.2.3~~3.3.4.2.1 Indirect Mobile Source Emissions

Several types of air pollution control devices identified in Table 3.3-~~12~~11 use specific substances to assist with the emission reduction process. For example, SCR promotes chemical reactions in the presence of a catalyst. As a result, SCRs would require delivery of ammonia or urea to the facilities where they are installed. It is estimated that about 40 truck trips per year would be required for the delivery of ammonia/urea to each facility with an SCR. This amount could vary depending on the size of the SCR and size of the ammonia or urea storage systems. However, 40 trucks per year per facility is assumed to provide a conservative estimate of transportation requirements.

Similar to SCRs, WGS units use NaOH as a caustic solution to reduce emissions. Catalyst and caustic solutions are typically used in relatively small amounts per day. Indirect emission impacts could also occur from haul trucks associated with delivering supplies (i.e., fresh catalyst and caustic solution to refill the storage tanks) on a regular basis. Depending on the size and configuration of the WGS, the NaOH caustic solution used in the WGS would likely need to be delivered one time per week or a little over 50 additional delivery truck trips per year.

Haul truck trips transporting ammonia or NaOH caustic would occur relatively infrequently and it is not likely that all affected facilities would transport materials on the same day. However, GHG emissions are quantified on an annual basis so all truck trips would contribute to GHG emission impacts. GHG emission impacts from truck transport trips carrying materials for SCRs and WGS units are shown in Table 3.3-~~14~~12.

TABLE 3.3-~~14~~12

Annual GHG Emissions from Delivery Truck Trips

Material	Number of Truck Trips	Trip Length (Roundtrip miles	CO2e
Peak Operational Emissions One Facility (Metric Tons/Day)			
Caustic/Catalyst for WGS Unit	~~2~~ 10	120	~~0.23~~ 2.3
Ammonia for SCR	~~2~~ 6	100	~~0.20~~ 1.2
Total			~~0.43~~ 3.5
Peak Operational Emissions One Facility (Metric Tons/year)			
Caustic/Catalyst for WGS Unit	104	120	24
Ammonia for SCR	80	100	16
Total			40
Peak Operational Emissions Multiple Facilities (Metric Tons/year)			
Caustic/Catalyst for WGS 5 Units	520	120	121
Ammonia for SCR 3 Units	240	100	47
Total			168

Source: BAAQMD, 2017

~~3.3.4.2.4~~3.3.4.2.2 Indirect Emissions from Electricity Generation

Electricity is often used as the power source to operate various components of add-on control equipment, such as ventilation systems, fan motors, vapor recovery systems, etc. Increased demand for electrical energy may require generation of additional electricity, which in turn could result in increased GHG emissions in the Bay Area and in other portions of California. For example, installing WGS may increase pressure drop in the flue gas system. Similarly, installing an SCR may also increase pressure drop in the flue gas system. Additional power may be needed to compensate for this additional pressure drop.

The production of electricity to operate the WGS units or SCRs would generate GHG emissions. The estimated GHG emission increase associated with increased electricity use for WGS units and SCRs is shown in Table 3.3-~~15~~13.

TABLE 3.3-~~15~~13

GHG Emissions Associated with Electricity from Air Pollution Control Equipment ~~Electricity Use at Wet Gas Scrubbers~~

Control Equipment	Number of Units	Potential Increased Electricity Demand (MWhr/yr	Emission Factor (lb/MWhr) (1)	Emissions ($CO2_e$ MT/yr)
WGS	5	1,305	644	381
SCR	3	665.7	644	194
Maximum Total				575

Source: BAAQMD, 2017
(1) CAPCOA, 2016. Based on PG&E emission factors from CalEEMod.

3.3.4.2.3 Summary of Operational GHG Emissions

Based on the evaluation of those air pollution control technologies that would most likely be the used to reduce NOx, SO_2, and PM2.5~~, and TAC~~ emissions from affected facilities if required pursuant to ~~Rule 11-18 or~~ Rule 12-16, ~~respectively,~~ potential operational GHG impacts from the proposed project could occur, driven primarily by installation of WGS units. ~~and carbon adsorption units.~~ Some indirect mobile sources from delivering materials necessary for the pollution control process would also occur. ~~under both rules.~~ Table 3.3-~~16~~14 summarizes the GHG emission impacts. ~~for each rule.~~

CARB's Cap and Trade program was designed to reduce GHG emissions from major sources (covered entities) by setting a firm cap on statewide GHG emissions while employing market mechanisms to cost-effectively achieve the GHG emission-reduction goals. The Cap and Trade program relies on data collected through the Mandatory Reporting of Greenhouse Gas Emissions Regulation (MRR) and required affected facilities to report their annual GHG emissions in 2009 and every year thereafter. Further, under the Cap and Trade program, individual facilities do not receive individual facility-wide caps, but industrial sectors receive allowances. The sectors include electricity, transportation fuels, oil and gas processing, and other general industrial facilities. Since, there is no specific information as to where control equipment would be required, it would be speculative to assume that GHG emissions would be offset under AB 32 Cap and Trade.

TABLE 3.3-~~16~~14

Worst-Case Operational GHG Emissions Under ~~Both~~ Rule 12-16

Activity	CO_2e MT/Year
~~Peak Operational GHG Emissions Under Rule 11-18~~	
~~Total Amortized Construction Emissions~~	~~103~~
~~Total Operational Emissions for 5 Carbon Adsorption Units~~	~~6,172~~
~~Total Operational Emissions 5 Thermal Oxidizers~~	~~4,551~~
~~Total Haul Truck Emissions for 5 WGS Units~~	~~121~~
~~Total Electrical Emissions for 5 WGS Units~~	~~381~~
~~Total Potential Overlapping GHG Emissions~~	~~11,328~~
~~Significance Threshold~~	~~10,000 MT/yr~~
~~Significant?~~	**~~Yes~~**
Peak Operational GHG Emissions Under Rule 12-16	
Total Amortized Construction Emissions	~~136~~ 142
Total Haul Truck Emissions for 5 WGS Units	121
Total Haul Truck Emissions for 3 SCRs	47
Total Electrical Emissions for 5 WGS Units	381
Total Electrical Emissions for 3 SCR Units	194
Total Potential Overlapping GHG Emissions	~~879~~ 885
Significance Threshold	10,000 MT/yr
Significant?	No

3.3.4.3 Potential Conflicts With State GHG Compliance Plans

The NOP/IS for the proposed project noted that CARB's Cap and Trade program allows covered facilities to buy and sell GHG emissions credits, while Rule 12-16 would not allow Bay Area refineries to purchase GHG credits to demonstrate compliance with the refinery-wide GHG limit. As a result, Rule 12-16 has the potential to conflict with CARB's Cap and Trade program, which was adopted for the purpose of reducing GHG emissions throughout California.

As explained above, CARB's Cap and Trade program was designed to reduce GHG emissions from major sources (covered entities) by setting a firm cap on statewide GHG emissions while employing market mechanisms to cost-effectively achieve the GHG emission-reduction goals. The Cap and Trade program relies on data collected through the Mandatory Reporting of Greenhouse Gas Emissions Regulation (MRR) and required affected facilities to report their annual GHG emissions in 2009 and every year thereafter. Further, under the Cap and Trade program, individual facilities do not receive individual facility-wide caps, but industrial sectors receive allowances (see next paragraph regarding allowances). The statewide cap for GHG emissions from major sources, which is measured in metric tons of carbon dioxide equivalent (MTCO2e), commenced in 2013 and has declined over time, achieving GHG emission reductions throughout the program's duration. The statewide cap for GHG emissions from major sources commenced in 2013 at about two percent below the emissions level forecast for 2012, it declined about two percent in 2014, and then declines about three percent annually from 2015 to 2020, thus, achieving GHG emission reductions throughout the program's duration.

Proposed Rule 12-16 would establish GHG emission limits on refineries and refinery-dependent businesses in the Bay Area. Based on annual GHG emissions for each affected facility from the year 2012 through 2015, the latest year information is available, no facility exceeded its currently proposed Rule 12-16 GHG limits for any year in which data are available. However, these years also were years of relatively low gasoline consumption in California. Total gasoline consumption in the state peaked in 2004 and then declined 8.94 percent between 2004 and 2012, per data from the California Energy Commission. Gasoline consumption has been increasing every year since then. If gasoline consumption continues to increase, the limits in Rule 12-16 may prevent Bay Area refineries from increasing production to meet demand. This scenario could cause conflicts with GHG and perhaps result in increased GHG emissions outside the Bay Area due to the manufacture of transportation fuels being shifted elsewhere.

The data in Table 3.3-~~17~~15, indicate that Rule 12-16 would not be expected to conflict with CARB's Cap and Trade program because covered entities could continue to use GHG credits for compliance purposes. That data may not be predictive of future scenarios; however, it is the only data available at this time. Presuming continuing increases in gasoline consumption results in unreasonable levels of speculation. For example, it is impossible for the Air District to predict the exact level of gasoline consumption in 2018 and how that would relate to Bay Area refinery capacity and how the market might react if production at Bay Area refineries were constrained by Rule 12-16. Therefore, the Air District is assuming, based on historical data that potential GHG emission impacts under Rule 12-16 would not conflict with California's GHG compliance plan established under AB32 and these impacts are concluded to be less than significant.

TABLE 3.3-~~17~~15

Annual GHG Emission Inventories for Facilities Subject to Rule 12-16 (CO_2e in metric tons/year)

Facility	2012 GHG Inventory	2013 GHG Inventory	2014 GHG Inventory	2015 GHG Inventory	Proposed Rule 12-16 GHG Limit
Chevron Richmond	4,126,095	4,087,322	4,120,931	4,420,335	4,774,356.00
Shell Martinez	4,366,858	4,191,585	3,968,978	4,131,880	4,559,540.00
Phillips 66 San Francisco	1,320,965	1,363,918	1,276,578	1,320,782	1,607,925.00
Tesoro Martinez	2,089,720	2,445,615	2,334,466	2,056,107	2,615,047.00
Valero Benicia	2,939,902	2,738,051	2,710,549	2,839,357	3,145,008.00
Martinez Cogen LP	413,261	386,217	411,584	401,277	450,633.00
Air Liquide H2 Rodeo	770,858	884,931	815,746	819,886	946,876.00
Air Products H2 Martinez	217,135	270,753	255,203	196,728	289,706.00

3.3.4.4 Conclusion

Evaluation of those air pollution control technologies that would most likely be used to reduce ~~TAC,~~ NOx, SO_2, PM, and GHG emissions from affected facilities, if required pursuant to ~~Rule 11-18 or~~ Rule 12-16, ~~respectively,~~ indicates that ~~Rule 11-18 could generate direct and indirect GHG emission impacts that exceed the Air District's operational GHG emissions significance threshold of 10,000 MTCO2e/yr. However,~~ direct and indirect GHG emission impacts for Rule 12-16 are less than the Air District's GHG significance threshold and, therefore, are concluded to be less than significant. Therefore, because the analysis of GHG emission impacts is by definition a cumulative impact analysis, cumulative operational GHG emission impacts ~~for Rule 11-18 are concluded to be significant, but~~ are less than significant for Rule 12-16. ~~However, if both rules are adopted, cumulative GHG emission impacts would be greater than either rule alone and, therefore, would be significant.~~

3.3.5 MITIGATION MEASURES

Measures to mitigate operational GHG emission impacts typically rely on energy efficiency measures. Improving energy efficiency is equipment- and operation-specific, so each affected facility operator would have to perform a facility-wide evaluation to determine appropriate energy efficiency measures. Such an analysis is outside the scope of the environmental analysis for the proposed project. However, there are programs in California designed to reduce GHG emissions statewide. For example, CARB has designed a California Cap and Trade program that is enforceable and meets the requirements of AB 32. The program began on January 1, 2012, with an enforceable compliance obligation beginning with the 2013 GHG emissions inventory. The refineries are subject to the requirements of the AB32 Cap and Trade Program and have a GHG allocation based on current GHG emissions levels. The AB32 Cap and Trade Program has divided allocations into sectors and established a Refinery Sector allocation. Sectors that are subject to the Cap and Trade program include large industrial facilities emitting 25,000 $MTCO_2e$ in the following sectors: petroleum refining, petroleum and natural gas systems, hydrogen production iron and steel production, in-state electricity generators, etc.

Under the Cap and Trade program, individual facilities do not receive individual facility-wide caps, but industrial sectors receive allowances. An allowance is a tradable permit to emit one metric ton of a carbon dioxide equivalent GHG emissions. Allowances are distributed among facilities based on their complexity and energy efficiency. The more energy efficient a facility is, the greater the allocation it receives. For example, according to the operational GHG analysis above, the primary source of GHG emission impacts would be refineries. The refinery allowance process includes both on-site generated and third-party power. Further, the AB32 Cap and Trade Program requires that the refineries subject to the program (including all refineries in the Bay Area) to offset any GHG emissions in excess of the total allowance obtained through the program. As the emissions cap is gradually reduced over time, and as additional sources are brought under the cap to include the vast majority of GHG emissions in the State, the program will ensure that California remains on track to continually reduce GHG emissions and meet the 2020 limit. Operational GHG emission increases would be offset if they occurred at facilities that are included in the Cap and Trade Program. However, since there is no specific information as to where the air pollution control equipment would occur it would be speculative to assume that GHG emissions would be offset under the AB 32 Cap and Trade Program at this time. Nonetheless, ~~some or~~ all of the GHG emissions that may be generated to comply with Regulations ~~11-18 and~~ 12-16 would be offset under the Cap and Trade Program.

Cumulative GHG impacts were evaluated in the 2017 Clean Air Plan EIR (BAAQMD, 2017). The 2017 Clean Air Plan contains numerous control measures that the District intends to impose to improve overall air quality in the District. Control measures in the 2017 Clean Air Plan included Rule 12-16 as well as a number of other control measures to control emissions from refineries as well as other stationary sources. The 2017 Clean Air Plan is expected to result in overall GHG emission reductions (BAAQMD, 2017). As reported in the Final EIR for the 2017 Air Plan, an estimate 1,555,339 metric tons/year of GHG emission reductions are expected from implementation of the 2017 Plan providing beneficial GHG impacts (see Table 3.3-15 of the Final EIR, BAAQMD 2017). These emission reductions are expected to help the Bay Area meet its climate change goals. The proposed Rule 12-16 is not expected to result in a cumulatively considerable contribution to GHG emissions or climate change impacts. GHG emission reductions from the 2017 Plan are expected to far outweigh any potential secondary GHG emission increases associated with implementation of the control measures in the 2017 Plan (including Rule 12-16), providing a beneficial impact on climate change.

3.3.5.2 Remaining Operational Impacts

~~Since the GHG emissions reductions expected from implementing AB 32 are speculative, cumulative GHG emission impacts are expected to remain significant for: (1) implementing Rule 11-18 alone; and (2) implementing both Rules 11-18 and 12-16 together.~~ The project-specific and cumulative GHG emissions impacts are expected to be less than significant for implementing Rule 12-16. ~~alone.~~

CHAPTER 3

ENVIRONMENTAL SETTING, IMPACTS, MITIGATION MEASURES, AND CUMULATIVE IMPACTS

Introduction
Air Quality
Greenhouse Gases
Hazards and Hazardous Materials
Hydrology and Water Quality
Growth Inducing Impacts
Significant Environmental Effects Which Cannot be Avoided
Environmental Effects Not Found to be Significant

3.0 ENVIROMENTAL SETTING, IMPACTS, MITIGATION MEASURES AND CUMULATIVE IMPACTS

3.1 INTRODUCTION

This chapter of the EIR describes the existing environmental setting in the Bay Area, analyzes the potential environmental impacts of implementing Rule12-16 and recommends mitigation measures (when significant environmental impacts have been identified). The chapter provides this analysis for each of the environmental areas identified in the Initial Study (see Appendix A), which are:

- Air quality;
- Climate change and greenhouse gas emissions;
- Hazards and Hazardous Materials; and
- Hydrology and water quality.
- ~~Noise;~~
- ~~Transportation and traffic; and~~
- ~~Utilities and service systems.~~

Included for each impact category is a discussion of the: (1) Environmental Setting; (2) Regulatory Setting; (3) Significance Criteria; (4) Environmental Impacts; (5) Mitigation Measures (if necessary and available); and (6) Cumulative Impacts. A description of each subsection follows.

3.1.1 ENVIRONMENTAL SETTING

CEQA Guidelines §15360 (Public Resources Code Section 21060.5) defines "environment" as "the physical conditions that exist within the area which will be affected by a proposed project including land, air, water, minerals, flora, fauna, ambient noise, and objects of historical or aesthetic significance." CEQA Guidelines §15125(a) requires that an EIR 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 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 description of the environmental setting is intended to be no longer than is necessary to gain an understanding of the significant effects of the proposed project and its alternatives.

This Chapter describes the existing environment in the Bay Area as it exists at the time the NOP/IS was prepared (October 2016) to the extent that information is available. The analyses included in this chapter focus on those aspects of the environmental resource areas that could be adversely affected by the implementation of the proposed revisions to District permitting regulations as determined in the NOP/IS (see Appendix A), and not those environmental resource areas determined to have no potential adverse impact from the proposed project. The NOP/IS (see Appendix A) determined the air quality, greenhouse gases, hazards and hazardous materials, and hydrology and water quality impacts associated with the proposed amendments were potentially significant and are evaluated in this EIR.

3.1.2 SIGNIFICANCE CRITERIA

This section identifies the criteria used to determine when physical changes to the environment created as a result of the proposed project approval would be considered significant. The levels of significance for each environmental resource were established by identifying significance criteria. These criteria are based upon those presented in the California Environmental Quality Act (CEQA) environmental checklist and the BAAQMD's CEQA Air Quality Handbook (BAAQMD, 1999 and 2011).

The significance determination under each impact analysis is made by comparing the proposed project impacts with the conditions in the environmental setting and comparing the difference to the significance criteria.

3.1.3 ENVIRONMENTAL IMPACTS

The CEQA Guidelines also require the EIR to identify significant environmental effects that may result from a proposed project (CEQA Guidelines §15126.2(a)). Direct and indirect significant effects of a project on the environment must be identified and described, with consideration given to both short- and long-term impacts. The potential impacts associated with each resource are either quantitatively analyzed where possible or qualitatively analyzed where data are insufficient to quantify impacts. The impacts are compared to the significance criteria to determine the level of significance.

The impact sections of this chapter focus on those impacts that are considered potentially significant per the requirements of CEQA. An impact is considered significant if it leads to a "substantial, or potentially substantial, adverse change in the environment." Impacts from the project fall within one of the following categories:

> **Beneficial:** Impacts will have a positive effect on the resource.
>
> **No Impact:** There would be no impact to the identified resource as a result of the project.
>
> **Less than Significant:** Some impacts may result from the project; however, they are judged to be less than significant. Impacts are frequently considered less than significant when the changes are minor relative to the size of the available resource base or would not change an existing resource. A "less than significant impact" applies where the environmental impact does not exceed the significance threshold.

Potentially Significant but Mitigation Measures Can Reduce Impacts to Less Than Significant: Significant adverse impacts may occur; however, with proper mitigation, the impacts can be reduced to less than significant.

Potentially Significant or Significant Impacts: Adverse impacts may occur that would be significant even after mitigation measures have been applied to minimize their severity. A "potentially significant or significant impacts" applies where the environmental impact exceeds the significance threshold, or information was lacking to make a finding of insignificance.

It is important to note that CEQA will also apply to individual projects at the time any permits are submitted in the future in response to the regulation or regulations that may be approved by the Board and the potential for any control equipment or other design modifications to a refinery to have secondary adverse environmental impacts will be evaluated at that time. Should projects be subject to applicable permitting requirements because they are ultimately found to exceed the refinery-wide emissions limits for SO_2 and PM2.5 or the updated HRA shows that additional risk reduction measures are required, a separate project-specific CEQA analysis will be conducted at the time of permitting to ensure that any significant adverse environmental impacts are identified and mitigated, as necessary, or avoided.

3.1.4 MITIGATION MEASURES

If significant adverse environmental impacts are identified, the CEQA Guidelines require a discussion of measures that could either avoid or substantially reduce any adverse environmental impacts to the greatest extent feasible (CEQA Guidelines §15126.4). The analyses in this chapter describe the potential for significant adverse impacts and identify mitigation measures where appropriate. This section describes feasible mitigation measures that could minimize potentially significant or significant impacts that may result from project approval. CEQA Guidelines (§15370) defines mitigation to include:

- Avoiding the impact altogether by not taking a certain action or parts of an action.

- Minimizing impacts by limiting the degree or magnitude of the action and its implementation.

- Rectifying the impact by repairing, rehabilitating or restoring the impacted environment.

- Reducing or eliminating the impact over time by preservation and maintenance operations during the life of the action.

- Compensating for the impact by replacing or providing substitute resources or environments.

In accordance with CEQA statutes (§21081.6), a mitigation and monitoring program would be required to be adopted to demonstrate and monitor compliance with any mitigation measures identified in this EIR. The program would identify specific mitigation measures to be undertaken, when the measure would be implemented, and the agency responsible for oversight, implementation and enforcement.

3.1.5 CUMULATIVE IMPACTS

CEQA Guidelines §15130(a) requires an EIR to discuss cumulative impacts of a project when the project's incremental effect is cumulatively considerable. An EIR evaluating the environmental impact of air quality regulations essentially evaluates the cumulative impacts associated with a variety of regulatory activities. As such, this EIR evaluates the cumulative environmental impacts associated with implementation of other air quality regulations as outlined in the 2017 Clean Air Plan, the most recent air plan for the Bay Area (BAAQMD, 2017). The area evaluated for cumulative impacts in this EIR is the area within the jurisdiction of the District, an area encompassing 5,600 square miles, which includes all of Alameda, Contra Costa, Marin, San Francisco, San Mateo, Santa Clara, and Napa Counties, and portions of southwestern Solano and southern Sonoma counties.

CHAPTER 3.2

AIR QUALITY IMPACTS

- Introduction
- Environmental Setting
- Regulatory Setting
- Significance Criteria
- Air Quality Impacts

3.2 AIR QUALITY

This subchapter of the EIR evaluates the potential air quality impacts associated with implementation of Rule~~s 11-18 and/or~~ 12-16. Rule 12-16 would establish numeric emission limits on specific refinery and associated facilities within the Bay Area.~~ Rule 11-18 would reduce exposure to TAC emissions from a number of stationary sources within the Bay Area, including refineries.~~

As discussed in the Initial Study, implementation ~~of Rule 11-18 would reduce risk from facilities that emit toxic air contaminants throughout the Bay Area. However, certain risk reduction measures have the potential to increase emissions of other pollutants, such as GHGs and criteria pollutants. Implementation~~ of Rule 12-16 would prevent refinery emissions of GHGs and some criteria pollutants from increasing. Similarly, secondary adverse air quality impacts could occur from installing control equipment at individual refineries in response to changes that could increase emissions some of criteria pollutants. Adverse impacts include increased criteria pollutant and TAC emissions from certain types of air pollution control equipment. The NOP/IS (see Appendix A) determined that air quality impacts of the proposed new rule~~s are~~ is potentially significant. Project-specific and cumulative adverse air quality impacts associated with the proposed new rule~~s~~ on air contaminants (including criteria air pollutants and TACs) have been evaluated in Chapter 3.2 of this EIR.

3.2.1 ENVIRONMENTAL SETTING

3.2.1.1 Criteria Pollutants

Ambient Air Quality Standards

It is the responsibility of the Air District to ensure that state and federal ambient air quality standards (AAQS) are achieved and maintained in its geographical jurisdiction. Health-based air quality standards have been established by California and the federal government for the following criteria air pollutants: ozone (O_3), carbon monoxide (CO), nitrogen dioxide (NO_2), particulate matter (PM10 and PM2.5), sulfur dioxide (SO_2), and lead (Pb). These standards were established to protect sensitive receptors with a margin of safety from adverse health impacts due to exposure to air pollution. California has also established standards for sulfate, visibility, hydrogen sulfide, and vinyl chloride. The state and national NAAQS for each of these pollutants and their effects on health are summarized in Table 3.2-1.

TABLE 3.2-1

Federal and State Ambient Air Quality Standards

	STATE STANDARD	FEDERAL PRIMARY STANDARD	MOST RELEVANT EFFECTS
AIR POLLUTANT	CONCENTRATION/ AVERAGING TIME	CONCENTRATION/ AVERAGING TIME	
Ozone	0.09 ppm, 1-hr. avg. > 0.070 ppm, 8-hr	No Federal 1-hr standard 0.070 ppm, 8-hr avg. >	(a) Short-term exposures: (1) Pulmonary function decrements and localized lung edema in humans and animals (2) Risk to public health implied by alterations in pulmonary morphology and host defense in animals; (b) Long-term exposures: Risk to public health implied by altered connective tissue metabolism and altered pulmonary morphology in animals after long-term exposures and pulmonary function decrements in chronically exposed humans; (c) Vegetation damage; (d) Property damage
Carbon Monoxide	9.0 ppm, 8-hr avg. > 20 ppm, 1-hr avg. >	9 ppm, 8-hr avg.> 35 ppm, 1-hr avg.>	(a) Aggravation of angina pectoris and other aspects of coronary heart disease; (b) Decreased exercise tolerance in persons with peripheral vascular disease and lung disease; (c) Impairment of central nervous system functions; (d) Possible increased risk to fetuses
Nitrogen Dioxide	0.030 ppm, annual avg. 0.18 ppm, 1-hr avg. >	0.053 ppm, ann. avg.> 0.100 ppm, 1-hr avg.	(a) Potential to aggravate chronic respiratory disease and respiratory symptoms in sensitive groups; (b) Risk to public health implied by pulmonary and extra-pulmonary biochemical and cellular changes and pulmonary structural changes; (c) Contribution to atmospheric discoloration
Sulfur Dioxide	0.04 ppm, 24-hr avg.> 0.25 ppm, 1-hr. avg. >	No Federal 24-hr Standard> 0.075 ppm, 1-hr avg.>	(a) Bronchoconstriction accompanied by symptoms which may include wheezing, shortness of breath and chest tightness, during exercise or physical activity in persons with asthma
Suspended Particulate Matter (PM10)	20 µg/m^3, ann. arithmetic mean > 50 µg/m^3, 24-hr average>	No Federal annual Standard 150 µg/m^3, 24-hr avg.>	(a) Excess deaths from short-term exposures and exacerbation of symptoms in sensitive patients with respiratory disease; (b) Excess seasonal declines in pulmonary function, especially in children
Suspended Particulate Matter (PM2.5)	12 µg/m^3, annual arithmetic mean> No State 24-hr Standard	12 µg/m^3, annual arithmetic mean> 35 µg/m^3, 24-hour average>	Decreased lung function from exposures and exacerbation of symptoms in sensitive patients with respiratory disease; elderly; children.
Sulfates	25 µg/m^3, 24-hr avg. >=	No Federal Standard	(a) Decrease in ventilatory function; (b) Aggravation of asthmatic symptoms; (c) Aggravation of cardio-pulmonary disease; (d) Vegetation damage; (e) Degradation of visibility; (f) Property damage
Lead	1.5 µg/m^3, 30-day avg. >= No State Calendar Quarter Standard No State 3-Month Rolling Avg. Standard	No Federal 30-day avg. Standard 1.5 µg/m^3, calendar quarter> 0.15 µg/m^3 3-Month Rolling average	(a) Increased body burden; (b) Impairment of blood formation and nerve conduction
Visibility-Reducing Particles	In sufficient amount to give an extinction coefficient >0.23 inverse kilometers (visual range to less than 10 miles) with relative humidity less than 70%, 8-hour average (10am – 6pm PST)	No Federal Standard	Visibility based standard, not a health based standard. Nephelometry and AISI Tape Sampler; instrumental measurement on days when relative humidity is less than 70 percent
Hydrogen Sulfide	0.03 ppm (42 ug/m^3); 1 hour avg.	No Federal Standard	Odor threshold.
Vinyl Chloride	0.01 ppm (26 ug/m^3); 24 hour avg.	No Federal Standard	Regulated as a toxic air contaminant as a carcinogen with no acceptable level of exposure. 0.01 ppm was the limit of detection in 1978 when the standard was established

U.S. EPA requires CARB and Air District to measure the ambient levels of air pollution to determine compliance with the NAAQS. To comply with this mandate, the Air District monitors levels of various criteria pollutants at 27 monitoring stations within the San Francisco Bay Area. A summary of the 2015 maximum concentration and number of days exceeding state and federal ambient air standards at the Air District monitoring stations are presented in Table 3.2-2.

TABLE 3.2-2
Bay Area Air Pollution Summary – 2015

MONITORING STATIONS	OZONE						CARBON MONOXIDE			NITROGEN DIOXIDE				SULFUR DIOXIDE				PM $_{10}$				PM $_{2.5}$				
	Max 1-hr	Cal 1-hr Days	Max 8-hr	Nat 8-Hr Days	Cal 8-hr Days	3-Yr Avg	Max 1-hr	Max 8-hr	Nat/ Cal Days	Max 1-Hr	Ann Avg	Nat 8-hr Days	Cal 8-hr Days	Max 1-hr	Max 24-hr	Nat 1-Hr Days	Cal 24-hr Days	Ann Avg	Max 24-hr	Nat Days	Cal Days	Max 24-hr	Nat 24-hr Days	3-Yr Avg	Ann Avg	3-Yr Avg
North Counties	(ppb)						(ppm)			(ppb)				(ppb)				(μg/m^3)				(μg/m^3)				
Napa*	79	0	69	0	0	61	3.3	1.6	0	43	8	0	0	-	-	-	-	18.6	50	0	0	38.2	1	27	10.6	11.4
San Rafael	81	0	70	0	0	61	1.4	0.9	0	44	11	0	0	-	-	-	-	16.1	42	0	0	36.3	2	26	8.6	10.0
Sebastopol*	68	0	62	0	0	*	1.3	0.9	0	37	5	0	0	-	-	-	-	-	-	-	-	29.9	0	*	6.8	*
Vallejo	85	0	70	0	1	61	2.4	1.9	0	44	8	0	0	5	1.7	0	0	-	-	-	-	41.4	3	29	9.6	9.8
Coast/Central Bay																										
Laney College Fwy*	-	-	-	-	-	-	2.7	1.6	0	106	18	1	0	-	-	-	-	-	-	-	-	37.2	1	*	10.0	*
Oakland	94	0	74	2	2	52	2.4	1.4	0	48	11	0	0	-	-	-	-	-	-	-	-	44.7	1	25	8.3	9.1
Oakland-West*	91	0	64	0	0	49	4.7	2.6	0	57	14	0	0	21.6	3.9	0	0	-	-	-	-	38.7	3	29	10.2	10.8
Richmond	-	-	-	-	-	-	-	-	-	-	-	-		-12	2.8	0	0	-	-	-	-	-	-	-	-	-
San Francisco	85	0	67	0	0	48	1.8	1.3	0	71	12	0	0	-	-	-	-	19.2	47	0	0	35.4	0	25	7.6	8.4
San Pablo*	84	0	62	0	0	55	2	1.1	0	46	9	0	0	10.7	2.4	0	0	18.6	43	0	0	33.2	0	27	8.9	10.5
Eastern District																										
Bethel Island	80	0	72	1	2	66	1.1	0.9	0	29	5	0	0	8.8	1.9	0	0	13.6	33	0	0	-	-	-	-	-
Concord	88	0	73	2	4	64	1.4	1.3	0	33	7	0	0	6.7	2	0	0	13.1	24	0	0	31	0	23	8.8	7.7
Crockett	-	-	-	-	-	-	-	-	-	-	-	-	-	-20.5	3.7	0	0	-	-	-	-	-	-	-	-	-
Fairfield	84	0	72	1	1	63	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Livermore	105	1	81	7	7	73	-	-	-	50	10	0	0	-	-	-	-	-	-	-	-	31.1	0	28	8.8	8.2
Martinez	-	-	-	-	-	-	-	-	-	-	-	-	-	14.7	4.8	0	0	-	-	-	-	-	-	-	-	-
Patterson Pass	99	4	82	5	6	*	-	-	-	19	3	0	0	-	-	-	-	-	-	-	-	-	-	-	-	-
San Ramon	106	1	84	6	6	70	-	-	-	37	6	0	0	-	-	-	-	-	-	-	-	-	-	-	-	-
South Central Bay																										
Hayward	103	2	84	2	2	65	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Redwood City	86	0	71	1	1	59	3.4	1.6	0	48	11	0	0	-	-	-	-	-	-	-	-	34.6	0	24	5.7	7.8
Santa Clara Valley																										
Gilroy	95	1	78	3	3	67	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42.2	2	18	7.2	7.5
Los Gatos	100	1	84	4	5	67	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
San Jose	94	0	81	2	2	63	2.4	1.8	0	49	13	0	0	3.1	1.1	0	0	22	58	0	1	49.4	2	30	10.0	10.2
San Jose Freeway*	-	-	-	-	-	-	2.7	2	0	61	18	0	0	-	-	-	-	-	-	-	-	46.9	1	*	8.4	*
San Martin	98	1	83	4	4	70	-	-	-	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-
Total Days over Standard		**7**		**12**	**12**				**0**		**1**	**0**			**0**	**0**				**0**	**1**		**9**			

*Air monitoring at Sebastopol began in January 2014. Therefore, 3-year average statistics for ozone and PM2.5 are not available. The Sebastopol site replaced the Santa Rosa site which closed on December 13, 2013.
Ozone monitoring using the federally accepted method began at Patterson Pass on April 1, 2015. Therefore, 3-year average ozone statistics are not available.
Near-road air monitoring at Laney College Freeway began in February 2014. Therefore, 3-year average PM2.5 statistics are not available.
Near-road air monitoring at San Jose Freeway began in September 2014. Therefore, 3-year average PM2.5 statistics are not available.
(ppb) = parts per billion (ppm) = parts per million, (μg/m^3) = micrograms per cubic meter
.

Air quality conditions in the San Francisco Bay Area have improved since the Air District was created in 1955. The long-term trend of ambient concentrations of air pollutants and the number of days on which the region exceeds (AAQS) have generally declined, although some year-to-year variability primarily due to meteorology, causes some short-term increases in the number of exceedance days (see Table 3.2-3). The Air District is in attainment of the State AAQS for CO, NO_2, and SO_2. However, the Air District does not comply with the State 24-hour PM10 standard. The Air District is unclassifiable/attainment for the federal CO, NO_2, SO_2, Pb, and PM10 standards. A designation of unclassifiable/attainment means that EPA has determined to have sufficient evidence to find the area either is attaining or is likely attaining the NAAQS.

The 2015 air quality data from the Air District monitoring stations are presented in Table 3.2-2. No monitoring stations measured an exceedance of any of the state or federal AAQS for CO, SO_2, and Pb. There was one exceedance of the federal NO_2 AAQS at one monitoring station in 2015, although the area did not violate the NAAQS. All monitoring stations were in compliance with the federal PM10 standards. The California 24-hour PM10 standard was exceeded on one day in 2015, at the San Jose monitoring station (see Table 3.2-2).

The Bay Area is designated as a non-attainment area for the federal and state 8-hour ozone standard and the federal 24-hour PM2.5 standard. The state 8-hour ozone standard was exceeded on 12 days in 2015 at one site or more in the Air District; most frequently in the Eastern District (Livermore, Patterson Pass, and San Ramon) (see Table 3.2-2). The federal 8-hour ozone standard was exceeded on 12 days in 2015. The federal 24-hour PM2.5 standard was exceeded at one or more Bay Area station on nine days in 2015, most frequently at the Vallejo and Oakland-West stations.

TABLE 3.2-3

Bay Area Air Quality Summary
Days over Standards

YEAR	OZONE			CARBON MONOXIDE				NOx		SULFUR DIOXIDE		PM10		PM2.5
	8-Hr	1-Hr	8-Hr	1-Hr		8-Hr		1-Hr		1-Hr	24-Hr	24-Hr*		24-Hr
	Nat	Cal	Cal	Nat	Cal	Nat	Cal	Nat	Cal	Nat	Cal	Nat	Cal	Nat
2006	20	18	22	0	0	0	0	1	0	0	0	0	15	10
2007	8	4	9	0	0	0	0	0	0	0	0	0	4	14
2008	19	9	20	0	0	0	0	0	0	2	0	0	5	12
2009	11	11	13	0	0	0	0	0	0	0	0	0	1	11
2010	11	8	11	0	0	0	0	0	0	0	0	0	2	6
2011	9	5	10	0	0	0	0	0	0	0	0	0	3	8
2012	8	3	8	0	0	0	0	1	0	0	0	0	2	3
2013	3	3	3	0	0	0	0	0	0	0	0	0	6	13
2014	9	3	10	0	0	0	0	0	0	0	0	0	2	3
2015	12	7	12	0	0	0	0	1	0	0	0	0	1	9

3.2.1.2 Criteria Pollutant Health Effects

3.2.1.2.1 Ozone

Ozone is not emitted directly from pollution sources. Instead ozone is formed in the atmosphere through complex chemical reactions between hydrocarbons, or reactive organic gases (ROG, also commonly referred to as volatile organic compounds or VOC), and nitrogen oxides (NOx), in the presence of sunlight. ROG and NOx are referred to as ozone precursors.

Ozone, a colorless gas with a sharp odor, is a highly reactive form of oxygen. High ozone concentrations exist naturally in the stratosphere. Some mixing of stratospheric ozone downward through the troposphere to the earth's surface does occur; however, the extent of ozone mixing is limited. At the earth's surface in sites remote from urban areas ozone concentrations are normally very low (0.03-0.05 ppm). While ozone is beneficial in the stratosphere because it filters out skin-cancer-causing ultraviolet radiation, ground level ozone is harmful, is a highly reactive oxidant, which accounts for its damaging effects on human health, plants and materials at the earth's surface.

Ozone is harmful to public health at high concentrations near ground level. Ozone can damage the tissues of the lungs and respiratory tract. High concentrations of ozone irritate the nose, throat, and respiratory system and constrict the airways. Ozone also can aggravate other respiratory conditions such as asthma, bronchitis, and emphysema, causing increased hospital admissions. Repeated exposure to high ozone levels can make people more susceptible to respiratory infection and lung inflammation and permanently damage lung tissue. Ozone can also have negative cardiovascular impacts, including chronic hardening of the arteries and acute triggering of heart attacks. Children are most at risk as they tend to be active and outdoors in the summer when ozone levels are highest. Seniors and people with respiratory illnesses are also especially sensitive to ozone’s effects. Even healthy adults can be affected by working or exercising outdoors during high ozone levels.

The propensity of ozone for reacting with organic materials causes it to be damaging to living cells, and ambient ozone concentrations in the Bay Area are occasionally sufficient to cause health effects. Ozone enters the human body primarily through the respiratory tract and causes respiratory irritation and discomfort, makes breathing more difficult during exercise, reducing the respiratory system's ability to remove inhaled particles and fight infection while long-term exposure damages lung tissue. People with respiratory diseases, children, the elderly, and people who exercise heavily are more susceptible to the effects of ozone.

Plants are sensitive to ozone at concentrations well below the health-based standards and ozone is responsible for significant crop damage. Ozone is also responsible for damage to forests and other ecosystems.

3.2.1.2.2 Volatile Organic Compounds (VOCs)

It should be noted that there are no state or national ambient air quality standards for VOCs because they are not classified as criteria pollutants. VOCs are regulated, however, because VOC emissions contribute to the formation of ozone. They are also transformed into organic aerosols in the atmosphere, contributing to higher PM10 and lower visibility levels.

Although health-based standards have not been established for VOCs, health effects can occur from exposures to high concentrations of VOCs because of interference with oxygen uptake. In general, ambient VOC concentrations in the atmosphere are suspected to cause coughing, sneezing, headaches, weakness, laryngitis, and bronchitis, even at low concentrations. Some hydrocarbon components classified as VOC emissions are thought or known to be hazardous. Benzene, for example, one hydrocarbon component of VOC emissions, is known to be a human carcinogen.

VOC emissions result primarily from incomplete fuel combustion and the evaporation of paints, solvents and fuels. Mobile sources are the largest contributors to VOC emissions. Stationary sources include processes that use solvents (such as manufacturing, degreasing, and coating operations) and petroleum refining, and marketing. Area-wide VOC sources include consumer products, pesticides, aerosol and architectural coatings, asphalt paving and roofing, and other evaporative emissions.

3.2.1.2.3 Carbon Monoxide (CO)

CO is a colorless, odorless, relatively inert gas. It is a trace constituent in the unpolluted troposphere, and is produced by both natural processes and human activities. In remote areas far from human habitation, carbon monoxide occurs in the atmosphere at an average background concentration of 0.04 ppm, primarily as a result of natural processes such as forest fires and the oxidation of methane. Global atmospheric mixing of CO from urban and industrial sources creates higher background concentrations (up to 0.20 ppm) near urban areas. The major source of CO in urban areas is incomplete combustion of carbon-containing fuels, mainly gasoline used in mobile sources. Consequently, CO concentrations are generally highest in the vicinity of major concentrations of vehicular traffic.

CO is a primary pollutant, meaning that it is directly emitted into the air, not formed in the atmosphere by chemical reaction of precursors, as is the case with ozone and other secondary pollutants. Ambient concentrations of CO in the District exhibit large spatial and temporal variations, due to variations in the rate at which CO is emitted, and in the meteorological conditions that govern transport and dilution. Unlike ozone, CO tends to reach high concentrations in the fall and winter months. The highest concentrations frequently occur on weekdays at times consistent with rush hour traffic and late night during the coolest, most stable atmospheric portion of the day.

When CO is inhaled in sufficient concentration, it can displace oxygen and bind with the hemoglobin in the blood, reducing the capacity of the blood to carry oxygen. Individuals most at risk from the effects of CO include heart patients, fetuses (unborn babies), smokers, and people who exercise heavily. Normal healthy individuals are affected at higher concentrations, which may cause impairment of manual dexterity, vision, learning ability, and performance of work. The results of studies concerning the combined effects of CO and other pollutants in animals have shown a synergistic effect after exposure to CO and ozone.

3.2.1.2.4 Particulate Matter (PM10 & PM2.5)

Particulate matter, or PM, consists of microscopically small solid particles or liquid droplets suspended in the air. PM can be emitted directly into the air or it can be formed from secondary reactions involving gaseous pollutants that combine in the atmosphere. Particulate pollution is primarily a problem in winter, accumulating when cold, stagnant weather comes into the Bay Area. PM is usually broken down further into two size distributions, PM10 and PM2.5. Of great concern to public health are the particles small enough to be inhaled into the deepest parts of the lung. Respirable particles (particulate matter less than about 10 micrometers in diameter) can accumulate in the respiratory system and aggravate health problems such as asthma, bronchitis and other lung diseases. Children, the elderly, exercising adults, and those suffering from asthma are especially vulnerable to adverse health effects of PM10 and PM2.5.

A consistent correlation between elevated ambient particulate matter (PM10 and PM2.5) levels and an increase in mortality rates, respiratory infections, number and severity of asthma attacks and the number of hospital admissions has been observed in different parts of the United States and various areas around the world. Studies have reported an association between long-term exposure to air pollution dominated by fine particles (PM2.5) and increased mortality, reduction in life-span, and an increased mortality from lung cancer. (BAAQMD 2012)

Daily fluctuations in fine particulate matter concentration levels have also been related to hospital admissions for acute respiratory conditions, to school and kindergarten absences, to a decrease in respiratory function in normal children and to increased medication use in children and adults with asthma. Studies have also shown lung function growth in children is reduced with long-term exposure to particulate matter. The elderly, people with pre-existing respiratory and/or cardiovascular disease and children appear to be more susceptible to the effects of PM10 and PM2.5. (BAAQMD 2012)

3.2.1.2.5 Nitrogen Dioxide (NO_2)

NO_2 is a reddish-brown gas with a bleach-like odor. Nitric oxide (NO) is a colorless gas, formed from the nitrogen (N_2) and oxygen (O_2) in air under conditions of high temperature and pressure which are generally present during combustion of fuels; NO reacts rapidly with the oxygen in air to form NO_2. NO_2 is responsible for the brownish tinge of polluted air. The two gases, NO and NO_2, are referred to collectively as nitrogen oxides or NOx. In the presence of sunlight, NO_2 reacts to form nitric oxide and an oxygen atom. The oxygen atom can react further to form ozone, via a complex series of chemical reactions involving hydrocarbons. Nitrogen dioxide may also react to form nitric acid (HNO_3) which reacts further to form nitrates, which are a component of PM10.

NO_2 is a respiratory irritant and reduces resistance to respiratory infection. Children and people with respiratory disease are most susceptible to its effects.

3.2.1.2.6 Sulfur Dioxide (SO_2)

SO_2 is a colorless gas with a sharp odor. It reacts in the air to form sulfuric acid (H_2SO_4), which contributes to acid precipitation, and sulfates, which are a component of PM10 and PM2.5. Most of the SO_2 emitted into the atmosphere is produced by the burning of sulfur-containing fuels.

At sufficiently high concentrations, SO_2 affects breathing and the lungs' defenses, and can aggravate respiratory and cardiovascular diseases. Asthmatics and people with chronic lung disease or cardiovascular disease are most sensitive to its effects. SO_2 also causes plant damage, damage to materials, and acidification of lakes and streams.

3.2.1.3 Current Emissions Inventory

An emission inventory is a detailed estimate of air pollutant emissions from a range of sources in a given area, for a specified time period. Future projected emissions incorporate current levels of control on sources, growth in activity in the Air District and implementation of future programs that affect emissions of air pollutants. Table 3.2-4 shows the inventory of the major sources of particulate matter (including PM10 and PM2.5. Note that many of the stationary source combustion emissions in this table are from petroleum refining operations.

3.2.1.3.1 Ozone

NOx and VOC emissions are decreasing state-wide and in the San Francisco Bay Area since 1975 and are projected to continue to decline. VOC emissions result primarily from incomplete fuel combustion and the evaporation of paints, solvents and fuels. Mobile sources are the largest contributors to VOC emissions. Stationary sources include processes that use solvents (such as manufacturing, degreasing, and coating operations) and petroleum refining, and marketing. Area-wide VOC sources include consumer products, pesticides, aerosol and architectural coatings, asphalt paving and roofing, and other evaporative emissions. About 42 percent of anthropogenic ROG emissions in the Bay Area are from mobile source emissions, while 26 percent are from petroleum and solvent evaporation (BAAQMD, 2017). Refineries emit approximately 1.5 percent of the total ROG emissions in the District.

TABLE 3.2-4

2011 Air Emission Inventory – Annual Average (tons per day)

SOURCE CATEGORY	ROG	CO	NOx	SO2	PM10	PM2.5
Petroleum Refining Processes	4.2	1.8	0.5	0.8	0.3	0.2
Other Industrial/Commercial Processes	9.8	0.9	1.7	6.9	10	6
Organic Compounds Evaporation	67.1	0	0	0	0	0
Combustion – Stationary Sources	11	113.8	48.3	10.2	17.9	17.3
Off-Road Mobile Sources	45.2	394.1	75.7	1.3	5.1	5.1
Aircraft	4.1	27.1	12.3	1.1	0.3	0.2
On-Road Motor Vehicles	80.8	773.9	176.6	0.9	13.2	7.2
Miscellaneous	51.2	15	0.5	0.1	58.5	9.5
Total Emissions	**273.4**	**1326.6**	**315.6**	**21.3**	**105.3**	**45.5**

Source: Bay Area Emission Inventory Summary Report: Criteria Air Pollutants (BAAQMD, 2014)

Approximately 84 percent of NOx emissions in the Bay Area are produced by the combustion of fuels. Mobile sources of NOx include motor vehicles, aircraft, trains, ships, recreation boats, industrial and construction equipment, farm equipment, off-road recreational vehicles, and other equipment. NOx and VOC emissions have been reduced for both stationary and mobile sources. Stationary sources of VOC and NOx have been substantially reduced due to stringent District regulations (BAAQMD, 2017). Refineries emit approximately 0.16 percent of the total NOx emissions in the District.

3.2.1.3.2 Particulate Matter

Particulate matter (both PM10 and PM2.5) is a diverse mixture of suspended particles and liquid droplets (aerosols). PM includes elements such as carbon and metals; compounds such as nitrates, organics, and sulfates; and complex mixtures such as diesel exhaust, wood smoke, and soil. Unlike the other criteria pollutants which are individual chemical compounds, PM includes all particles that are suspended in the air. PM is both directly emitted (referred to as direct PM or primary PM) and also formed in the atmosphere through reactions among different pollutants (this is referred to as indirect or secondary PM).

PM is generally characterized on the basis of particle size. Ultra-fine PM includes particles less than 0.1 microns in diameter. Fine PM (PM2.5) consists of particles 2.5 microns or less in diameter. PM10 consists of particles 10 microns or less in diameter. Total suspended particulates (TSP) includes suspended particles of any size.

Combustion of fossil fuels and biomass, primarily wood, from various sources are the primary contributors of directly-emitted Bay Area PM2.5 (BAAQMD, 2017). Biomass combustion concentrations are about 3-4 times higher in winter than during the other seasons, and its contribution to peak PM2.5 is greater. The increased winter biomass combustion sources reflect increased residential wood-burning during the winter season. Refineries emit approximately 0.3 percent of the total PM10 emissions and 0.4 percent of the total PM2.5 emissions in the District.

3.2.1.4 Non-Criteria Pollutants Health Effects

Although the primary mandate of the BAAQMD is attaining and maintaining the national and state Ambient Air Quality Standards for criteria pollutants within the BAAQMD jurisdiction, the BAAQMD also has a general responsibility to control, and where possible, reduce public exposure to airborne toxic compounds. TACs are a defined set of airborne pollutants that may pose a present or potential hazard to human health. TACs can be emitted directly and can also be formed in the atmosphere through reactions among different pollutants. The health effects associated with TACs are quite diverse and generally are assessed locally, rather than regionally. TACs can cause long-term health effects such as cancer, birth defects, neurological damage, asthma, bronchitis or genetic damage; or short-term acute affects such as eye watering, respiratory irritation, running nose, throat pain, and headaches. TACs are separated into carcinogens and non-carcinogens based on the nature of the pollutant. Carcinogens are assumed to have no safe threshold below which health impacts would not occur. Non-carcinogenic substances differ in that there is generally assumed to be a safe level of exposure below which no negative health impact is expected to occur. These levels are determined on a pollutant-by-pollutant basis. The air toxics program was established as a separate and complementary program designed to evaluate and reduce adverse health effects resulting from exposure to TACs.

The major elements of the District’s air toxics program are outlined below.

- Preconstruction review of new and modified sources for potential health impacts, and the requirement for new/modified sources with TAC emissions that exceed a specified threshold to use BACT.
- The Air Toxics Hot Spots Program, designed to identify industrial and commercial facilities that may result in locally elevated ambient concentrations of TACs, to report significant emissions to the affected public, and to reduce unacceptable health risks.
- Control measures designed to reduce emissions from source categories of TACs, including rules originating from the state Toxic Air Contaminant Act and the federal Clean Air Act.
- The TAC emissions inventory, a database that contains information concerning routine and predictable emissions of TACs from permitted stationary sources.
- Ambient monitoring of TAC concentrations at a number of sites throughout the Bay Area.

3.2.1.4.1 TAC Health Effects

TACs can cause or contribute to a wide range of health effects. Acute (short-term) health effects may include eye and throat irritation. Chronic (long-term) exposure to TACs may cause more severe effects such as neurological damage, hormone disruption, developmental defects, and cancer. CARB has identified roughly 200 TACs, including diesel particulate matter (diesel PM) and environmental tobacco smoke.

Unlike criteria pollutants which are subject to ambient air quality standards, TACs are primarily regulated at the individual emissions source level based on risk assessment. Human outdoor exposure risk associated with an individual air toxic species is calculated as its ground-level concentration multiplied by an established unit risk factor for that air toxic species. Total risk due to TACs is the sum of the individual risks associated with each air toxic species.

Occupational health studies have shown diesel PM to be a lung carcinogen as well as a respiratory irritant. Benzene, present in gasoline vapors and also a byproduct of combustion, has been classified as a human carcinogen and is associated with leukemia. 1,3-butadiene, produced from motor vehicle exhaust and other combustion sources, has also been associated with leukemia. Reducing 1,3-butadiene also has a co-benefit in reducing the air toxic acrolein.

Acetaldehyde and formaldehyde are emitted from fuel combustion and other sources. They are also formed photo-chemically in the atmosphere from other compounds. Both compounds have been found to cause nasal cancers in animal studies and are also associated with skin and respiratory irritation. Human studies for carcinogenic effects of acetaldehyde are sparse but, in combination with animals studies, sufficient to support classification as a probable human carcinogen. Formaldehyde has been associated with nasal sinus cancer and nasopharyngeal cancer, and possibly with leukemia.

The primary health risk of concern due to exposure to TACs is the risk of contracting cancer. The carcinogenic potential of TACs is a particular public health concern because many scientists currently believe that there are not "safe" levels of exposure to carcinogens without some risk to causing cancer. The proportion of cancer deaths attributable to air pollution has not been estimated using epidemiological methods. Based on ambient air quality monitoring, and using OEHHA cancer risk factors,[1] the estimated lifetime cancer

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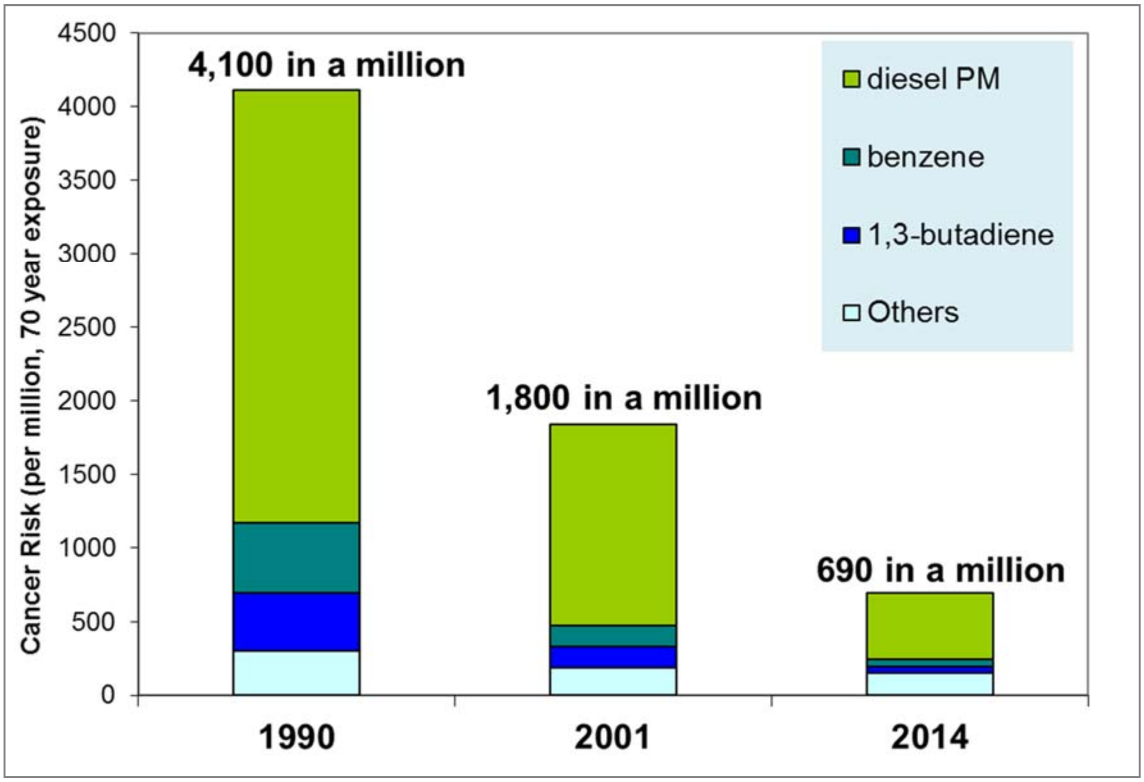
[1] See CARB's Risk Management Guidance for Stationary Sources of Air Toxics, Discussion Draft, May 27, 2015, https://www.arb.ca.gov/toxics/rma/rma_guidancedraft052715.pdf and the Office Environmental Health Hazard Assessment's toxicity values at http://oehha.ca.gov/media/CPFs042909.pdf. The cancer risk estimates shown in Figure 3.2-1 are higher than the estimates provided in documents such as the Bay Area 2010 Clean Air Plan and the April 2014 CARE report entitled *Improving Air Quality and Health in Bay Area Communities*. It should be emphasized that the higher risk estimates shown in Figure 3.2-1 are due solely to changes in the methodology used to estimate cancer risk, and not to any actual increase in TAC emissions or population exposure to TACs.

risk for Bay Area residents, over a 70-year lifespan from all TACs combined, declined from 4,100 cases per million in 1990 to 690 cases per million people in 2014, as shown in Figure 3.2-1. This represents an 80 percent decrease between 1990 and 2014 (BAAQMD, 2016).

The cancer risk related to diesel PM, which accounts for most of the cancer risk from TACs, has declined substantially over the past 15-20 years as a result of ARB regulations and Air District programs to reduce emissions from diesel engines. However, diesel PM still accounts for roughly 60 percent of the total cancer risk related to TACs.

FIGURE 3.2-1 Cancer-Risk Weighted Toxics Trends



Source: BAAQMD, 2016

3.2.1.4.2 Air Toxics Emission Inventory

The BAAQMD maintains a database that contains information concerning emissions of TACs from permitted stationary sources in the Bay Area. This inventory, and a similar inventory for mobile and area sources compiled by CARB, is used to plan strategies to reduce public exposure to TACs. The detailed emissions inventory is reported in the BAAQMD, Toxic Air Contaminant Control Program, 2010 Annual Report (BAAQMD, 2015). The 2010 emissions inventory continues to show decreasing emissions of many TACs in the Bay Area.

3.2.1.4.3 Ambient Monitoring Network

Table 3.2-5 contains a summary of average ambient concentrations of TACs measured at monitoring stations in the Bay Area by the District in 2015.

TABLE 3.2-5

Summary of 2014 BAAQMD Ambient Air Toxics Monitoring Data

Compound	**Max. Conc. (ppb)** (1)	**Min. Conc. (ppb)** (2)	**Mean Conc. (ppb)** (3)
1,3-Butadiene	0.376	0.000	0.038
Acetaldehyde(4)	5.71	0.42	1.70
Acetone	26.54	0.156	3.922
Acetonitrile	0.314	0.000	0.015
Acrolein(5)	0.060	0.000	0.077
Acrylonitrile	0.060	0.000	0.000
Benzene	1.169	0.000	0.201
Carbon Tetrachloride	0.130	0.066	0.093
Chloroform	0.147	0.000	0.218
Dichloromethane	3.473	0.000	0.076
Ethyl Alcohol	40.046	0.286	5.570
Ethylbenzene	0.979	0.000	0.076
Ethylene Dibromide	0.000	0.000	0.000
Ethylene Dichloride	0.011	0.000	0.000
Formaldehyde	8.12	1.16	2.78
Freon- 113	9.832	0.048	0.147
Methyl Chloroform	3.776	0.000	0.036
Methyl Ethyl Ketone	0.876	0.000	0.253
Tetrachloroethylene	0.712	0.000	0.036
Toluene	4.006	0.000	0.501
Trichloroethylene	6.370	0.000	0.016
Trichlorofluoromethane	1.835	0.090	0.283
Vinyl Chloride	0.000	0.000	0.000
m/p-Xylene	2.788	0.000	0.264
o-Xylene	1.198	0.000	0.099

Source: BAAQMD, 2017

NOTES: Table 3.2-5 summarizes the results of the Air District gaseous toxic air contaminant monitoring network for the year 2015. These data represent monitoring results at 19 separate sites at which samples were collected.

(1) "Maximum Conc." is the highest daily concentration measured at any of the 19 monitoring sites.

(2) "Minimum Conc." is the lowest daily concentration measured at any of the 19 monitoring sites.

(3) "Mean Conc." is the arithmetic average of the air samples collected in 2014 at the 25 monitoring sites.

(4) Acetaldehyde and formaldehyde concentrations reflect measurements from one monitoring site (San Jose-Jackson).

(5) The Air District discontinued measurements of acrolein after May 6, 2016 due to the instability of 2-propenal in cylinders.

3.2.2 REGULATORY SETTING

3.2.2.1 Criteria Pollutants

Ambient air quality standards in California are the responsibility of, and have been established by, both the U.S. EPA and CARB. These standards have been set at concentrations, which provide margins of safety for the protection of public health and welfare. Federal and state air quality standards are presented in Table 3.2-1. The federal, state, and local air quality regulations are identified below in further detail.

3.2.2.1.1 Federal Regulations

The U.S. EPA is responsible for setting and enforcing the National Ambient Air Quality Standards for oxidants (ozone), CO, NO_2, SO_2, PM10, PM2.5, and lead. The U.S. EPA has jurisdiction over emissions sources that are under the authority of the federal government including aircraft, locomotives, and emissions sources outside state waters (Outer Continental Shelf). The U.S. EPA also establishes emission standards for vehicles sold in states other than California. Automobiles sold in California must meet the stricter emission requirements of the CARB.

The Clean Air Act (CAA) Amendments of 1990 give the U.S. EPA additional authority to require states to reduce emissions of ozone precursors and particulate matter in non-attainment areas. The amendments set attainment deadlines based on the severity of problems. At the state level, CARB has traditionally established state ambient air quality standards, maintained oversight authority in air quality planning, developed programs for reducing emissions from motor vehicles, developed air emission inventories, collected air quality and meteorological data, and approved state implementation plans. At a local level, California's air districts, including the Air District, are responsible for overseeing stationary source emissions, approving permits, maintaining emission inventories, maintaining air quality stations, overseeing agricultural burning permits, and reviewing air quality-related sections of environmental documents required by CEQA.

Other federal regulations applicable to the Bay Area include Title III of the Clean Air Act, which regulates toxic air contaminants. Title V of the Act establishes a federal permit program for large stationary emission sources. The U.S. EPA also has authority over the Prevention of Significant Deterioration (PSD) program.

3.2.2.1.2 California Regulations

CARB, which became part of the California Environmental Protection Agency in 1991, is responsible for ensuring implementation of the California Clean Air Act and federal Clean Air Act, and for regulating emissions from consumer products and motor vehicles. CARB has established California Ambient Air Quality Standards for all pollutants for which the federal government has established National Ambient Air Quality Standards and also has standards for sulfates, visibility, hydrogen sulfide and vinyl chloride. Federal and state air quality standards are presented in Table 3.2-1 under Air Quality Environmental Setting. California standards are generally more stringent than the National Ambient Air Quality Standards. CARB has established emission standards for vehicles sold in California and for various types of combustion equipment. CARB also sets fuel specifications to reduce vehicular emissions.

CARB released the Proposed 2016 State Strategy for the State Implementation Strategy on May 17, 2016. The measures contained in the State SIP Strategy reflect a combination of state actions, petitions for federal action, and actions for deployment of cleaner technologies in all sectors. CARB's proposed state SIP Strategy includes control measures for on-road vehicles, locomotives, ocean going vessels, and off-road equipment that are aimed at helping all districts in California to comply with federal and state ambient air quality standards.

California gasoline specifications are governed by both state and federal agencies. During the past two decades, federal and state agencies have imposed numerous requirements on the production and sale of gasoline in California. CARB adopted the Reformulated Gasoline Phase III regulations in 1999, which required, among other things, that California phase out the use of MTBE in gasoline. The CARB Reformulated Gasoline Phase III regulations have been amended several times (the most recent amendments were adopted in 2013) since the original adoption by CARB.

The California Clean Air Act (AB2595) mandates achievement of the maximum degree of emission reductions possible from vehicular and other mobile sources in order to attain the state ambient air quality standards by the earliest practical date.

3.2.2.1.3 Air District Regulations

The California Legislature created the Air District in 1955. The Air District is responsible for regulating stationary sources of air pollution in the nine counties that surround San Francisco Bay: Alameda, Contra Costa, Marin, Napa, San Francisco, San Mateo, Santa Clara, southwestern Solano, and southern Sonoma counties. The District is governed by a 24-member Board of Directors composed of publicly-elected officials apportioned according to the population of the represented counties. The Board has the authority to develop and enforce regulations for the control of air pollution within its jurisdiction. The District is responsible for implementing emissions standards and other requirements of federal and state laws. Numerous regulations have been developed by the District to control emissions sources within its jurisdiction. It is also responsible for developing air quality planning documents required by both federal and state laws.

Bay Area facilities are subject to various air quality regulations that have been adopted by the Air District, CARB and U.S. EPA. These rules contain standards that are expressed in a variety of forms to ensure that emissions are effectively controlled including:

- Requiring the use of specific emission control strategies or equipment (e.g., the use of floating roof tanks for VOC emissions);
- Requiring that emissions generated by a source be controlled by at least a specified percentage (e.g., 95 percent control of VOC emissions from pressure relief devices);
- Requiring that emissions from a source not exceed specific concentration levels (e.g., 100 parts per million (ppm) by volume of VOC for equipment leaks, unless those leaks are repaired within a specific timeframe; 250 ppm by volume SO_2 in exhaust gases from sulfur recovery units; 1,000 ppm by volume SO_2 in exhaust gases from catalytic cracking units);
- Requiring that emissions not exceed certain quantities for a given amount of material processed or fuel used at a source (e.g., 0.033 pounds NOx per million BTU of heat input, on a refinery-wide basis, for boilers, process heaters, and steam generators);
- Requiring that emissions be controlled sufficient to not result in off property air concentrations above specified levels (e.g., 0.03 ppm by volume of hydrogen sulfide (H_2S) in the ambient air);
- Requiring that emissions from a source not exceed specified opacity levels based on visible emissions observations (e.g., no more than 3 minutes in any hour in which emissions are as dark or darker than No. 1 on the Ringelmann chart); and
- Requiring that emissions be minimized by the use of all feasible prevention measures (e.g., flaring prohibited unless it is in accordance with an approved Flare Minimization Plan).
- Requiring that emissions of non-methane organic compounds and methane from the waste decomposition process at solid waste disposal sites be limited.
- Requiring emission limits on precursor organic compounds from valves and flanges as chemical plants.
- Requiring emission limits of nitrogen oxides, particulate matter, and toxic air contaminants from the manufacture of Portland cement.
- Requiring the limitation of emissions of organic compounds from gasoline dispensing facilities.
- Requiring the development of and compliance with Emissions Minimations Plans designed to minimize the fugitive emissions of particulate matter and odorous substances from foundries and forges.

Air quality rules generally do not expressly limit mass emissions (e.g., pounds per year of any particular regulated air pollutant) from affected equipment unless that equipment was constructed or modified after March 7, 1979 and subject to the Air District's New Source Review (NSR) rule. All Bay Area refineries have "grandfathered" emission sources that were not subject to NSR but are generally regulated by equipment specific Air District regulations. As a result, none of these facilities have an explicit stated overall mass emission limits that apply to the entire refinery. However, as a practical matter, the refinery's mass emissions are limited by a combination of permit limits, capacity and design of grandfathered sources, and the mechanical layout and design of the refinery. Mass emissions of relevant regulated air pollutants from Bay Area refineries are closely monitored, and these mass emissions have generally been substantially reduced over the past several decades. In recent years, emissions of criteria pollutants and greenhouse gasses from refineries have been stable or decreasing.

Air pollutant emissions from Bay Area petroleum refineries have been regulated for over 50 years, with most of the rules and regulations being adopted following enactment of the 1970 Clean Air Act amendments. The Air District has the primary responsibility to regulate "stationary sources" of air pollution in the Bay Area, and the Air District has adopted many rules and regulations that apply to petroleum refineries.

3.2.2.2 Toxic Air Contaminants

The Air District uses three approaches to reduce TAC emissions and to reduce the health impacts resulting from TAC emissions: 1) Specific rules and regulations; 2) Pre-construction review; and, 3) the Air Toxics Hot Spots Program.

3.2.2.2.1 Rules and Regulations

Many of the TACs emitted by petroleum refineries are also criteria pollutants. For example, benzene and formaldehyde are precursor organic compounds, while arsenic and cadmium can be found in particulate matter. Thus, many regulations that reduce criteria pollutant emissions from refineries will also have a co-benefit of reducing toxic air contaminant emissions. In addition, the Air District implements U.S. EPA, CARB, and Air District rules that specifically target toxic air contaminant emissions from sources at petroleum refineries.

3.2.2.2.2 Preconstruction Review

The Air District's Regulation 2, Rule 5 is a preconstruction review requirement for new and modified sources of TACs implemented through the Air District's permitting process. This rule includes health impact thresholds, which require the use of the best available control technology for TAC emissions (TBACT) for new or modified equipment, and health risk limits cannot be exceeded for any proposed project.

3.2.2.2.3 Air Toxics Hot Spots Program

The Air Toxic Hot Spots program, or AB2588 Program, is a statewide program implemented by each individual air district pursuant to the Air Toxic Hot Spots Act of 1987 (Health and Safety Code Section 44300 et. seq.). The Air District uses standardized procedures to identify health impacts resulting from industrial and commercial facilities and encourage risk reductions at these facilities. Health impacts are expressed in terms of cancer risk and non-cancer hazard index.

Under this program, the Air District uses a prioritization process to identify facilities that warrant further review. This prioritization process uses toxic emissions data, health effects values for TACs, and Air District approved calculation procedures to determine a cancer risk prioritization score and a non-cancer prioritization score for each site. The District updates the prioritization scores annually based on the most recent toxic emissions inventory data for the facility. Facilities that have a cancer risk prioritization score greater than 10 or a non-cancer prioritization greater than 1 must undergo further review. If emission inventory refinements and other screening procedures indicate that prioritizations scores remain above the thresholds, the Air District will require that the facility perform a comprehensive site-wide HRA.

An Air Toxic Hot Spots Act HRA estimates the health impacts from a site due to stationary source emissions. Hot Spots Act HRAs must be conducted in accordance with statewide HRA Guidelines adopted by OEHHA that include health effects values for each TAC and establish the procedures to follow for modeling TAC transport, calculating public exposure, and estimating the resulting health impacts. OEHHA periodically reviews and updates these HRA Guidelines through a scientific review panel and public comment process. The HRA Guidelines were approved in 2003, but OEHHA proposed major revisions to these HRA Guidelines in June 2014. These proposed HRA Guidelines were adopted in March 2015.

In 1990, the Air District Board of Directors adopted the current risk management thresholds pursuant to the Air Toxic "Hot Spots" Act of 1987. These risk management thresholds, which are summarized in Table 3.2-6 below, set health impact levels that require sites to take further action, such as conducting periodic public notifications about the site's health impacts and implementing mandatory risk reduction measures.

TABLE 3.2-6

Summary of Bay Area Air Toxics Hot Spots Program Risk Management Thresholds

Requirement	Site Wide Cancer Risk	Site Wide Non-Cancer Hazard Index
Public Notification	Greater than 10 in one million	Greater than 1
Mandatory Risk Reduction	Greater than 100 in one million	Greater than 10

3.2.2.3 Accidental Release Regulation

Petroleum refineries are also subject to regulatory programs that are intended to prevent accidental releases of substances. The primary programs of this type are based on requirements in the 1990 Clean Air Act amendments as follows: (1) the Process Safety Management (PSM) program, which focuses on protecting workers, and which is administered by the U.S. Occupational Safety & Health Administration (OSHA), and (2) the Accidental Release Prevention program (commonly referred to as the Risk Management Program, or RMP), which focuses on protecting the public and the environment, and which is administered by U.S. EPA. Bay Area refineries are subject to Cal/OSHA's PSM program, which is very similar to the federal OSHA program, but with certain more stringent State provisions. Bay Area refineries are subject to the California Accidental Release Prevention (CalARP) Program, which is very similar to U.S. EPA's RMP program, but with certain more stringent State provisions. In addition, Contra Costa County and the City of Richmond have both adopted an Industrial Safety Ordinance (ISO). These ISO's are very similar to CalARP requirements, but with certain more stringent local provisions. Accidental release prevention programs in California are implemented and enforced by local Administering Agencies, which in the case of the Bay Area refineries are Solano County (for the Valero Refining Company) and Contra Costa County (for the four other Bay Area refineries).

A partial list of the air pollution rules and regulations that the Air District implements and enforces at Bay Area facilities (e.g. refineries, cement manufacturing plants, power plants, chemical plants, landfills, sewer treatment facilities, etc.) follows:

- Air District Regulation 1: General Provisions and Definitions
- Air District Regulation 2, Rule 1: Permits, General Requirements
- Air District Regulation 2, Rule 2: New Source Review
- Air District Regulation 2, Rule 5: New Source Review of Toxic Air Contaminants
- Air District Regulation 2, Rule 6: Major Facility Review (Title V)
- Air District Regulation 6, Rule 1: Particulate Matter, General Requirements
- Air District Regulation 6, Rule 2: Miscellaneous Operations
- Air District Regulation 8, Rule 5: Storage of Organic Liquids
- Air District Regulation 8, Rule 6: Terminals and Bulk Plants
- Air District Regulation 8, Rule 7: Gasoline Dispensing Facilities
- Air District Regulation 8, Rule 8: Wastewater (Oil-Water) Separators
- Air District Regulation 8, Rule 9: Vacuum Producing Systems
- Air District Regulation 8, Rule 10: Process Vessel Depressurization
- Air District Regulation 8, Rule 18: Equipment Leaks
- Air District Regulation 8, Rule 22: Valves and Flanges at Chemical Plants
- Air District Regulation 8, Rule 28: Episodic Releases from Pressure Relief Devices at Petroleum Refineries and Chemical Plants
- Air District Regulation 8, Rule 33: Gasoline Bulk Terminals and Gasoline Delivery Vehicles
- Air District Regulation 8, Rule 34: Solid Waste Disposal Sites
- Air District Regulation 8, Rule 37, Natural Gas and Crude Oil Production Facilities
- Air District Regulation 8, Rule 39: Gasoline Bulk Terminals and Gasoline Delivery Vehicles
- Air District Regulation 8, Rule 44: Marine Vessel Loading Terminals
- Air District Regulation 9, Rule 1: Sulfur Dioxide
- Air District Regulation 9, Rule 2: Hydrogen Sulfide
- Air District Regulation 9, Rule 7: Nitrogen Oxides and Carbon Monoxide from Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process

HeatersAir District Regulation 9, Rule 8: Nitrogen Oxides and Carbon Monoxide from Stationary Internal Combustion Engines
- Air District Regulation 9, Rule 9: Nitrogen Oxides and Carbon Monoxide from Stationary Gas Turbines
- Air District Regulation 9, Rule 10: Nitrogen Oxides and Carbon Monoxide from Boilers, Steam Generators and Process Heaters in Petroleum Refineries
- Air District Regulation 9, Rule 11: Nitrogen Oxides And Carbon Monoxide from Utility Electric Power Generating Boilers
- Air District Regulation 9, Rule 13: Nitrogen Oxides, Particulate Matter, and Toxic Air Contaminants from Portland Cement Manufacturing
- Air District Regulation 11, Rule 1: Lead
- Air District Regulation 11, Rule 8: Hexavalent Chromium
- Air District Regulation 12, Rule 11: Flare Monitoring at Petroleum Refineries
- Air District Regulation 12, Rule 12: Flares at Petroleum Refineries
- Air District Regulation 12, Rule 13: Foundry and Forging Operations
- 40 CFR Part 63, Subpart CC: Petroleum Refineries (NESHAP)
- 40 CFR Part 63, Subpart UUU: Petroleum Refineries: Catalytic Cracking, Catalytic Reforming, and Sulfur Plant Units (NESHAP)
- 40 CFR Part 61, Subpart FF: Benzene Waste Operations (NESHAP)
- 40 CFR Part 60, Subpart J: Standards of Performance for Petroleum Refineries (NSPS)
- State Airborne Toxic Control Measure for Stationary Compression Ignition (Diesel) Engines (ATCM)

3.2.3 SIGNIFICANCE CRITERIA

3.2.3.1 Construction Emissions

Regarding construction emissions, the Air District’s 1999 Thresholds of Significance did not identify specific significance thresholds for construction emissions. Rather the analysis required that certain control measures be implemented and, if implemented, the air pollutant impacts would be less than significant. The construction emissions identified in the 2010 CEQA Guidelines would be more conservative as they provide a specific threshold number above which impacts would be considered significant (see Table 3.2-7). Therefore, the 2010 CEQA Guidelines will be used in the current air quality analysis for construction emissions.

TABLE 3.2-7

Thresholds of Significance for Construction-Related Criteria Air Pollutants and Precursors

Pollutant/Precursor	Daily Average Emissions (lbs/day)
ROG	54
NOx	54
PM10	82*
PM2.5	54*
PM10/ PM2.5 Fugitive Dust	Best Management Practices

*Applies to construction exhaust emissions only.
Source: BAAQMD, 2010

3.2.3.2 Operational Emissions

The District's CEQA Guidelines have been developed to assist local jurisdictions and lead agencies in complying with the requirements of CEQA regarding potentially adverse impacts to air quality. The District first developed CEQA guidelines, which included significance thresholds for use by lead agencies, in 1999 (BAAQMD, 1999). On June 2, 2010, the Bay Area Air Quality Management District's Board of Directors unanimously adopted thresholds of significance to assist in the review of projects under the California Environmental Quality Act. These thresholds are designed to establish the level at which the District believed air pollution emissions would cause significant environmental impacts under CEQA and were posted on the Air District's website and included in the Air District's updated CEQA Guidelines (BAAQMD, 2010).

The Air District's 2010 CEQA Thresholds have been the subject of legal challenges which are still on-going. In light of the legal challenges, the significance threshold for the current EIR could be the significance thresholds developed in 1999. These "original" significance thresholds limited emissions for project operations to 15 tons per year or 80 pounds per day of reactive organic gases (ROG), NOx and PM10.

Alternatively, the revised 2010 CEQA Guidelines could also be used. The revised CEQA Guidelines (BAAQMD, 2010) established thresholds for regional plans as well as project-specific thresholds on both an annual basis and a daily basis. The most recently available BAAQMD draft CEQA guidelines established emission thresholds for specific projects, general plans, and regional plans. An air quality rule does not fall neatly into any of these categories. Air Quality rules are typically regional in nature, as opposed to general plans, community plans and regional plans. In addition, air quality rules are usually specific to particular source types and particular pollutants. The Air Quality Plan threshold of "no net increase in emissions" is appropriate for Air Quality Plans because they include a mix of several control measures with individual trade-offs. For example, one control measure may result in combustion of methane to reduce greenhouse gas emissions, while increasing criteria pollutant emissions by a small amount. Those increases from the methane measure would be offset by decreases from other measures focused on reducing criteria pollutants. In a particular rule development effort, there may not be opportunities to make these trade-offs.

The 2010 project level stationary source thresholds are identified in Table 3.2-8. These thresholds are based on significant impact levels developed by the U.S. EPA as providing a significant contribution to regional non-attainment areas under the CAA. The Air District is planning to develop significance thresholds specifically for rules. Until that effort is complete and in order to provide a conservative air quality analysis, the thresholds recommended in the revised 2010 CEQA Guidelines (BAAQMD, 2010) will be used in the current air quality impacts analysis as they provide a more conservative analysis (lower thresholds) than the 1999 CEQA Guidelines.

TABLE 3.2-8

Thresholds of Significance for Operation-Related Criteria Air Pollutants and Precursors

Pollutant/Precursor	Daily Average Emissions (lbs/day)	Maximum Annual Emissions (tons/year)
ROG	54	10
NOx	54	10
PM10	82	15
PM2.5	54	10

*Source: BAAQMD, 2010

3.2.4 ENVIRONMENTAL IMPACTS

~~Chapter 2 identifies the main types of industrial facilities and their emission sources that would most likely be subject to the risk reduction requirements of Rule 11-18. Similarly,~~ Chapter 2 identifies types of refinery equipment that tend to be the largest sources of emissions that would be subject to Rule 12-16 and that have the greatest potential to contribute to potential exceedances of the facility-wide emissions limits for GHGs, PM2.5, PM10, NOx, and SO_2 emissions. Chapter 2 also identifies air pollution control technologies that would most likely to be installed on the equipment at affected facilities subject to ~~either Rule 11-18 or~~ Rule 12-16 that may require future emissions control.

It is expected that the direct effects of ~~either~~ the rule would be reductions in TAC or criteria pollutant emissions. However, construction equipment and activities to install air pollution control equipment has the potential to generate secondary air quality impacts, primarily from exhaust emissions. Further, air pollution control equipment that reduces one or more regulated pollutants has the potential to generate adverse secondary air quality impacts from other sources such as mobile sources or from the air pollution control equipment. For example, some types of air pollution control equipment that use caustic as part of the control process, have the potential to generate emissions of the caustic material that may be considered a TAC.

Potential secondary air quality impacts from construction activities and equipment for ~~both Rule 11-18 and~~ Rule 12-16 are analyzed first. ~~It is assumed in the construction analysis that similar types of construction equipment would be used to install air pollution control equipment regardless of which rule is ultimately adopted.~~ The analysis identifies construction air quality impacts from air pollution control equipment that could be installed to comply with pollution control requirements under the rule ~~both rules~~ (e.g., baghouse, diesel oxidation catalyst, wet gas scrubber, ~~etc.). Other types of air pollution control equipment would be installed only under Rule 11-18 (e.g., thermal oxidizer, carbon adsorption unit, etc.) or only under Rule 12-16 (e.g.,~~ SCR, SOx Oxidation Catalyst, etc.). As a result, the analysis of construction air quality impacts includes a range of control technologies that could be installed ~~if either proposed rule is adopted and an analysis of air pollution control technologies that could be installed only under Rule 11-18 or only under Rule 12-16. A discussion then follows comparing construction air quality impacts for each rule individually and if both rules are adopted~~. Construction and operation air quality impacts are identified and provided in the following subsections.

3.2.4.1 Potential Criteria Pollutant Impacts During Construction

Because ~~there are a wide variety of TACs with different physical or chemical characteristics, different types of control technologies may need to be installed, as necessary, at affected facilities to reduce risk levels to those proposed in Rule 11-18. Similarly, because~~ Rule 12-16 would regulate several different pollutants, GHGs, NOx, SO_2, PM10, PM2.5, different types of control technologies may need to be installed at affected refineries and associated facilities, as necessary, to comply with the annual facility-wide emission limits. The potential secondary adverse air quality impacts from control equipment identified in Chapter 2 that may be installed to comply with ~~either Rule 11-18 or~~ Rule 12-16 have been analyzed in the following subsections.

According to the Staff Report, ~~for the proposed rules, Rule 11-18 has the potential to affect hundreds of facilities, including data centers, petroleum refineries, a cement kiln, gasoline dispensing facilities, etc., while~~ Rule 12-16 would regulate five refineries and three associated facilities. ~~Without further analysis of the health risks from facilities that would be subject to Rule 11-18, it is unclear which facilities would be subject to risk reduction requirements or precisely what types of TAC control equipment would be installed. With regard to Rule 12-16, it~~It is not currently known whether any affected facilities would exceed the annual facility-wide emissions limits for the regulated pollutants. Similarly, if the annual facility-wide emissions for GHGs, PM2.5, PM10, NOx, and SO_2 are exceeded it is not known whether operators would limit operations or, alternatively, what types of GHG and criteria pollutant emissions control devices would be installed.

In spite of the uncertainties identified above, the analysis of construction air quality impacts identifies the most likely emissions sources that could contribute to non-compliance with

~~either~~ the rule, along with the most appropriate types of air pollution control equipment that would contribute to bringing the affected facility or equipment into compliance with ~~either rule's risk reduction or~~ annual facility-wide pollution control requirements. Likely control technologies are those that are considered to be BACT or BARCT for the emissions sources or are representative air pollution control technologies for the affected industrial sources. Once emissions sources and air pollution control technologies have been identified, the most likely types of construction equipment that would be used to install air pollution control equipment are then identified, construction scenarios are developed, and construction emission impacts are calculated.

Construction equipment associated with installing air pollution control technologies would result in VOC, NOx, SOx, CO, PM10, PM2.5, and GHG emissions, although the amount generated by specific types of equipment can vary greatly as shown in Table 3.2-9. As the table shows, different types of equipment can generate construction emissions in much different quantities depending on the type of equipment. For example, the estimated emissions of NOx range from of 0.1 pound per hour (lb/hr) of NOx for a forklift to 1.81 lbs/hr for scrapers. To provide a conservative construction air quality analysis and in the absence of information on the specific construction activities necessary to complete a construction project, a typical construction analysis assumes that, in the absences of specific information, all construction activities would occur for eight hours per day. This is considered a conservative assumption because workers may need to be briefed on daily activities, so construction may start later than their arrival times or the actual construction activities may not require eight hours to complete. However, for some construction projects, specific types of construction equipment and hours of operation have been developed using analyses prepared for other similar types of construction projects or using construction estimator guidelines used by construction contractors when bidding on jobs. As a result, under some construction scenarios hours of equipment operation may be more or less than eight hours.

A range of construction scenarios for installing various types of control equipment was identified to determine whether or not construction air quality impacts would exceed any applicable air quality significance thresholds. To provide a conservative analysis of potential construction air quality impacts, it is assumed that construction of one or more of the control technologies evaluated in the following subsections could overlap. The following subsections identify construction scenarios that may occur for several control technologies and are considered to be a representative range of construction activities and equipment used to install air pollution control equipment. Construction activities range from installing or retrofitting small-scale air pollution control equipment, which would require few pieces of construction equipment or hours of operation, to installing large-scale air pollution control technologies requiring large construction crews and a large number and types of construction equipment hours of operation. As shown in the following subsections, construction activities could result in substantial construction air quality impacts.

TABLE 3.2-9

Emission Factors Associated with Typical Construction Equipment(1)

Equipment Type	VOC (lb/hr)	CO (lb/hr)	NOx (lb/hr)	SOx (lb/hr)	PM (lb/hr)
Aerial Lifts- (Man Lifts)	0.00	0.17	0.10	0.00	0.00
Air Compressor	0.06	0.32	0.43	0.00	0.03
Bore/Drill Rig	0.04	0.50	0.57	0.00	0.02
Concrete Pump	0.01	0.04	0.05	0.00	0.00
Concrete Saw	0.07	0.40	0.43	0.00	0.03
Crane	0.06	0.41	0.80	0.00	0.04
Crane – Rough Terrain (120 hp)	0.07	0.40	0.42	0.00	0.02
Excavator	0.03	0.52	0.35	0.00	0.01
Forklift	0.02	0.22	0.19	0.00	0.01
Generator	0.05	0.28	0.41	0.00	0.22
Grader	0.07	0.58	0.93	0.00	0.04
Pavers	0.04	0.50	0.46	0.00	0.02
Paving Equipment	0.03	0.41	0.37	0.00	0.02
Plate Compactor	0.01	0.03	0.03	0.00	0.00
Rollers	0.03	0.39	0.27	0.00	0.02
Rough Terrain Forklifts	0.02	0.45	0.25	0.00	0.01
Rubber Tired Dozers	0.11	0.88	1.45	0.00	0.07
Rubber Tired Loaders	0.05	0.45	0.67	0.00	0.03
Scrapers	0.12	0.84	1.81	0.00	0.07
Skid Steer Loaders	0.01	0.21	0.16	0.00	0.01
Surfacing Equipment	0.03	0.42	0.52	0.00	0.02
Tractors/Loaders/Backhoes	0.03	0.36	0.31	0.00	0.02
Trenchers	0.05	0.44	0.41	0.00	0.03
Forklifts	0.02	0.22	0.19	0.00	0.01
Welders	0.04	0.19	0.21	0.00	0.02

(1) Emission Factors from Off-Road 2011. CO emissions from SCAQMD, 2006: http://www.aqmd.gov/ceqa/handbook/offroad/offroadEF07_25.xls.

3.2.4.1.1 Diesel ICEs~~ – Both Rules~~

Installing New Diesel ICEs: Diesel ICEs are often used to provide electricity in areas with no electricity, used as a backup source of electricity in the event of a power outage ~~from numerous types of facilities (e.g. hospitals),~~ or as a means of pumping liquids between different refinery equipment. Over the past several decades, emission limits for diesel ICEs have been established and modified to provide further control of exhaust pollutants. Initial emission limits for diesel ICEs were for engines referred to as Tier 1 ICEs. Diesel ICEs compliant with current emission limits are known as Tier 4 ICEs. Tier 4 ICEs are more efficient than Tier 1 ICEs and emit less pollutants. ~~Replacing Tier I ICEs with Tier 4 ICEs could occur under both rule scenarios.~~

Construction emissions associated with installing new ICEs would be minor and would involve the transport of the new ICE to the facility and the removal of the existing ICE which is expected to require two one-way truck trips. In this situation, construction would likely require one light-heavy-duty truck trip to deliver new ICEs and one trip to haul away the old ICE, a construction crew of five workers, one forklift, one generator set, one welder, and hand tools (Table 3.2-10). It is also expected that replacement would take one day or less.

TABLE 3.2-10

Construction Equipment Used to Install a Tier 4 ICE

Off- Road Equipment Type	Number	Daily Hours of Use
Forklift	1	2
Generator	1	4
Welder	1	4

Source: Based on SCAQMD, 2008. Assumptions modified for this analysis because it is assumed that one ICE unit would replace the existing ICE, instead of constructing the new ICE unit.

Table 3.2-11 shows construction emissions from installing one Tier 4 ICE. It is possible that more than one Tier 4 ICE could be installed on the same day ~~under both rule scenarios~~, resulting in overlapping construction emissions, which are also shown in Table 3.2-11. ~~It is assumed that more Tier 4 ICEs would be installed under Rule 11-18 because it regulates substantially more facilities than Rule 12-16 and, for a large number of these facilities, existing diesel ICEs are the main risk drivers. Therefore, based on the numbers of facilities subject to each rule and the uncertainties regarding the need to reduce health risks or reduce annual facility-wide emissions, the assumptions that 10 Tier 4 ICEs would be installed on the same day under Rule 11-18 and five would be installed under Rule 12-16 are likely conservative assumptions for the following reasons. According to the staff report for the proposed project, if adopted, Rule 11-18 would require preparation of new, or revisions to existing HRAs at affected facilities using OEHHA's 2015 HRA Guideline Revisions. Depending on the complexity of facility operations and the number of TAC emissions sources that would be subject to Rule 11-18, preparation of new or revisions to existing HRAs would likely be completed, evaluated, and approved over different time periods. However, because hundreds of facilities could be affected by implementing Rule 11-18 and many of these sources have ICEs, it is reasonable to assume that up to 10 ICEs would be replaced on a single day. Similarly, refineries~~Refineries and associated facilities that would be subject to Rule 12-16 may use a relatively large number of ICEs to provide electricity or pump product in remote areas of the facility that are not served by electricity. According to the Staff Report for the proposed project, the facility-wide emissions limits under Rule 12-16 do not currently appear to inhibit refining capacity, since typical annual average utilization is 80 – 87 percent, and the emissions limits appear to establish production capacity limits at approximately 89 – 93 percent utilization (BAAQMD, 2016b). If control of GHGs, NOx, SO_2, PM10, PM2.5 emissions at affected facilities in the future does become necessary, because operations can vary substantially between the affected facilities, the decision to replace existing Tier 1 ICEs with Tier 4 ICEs would not occur at the same time. Therefore, it is conservative ~~reasonable~~ to assume that ~~fewer ICEs,~~ up to five ICEs~~,~~ would be replaced on the same day.

TABLE 3.2-11

Construction Emissions from Installing a Tier 4 ICE

	Pollutant					
	ROG	**CO**	**NOx**	**SOx**	**PM10**	**PM2.5**
	ICE Replacement (lbs/day)					
Sub-total Off-road Construction Equipment	0.4	2.32	2.86	~~< 1.0~~ <0.01	0.98	0.98
Sub-total On-road (Worker + Haul Truck) (1)	0.48	2.41	1.91	<0.01	0.04	0.02
Total - 1 ICE Replacement	0.88	4.73	4.77	~~< 1.0~~ <0.01	1.02	1.00
~~Rule 11-18 - 10 Replacements~~	~~8.8~~	~~47.3~~	~~47.7~~	~~0.1~~	~~10.2~~	~~10.0~~
Rule 12-16 - 5 Replacements	4.4	23.7	23.8	~~0.0~~ <0.01	5.1	5.0
~~Both Rules - 15 Replacements~~	~~13.1~~	~~71.0~~	~~71.5~~	~~0.1~~	~~15.3~~	~~15.0~~
	~~ICE Replacement (tons/day)~~					
~~Both Rules - 15 Replacements~~	~~0.007~~	~~0.035~~	~~0.036~~	~~<0.000~~	~~0.008~~	~~0.008~~

(1) It is assumed that trucks are diesel light-heavy-duty trucks make two one-way trips of 20 miles. See Appendix B for calculation details.

Retrofitting Diesel ICEs: A potential alternative to installing a new diesel ICE is to retrofit an existing engine with a DPF or DOC. This scenario is potentially a less costly means of reducing diesel ICE emissions or may be preferable if only minor emission or risk reductions measures are necessary. Retrofitting an existing ICE with a DPF or DOC would require one forklift and a crew of four, primarily using hand tools, and would take one day to complete. One two-way truck trip would be necessary to deliver the control equipment to the affected facility. Construction air quality impacts from retrofitting diesel ICEs are shown in Table 3.2-12.

TABLE 3.2-12

Construction Emissions for Retrofitting Diesel ICEs

	Pollutants					
	ROG	**CO**	**NOx**	**SOx**	**PM10**	**PM2.5**
	ICE Retrofits (lbs/day)					
Sub-total Off-road Construction Equip	0.08	0.88	0.76	~~< 1.0~~ <0.01	0.04	0.04
Sub-total On-road (Worker + Haul Truck) (1)	0.19	0.40 0.44	1.30 1.60	~~0.00~~ <0.01	0.04	0.02
Total - 1 ICE Retrofit	0.27	1.28 1.32	2.06 2.36	~~0.00~~ <0.01	0.08	0.06
~~Rule 11-18 - 10 Retrofits~~	~~2.74~~	~~12.78~~	~~20.58~~	~~0.02~~	~~0.80~~	~~0.57~~
Rule 12-16 - 5 Retrofits	0.27	1.28	10.29	~~0.00~~ <0.01	0.08	0.06
~~Both Rules - 15 Retrofits~~	~~4.11~~	~~19.17~~	~~30.86~~	~~0.03~~	~~1.20~~	~~0.86~~
	~~**ICE Retrofits (tons/day)**~~					
~~Both Rules - 15 Retrofits~~	~~0.002~~	~~0.01~~	~~0.02~~	~~<0.000~~	~~<0.001~~	~~<0.001~~

Reference: SCAQMD 2008.

(1) It is assumed that trucks are diesel light-heavy-duty trucks and make two one-way trips of 20 miles and idle for 60 minutes. See Appendix B for calculation details.

It is possible that more than one diesel ICE could be retrofitted on the same day, resulting in overlapping construction emissions such as those shown in Table 3.2-12. Based on the uncertainties regarding the need to reduce health risks or reduce annual facility-wide emissions, the same assumptions for installing Tier 4 ICEs were used in this analysis of retrofitting diesel ICEs, that is, ~~10 ICEs would be retrofitted on the same day under Rule 11-18 and~~ five would be retrofitted under Rule 12-16. As indicated above, these assumptions are likely conservative assumptions for the following reasons. ~~According to the staff report, if adopted, Rule 11-18 would require preparation of new, or revisions to existing HRAs at affected facilities using OEHHA's 2015 HRA Guideline Revisions. Depending on the complexity of facility operations and the number of TAC emissions sources that would be subject to Rule 11-18, preparation of new or revisions to existing HRAs would likely be completed, evaluated, and approved over different time periods. However, because hundreds of facilities could be affected by implementing Rule 11-18 and many of these sources have ICEs, it is reasonable to assume that up to 10 diesel ICEs would be retrofitted on a single day.~~

~~Similarly, refineries~~Refineries and associated facilities that would be subject to Rule 12-16 may use many ICEs to provide electricity or pump product in remote areas of the facility that are not served by electricity. According to the Staff Report for the proposed project, the facility-wide emissions limits under Rule 12-16 do not currently appear to inhibit refining capacity, since typical annual average utilization is 80 – 87 percent, and the emissions limits appear to establish production capacity limits at approximately 89 – 93 percent utilization (BAAQMD, 2016b). If control of GHGs, NOx, SO_2, PM10, PM2.5

emissions at affected facilities in the future does become necessary, because operations can vary substantially between the affected facilities, the decision to retrofit existing diesel ICEs to comply with Tier 4 ICE standards would not occur at the same time. Therefore, it is conservative ~~reasonable~~ to assume that ~~fewer ICEs,~~ up to five ICEs~~,~~ would be retrofitted on the same day.

3.2.4.1.2 Installing a Wet Gas Scrubber ~~– Both Rules~~

In an evaluation of the various construction scenarios related to installing air pollution control equipment, it was concluded that installing a WGS would require more demolition and construction equipment and activities than installing other types of control technologies and, therefore, would provide a "worst-case" construction air quality analysis. Because of its large size, it is expected that physical construction activities associated with installing a WGS would occur over a 17-month period; one month to demolish any nearby existing equipment or structures and 16 months to construct the WGS, which would include: site preparation, assembly and installation of the unit and ancillary support equipment, and tying-in the new WGS to the affected equipment.

The following analysis of the construction impacts associated with installing a WGS is based on an EIR prepared for the installation of a WGS on an FCCU in southern California (SCAQMD, 2007). These construction emission estimates are appropriate for the construction air quality analysis for the proposed rules because they are based on the construction equipment for the use of one WGS on one refinery FCCU. ~~Both rules have the potential to require installation of a WGS because it can reduce TAC and criteria pollutant (SOx and PM2.5) emissions.~~ Regardless of the location of the construction activities, the amount or types of construction equipment and hours of operation, these parameters would not be expected to change compared to the 2007 analysis. The analysis uses a conservative assumption that equipment would operate for 10 hours per day because the 2007 project was on an aggressive installation schedule. The construction equipment that would most likely be required for the installation of a refinery WGS, for example, during a peak month is provided in Table 3.2-13.

Because of its large size, construction of one WGS would likely require as many as 175 construction workers and, using worst-case assumptions, it is assumed that constructing a WGS would require the use of one or more of the following types of construction equipment: backhoes, cranes, man lifts, forklift, front end loaders generators, diesel welding machines, jack hammers, a medium-duty flatbed truck, a medium-duty dump truck, and a cement mixer. Other sources of construction emissions could include: equipment delivery, on-site travel (would include fugitive dust associated with travel on paved roads, and fugitive dust associated with construction activities), and construction worker commute trips.

Depending on the size and types of equipment or structures that may need to be demolished, a worst-case assumption is that up to 50 construction workers would be required. Demolition activities are assumed to require the use of: one or more of the following types of equipment: crane, front-end loader, forklift, demolition hammer, water truck, and medium-duty flatbed truck. Other sources of demolition emissions could include haul truck trips to dispose of demolition debris, on-site travel (would include fugitive dust associated with travel on paved roads, fugitive dust associated with demolition activities), and construction worker commute trips.

TABLE 3.2-13

Estimated Peak Day Off-Road Construction Emissions from Installing One Refinery Wet Gas Scrubber

Off- Road Equipment Type	Number	Daily Hours of Use
Backhoe	1	10
Crane	2	10
Crane	1	10
Front End Loader	1	10
Man Lift	3	10
Forklift	2	10
Generator	1	10
Demolition Hammer	1	10
Welder	3	10

Reference: SCAQMD, 2007

Construction and demolition emission estimates for activities associated with installing one WGS are provided in Table 3.2-14. It is assumed that the proposed project has the potential to result in the construction of up to ~~three to five WGS units under Rule 11-18 or~~ three to five units under Rule 12-16. ~~If both rules are adopted, it is assumed that operators at affected facilities would install a single WGS to control both TAC and SOx emissions, which means that the assumption that three to five WGS units would be installed concurrently is still applicable.~~ Typically, construction activities occur sequentially, that is, demolition must be completed before construction activities begin. To provide a conservative analysis, demolition and construction activities are assumed to overlap. Construction estimates associated with constructing one WGS unit, three WGS units, and five WGS units are shown in Table 3.2-14.

~~The assumption that constructing three to five WGS units could occur under Rule 11-18 is likely a conservative assumptions for the following reasons. According to the staff report, if adopted, Rule 11-18 would require preparation of new, or revisions to existing HRAs at affected facilities using OEHHA's 2015 HRA Guideline Revisions. Depending on the complexity of facility operations and the number of TAC emissions sources, preparation of new, or revisions to existing HRAs would likely be completed, evaluated, and approved over different time periods. If it is determined that affected facilities exceed the health risk requirements in Rule 11-18 and a decision is made to install a WGS, then it would likely take months or years to provide engineering specifications, acquire financing, purchase and deliver the necessary equipment, complete Air District permit evaluations, and undergo any necessary environmental analyses.~~

TABLE 3.2-14

Estimated Construction Emissions for Wet Gas Scrubbers

ACTIVITY	CO	ROG	NOx	SOx	PM10	PM2.5
Construction Emissions from one WGS on Refinery Units[(1)] (lbs/day)						
Demolition for 1 WGS at Refinery[(1)]	36	6	28	<1	3	2
Construction Activities for 1 Refinery WGS[(1)]	67	17	84	<1	39	23
Total Construction Estimates for one WGS on Refinery Units (tons emitted during construction period)						
Demolition for 1 WGS at Refinery[(2)]	0.36	0.06	0.28	<0.1	0.03	0.02
Construction Activities for 1 WGS at Refinery[(3)]	8.04	2.04	10.08	<0.1	4.68	2.76
Total Construction Emissions per each WGS[(3)]	8.4	2.1	10.4	<0.1	4.7	2.8
Construction Emissions for 3 and 5 Large WGS (tons) on Refinery Units (tons emitted during construction period)						
Total Construction Emissions 3 WGS Units	25.2	6.3	31.2	<1	14.1	8.4
Total Construction Emissions 5 WGS Units	42	10.5	52	<1	23.5	14

(1) Reference: SCAQMD, 2007

(2) Demolition activities include off-road construction equipment and on-road mobile source emissions and are estimated to occur for one month (20 working days)

(3) Construction activities include off-road construction equipment and on-road mobile source emissions and are estimated to occur for a total of 16 months (20 working days per month), with 8 months at peak construction activities and 8 months at 50 percent of peak construction activities.

The assumption that three to five WGS units could be constructed at the same time under Rule 12-16 is considered to be a conservative assumption for the following reasons. According to the Staff Report for the proposed project, the facility-wide emissions limits do not currently appear to inhibit refining capacity, since typical annual average utilization is 80 – 87 percent, and the emissions limits appear to establish production capacity limits at approximately 89 – 93 percent utilization (BAAQMD, 2016b). That is, the annual emissions caps in Rule 12-16 appear to be consistent with the current maximum production capability of the refineries so additional control equipment is currently unnecessary. However, the trend in fuel consumption since 2012 has been toward increasing consumption. It is possible that in future years, refinery operators may want to increase refinery capacity within current permit limitations, so air pollution control equipment including WGS units may need to be installed. As noted in the paragraph above, from the concept stage to completing construction of a WGS could take months or years, which further reduces the probability of constructing three or more WGS units at the same time.

3.2.4.1.3 Installing a Selective Catalytic Reduction Unit ~~– Rule 12-16 Only~~

An analysis of construction emissions to install an SCR unit is included here because it ~~would apply only to Rule 12-16 and~~ is a large unit that would require substantial construction activities. SCR is typically considered to be BACT or BARCT to reduce NOx emissions from large industrial combustion sources. Combustion sources at affected facilities that could be retrofitted with SCR include refinery FCCUs, boilers, process heaters, or gas turbines. The construction period duration necessary for installing an SCR depends primarily on the type of equipment being retrofitted. For example, retrofitting a refinery FCCU with SCR would occur over approximately 12 to 13 months, require a total of 260 days of construction, and use a crew of 140 construction workers during peak construction periods. SCRs could also be retrofitted onto refinery boilers, process heaters, or gas turbines. However, such units are typically smaller compared to retrofitting an SCR onto an FCCU, so construction crews would be smaller and the overall duration of construction activities would be much shorter. Because retrofitting an SCR onto an FCCU would provide a more conservative analysis of construction air quality impacts than retrofitting an SCR onto refinery boilers, process heaters, or gas turbines, the following analysis focuses on quantifying construction emissions from retrofitting an SCR onto an FCCU.

The following analysis of the construction air quality impacts associated with installing SCRs on refinery FCCUs is based on an environmental analysis of the effects of further limiting NOx emissions at southern California refineries (SCAQMD, 2015a). These construction emission estimates are appropriate for the construction air quality analysis for Rule 12-16 because they are based on the construction equipment assumed to be associated with a permit application for the use of a SCR on refinery FCCUs. Regardless of the location of the construction activities, the amount or types of construction equipment and hours of operation, these parameters would not be expected to change. The construction equipment that would most likely be required for installing an SCR on one refinery FCCU during a peak month is provided in Table 3.2-15.

The construction emission estimates for activities associated with installing one SCR on a refinery FCCU are provided in Table 3.2-16. Major demolition activities are not expected to be necessary to install an SCR because these units are constructed directly next to or on to the emissions sources' exhaust stacks. It is possible that more than one SCR could be constructed at the same time resulting in overlapping construction emissions such as those shown in Table 3.2-16. Therefore, it is conservatively assumed here that Rule 12-16 has the potential to result in the construction of up to three SCR units on refinery FCCUs. Emission estimates for installing up to three SCR units on refinery FCCUs are also shown in Table 3.2-16. As noted above, retrofitting refinery boilers, process heaters, and gas turbines with SCRs would generate lower construction emissions than shown in Table 3.2-16 because the SCR units would be smaller in scale compared to those installed onto an FCCU.

TABLE 3.2-15

Estimated Peak Day Off-Road Construction Emissions from Installing One SCR on One FCCU

	FCCU SCR Unit	
Off- Road Equipment Type	**Number**	**Daily Hours of Use**
Air Compressor	1	8
Backhoe	1	8
Concrete Pump	1	2
Concrete Saw	1	2
Crane	2	10
Forklift	1	6
Generator	2	8
Man Lift	2	2
Plate Compactor	1	2
Welder	~~5~~ 2	8

Source: SCAQMD, 2015a

TABLE 3.2-16

Estimated Construction Emissions for an SCR Unit on A Refinery FCCU[(a)]

ACTIVITY	ROG	CO	NOx	SOx	PM10	PM2.5
Peak Construction Emissions One SCR Unit (lbs/day)						
Construction Activities for 1 FCCU SCR (1)	1.86	12.02	14.94	0	4.12	3.79
Total Construction On-road Vehicle Trips (2)	5.22	8.58	8.60	0.71	0.47	0.22
Total Construction emissions	7.08	20.60	23.54	0.71	4.59	4.01
Total Construction Emissions for One SCR Unit (tons emitted during construction period)						
Construction Activities for 1 FCCU SCR (1)	0.69	~~3.18~~ 2.01	~~3.75~~ 2.29	0.07	~~0.85~~ 0.45	~~0.76~~ 0.41
Total Construction Emissions for 3 SCR Units (tons emitted during construction period)						
Construction Activities for 3 FCCU SCR	2.07	~~9.54~~ 6.02	~~11.25~~ 6.88	0.21	~~2.55~~ 1.34	~~2.28~~ 1.23

Reference: SCAQMD 2015

(1) Construction activities are estimated to occur for a total of 12 months (20 working days per month), with 6 months at peak construction activities and 6 months at 50 percent of peak construction activities.

(2) Vehicle trip assumptions include average vehicle ridership of 1.0 and a trip length of 11 miles one way (CAPCOA, 2016).

It is possible that more than one SCR could be constructed at the same time. However, the assumption that up to three SCR units could be constructed at the same time to control NOx emissions from refinery FCCUs may be a conservative assumption for the following reasons. According to the Staff Report for the proposed project, the facility-wide emissions limits do not appear to inhibit refining capacity, since typical annual average utilization is 80 – 87 percent, and the emissions limits appear to establish production capacity limits at approximately 89 – 93 percent utilization (BAAQMD, 2016b). That is, the caps in Rule 12-16 appear to be consistent with the current maximum production capability of the refineries so additional control equipment is currently unnecessary. However, the trend in fuel consumption since 2012 has been toward increasing consumption. It is possible that in future years, refinery operators may want to increase refinery capacity within current permit limitations, so air pollution control equipment including SCR units may need to be installed. Finally, from concept to completing construction of an SCR unit could take months or years, which further reduces the probability of constructing three to multiple SCR units at the same time.

~~3.2.4.1.4 Installing a Carbon Adsorption Unit – Rule 11-18 Only~~

~~The most likely TAC emission sources that would be subject to Rule 11-18 and that could be controlled using carbon adsorption units are expected to be sewage treatment facilities because various stages of the sewage treatment process produce ROG emissions that may include TAC components. A survey of wastewater treatment facilities in the Bay Area indicated that there are at least 20 facilities ranging in size from a discharge rate of 0.1 to greater 30 million gallons per day (Pacific Institute, 2009)[2].~~

~~The construction analysis for installing a carbon adsorption unit is based on a construction emissions analysis from installing air pollution control equipment similar in size to a carbon adsorption unit because no actual carbon adsorption construction scenarios were identified. Construction parameters associated with installing a carbon adsorption unit would occur over a timeframe of approximately six to seven months, requiring a total of 130 days of construction and using a crew of 20 construction workers. Table 3.2-17 shows the types of construction equipment and their hours of operation anticipated to be need to install one carbon adsorption unit.~~

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[2] This number underestimates the total number of wastewater treatment facilities because it only refers to facilities that may be affected a 100-year coastal flood or a 1.4 meter rise in sea level. It does not include, for example, the three wastewater treatment facilities in the City of San Francisco. This information is provided only to show that a relatively large number of carbon adsorption units could be installed as a result of adopting Rule 11-18.

~~TABLE 3.2-17~~

~~Estimated Peak Day Off-Road Construction Emissions from Installing One Carbon Adsorption Unit~~

	~~Carbon Adsorption Unit~~	
~~Off- Road Equipment Type~~	~~Number~~	~~Daily Hours of Use~~
~~Backhoe~~	~~1~~	~~4~~
~~Rough Terrane Crane~~	~~1~~	~~8~~
~~Welder~~	~~2~~	~~8~~
~~Air Compressor~~	~~1~~	~~4~~
~~Plate Compactor~~	~~1~~	~~4~~
~~Forklift~~	~~1~~	~~3~~
~~Concrete Pump~~	~~1~~	~~2~~
~~Concrete Saw~~	~~1~~	~~2~~
~~Generator~~	~~1~~	~~8~~
~~Man Lift~~	~~1~~	~~2~~

~~Construction emission estimates for activities associated with installing one carbon adsorption unit are provided in Table 3.2-18. Major demolition activities are not expected to be necessary to install a carbon adsorption unit because the units are relatively compact. It is possible that more than one carbon adsorption unit could be constructed at the same time resulting in overlapping construction emissions such as those shown in Table 3.2-18. Therefore, it is conservatively assumed here that Rule 11-18 has the potential to result in the construction of up to five carbon adsorption units at sewage treatment facilities. Emission estimates of installing up to five carbon adsorption units are also shown in Table 3.2-18.~~

~~The assumption that construction of five carbon adsorption units could occur under Rule 11-18 is likely a conservative for the following reasons. According to the staff report, if adopted, Rule 11-18 would require preparation of new, or revisions to existing HRAs at affected facilities using OEHHA's 2015 HRA Guideline Revisions. Depending on the complexity of facility operations and the number of TAC emissions sources, preparation of new, or revisions to existing HRAs would likely be completed, evaluated, and approved over different time periods. If it is determined that affected facilities, primarily sewage treatment facilities, exceed the health risk requirements in Rule 11-18 and a decision is made to install a carbon adsorption unit, then it would likely take months, possibly years, to provide engineering specifications, acquire financing, purchase and deliver the necessary equipment, complete Air District permit evaluations, and undergo any necessary environmental analyses.~~

~~TABLE 3.2-18~~

~~Estimated Construction Emissions for a Carbon Adsorption Unit~~

~~ACTIVITY~~	~~ROG~~	~~CO~~	~~NOx~~	~~SOx~~	~~PM10~~	~~PM2.5~~
~~Peak Construction Emissions One Carbon Adsorption Unit (lbs/day)~~						
~~Subtotal Construction Activities for 1 Unit~~	~~2.34~~	~~9.76~~	~~14.85~~	~~0.00~~	~~2.14~~	~~1.97~~
~~Sub-total On-road (Worker + Haul Truck)~~ ~~(1)~~	~~0.93~~	~~1.08~~	~~1.68~~	~~0.01~~	~~0.08~~	~~0.04~~
~~Total Construction emissions~~	~~3.27~~	~~10.84~~	~~16.53~~	~~0.01~~	~~2.22~~	~~2.01~~
~~Total Construction Emissions for One Carbon Adsorption Unit (tons emitted during construction period)~~						
~~Construction Activities for 1 Unit~~ ~~(2)~~	~~0.16~~	~~0.53~~	~~0.81~~	~~0.00~~	~~0.11~~	~~0.10~~
~~Total Construction Emissions for 5 Carbon Adsorption Units (tons emitted during construction period)~~						
~~Construction Activities for 5 Units~~	~~0.80~~	~~2.64~~	~~4.03~~	~~0.00~~	~~0.54~~	~~0.49~~

~~(1) Vehicle trip assumptions include average vehicle ridership of 1.0 and a trip length of 11 miles one way (CAPCOA, 2016).~~

~~(2) Construction activities are estimated to occur for a total of 6 to 7 months (130 working days total) with a 20-person work crew.~~

3.2.4.1.4 Summary of Construction Emission Impacts

As demonstrated in the subsections above, construction and installation of some types of air pollution control technologies would not necessarily be expected to result in significant adverse construction air quality impacts. ~~For example, replacing existing diesel ICEs with Tier 4 ICEs or retrofitting diesel ICEs with DPFs of DOCs could occur if either Rule 11-18 or Rule 12-16 is adopted. For either control scenario, emissions would be relatively low and would only be expected to occur on a single day. As shown in Tables 3.2-11 and 3.2-12, construction air quality impacts from installing new, or retrofitting existing diesel ICEs would be greater under Rule 11-18 than under Rule 12-16 because substantially more industrial facilities that have diesel ICEs would be regulated under Rule 11-18. Construction air quality impacts would be greater still if more than one diesel ICE is replaced or retrofitted on the same day or both rules are adopted.~~

As summarized in Table 3.2-17, ~~Tables 3.2-19~~ ~~and 3.2-20, Rule 11-18 and~~ Rule 12-16~~,~~ ~~respectively,~~ could produce substantial construction air quality impacts if larger types of air pollution control equipment are installed. This impact would be compounded if more than one piece of air pollution control equipment is installed on the same day. ~~Again, because Rule 11-18 would potentially regulate a substantially greater number of industrial sources, it would create greater air quality impacts than Rule 12-16.~~

~~TABLE 3.2-19~~

~~Worst-Case Construction Emissions Under Rule 11-18~~

~~ACTIVITY~~	~~ROG~~	~~CO~~	~~NOx~~	~~SOx~~	~~PM10~~	~~PM2.5~~
~~Peak Construction Emissions Per Unit Under Rule 11-18 (lbs/day)~~						
~~Diesel ICE Replacements 1 ICEs~~	~~0.88~~	~~4.73~~	~~4.77~~	~~0.005~~	~~1.02~~	~~1.00~~
~~Diesel ICE Retrofits 1 ICEs~~	~~0.27~~	~~1.28~~	~~2.06~~	~~<0.01~~	~~0.08~~	~~0.06~~
~~Total for 1 WGS (1)~~	~~17~~	~~67~~	~~84~~	~~<1.0~~	~~39~~	~~23~~
~~Total for 1 Carbon Adsorption~~	~~3.27~~	~~10.84~~	~~16.53~~	~~0.01~~	~~2.22~~	~~2.01~~
~~Total Potential Overlapping Emissions~~	~~21.4~~	~~83.9~~	~~107.4~~	~~0.0~~	~~42.3~~	~~26.1~~
~~Significance Thresholds~~	~~54~~	~~None~~	~~54~~	~~None~~	~~82~~	~~54~~
~~Significant?~~	~~No~~	~~--~~	**~~Yes~~**	~~--~~	~~No~~	~~No~~
~~Total Construction Emissions for 1 Unit for Both Types of Control Equipment (tons emitted during construction period)~~						
~~Total Construction Emissions for 1 WGS~~	~~2.1~~	~~8.4~~	~~10.4~~	~~<0.1~~	~~4.7~~	~~2.8~~
~~Total for 1 Carbon Adsorption Unit~~	~~0.16~~	~~0.53~~	~~0.81~~	~~0.00~~	~~0.11~~	~~0.10~~
~~Total Potential Overlapping Emissions~~	~~2.26~~	~~8.97~~	~~11.21~~	~~<1.0~~	~~4.81~~	~~3.1~~
~~Total Construction Emissions for 5 Units for Both Types of Control Equipment (tons emitted during construction period)~~						
~~Total for 5 WGS Units~~	~~10.5~~	~~42~~	~~52~~	~~<1.0~~	~~23.5~~	~~14~~
~~Total for 5 Carbon Adsorption Unit~~	~~0.8~~	~~2.7~~	~~4.0~~	~~<1.0~~	~~0.5~~	~~0.5~~
~~Total Potential Overlapping Emissions~~	~~11.3~~	~~44.7~~	~~56.0~~	~~<1.0~~	~~24.0~~	~~14.5~~

~~(1) Reference: SCAQMD 2007~~

TABLE 3.2-~~20~~17

Worst-Case Construction Emissions Under Rule 12-16

ACTIVITY	ROG	CO	NOx	SOx	PM10	PM2.5
Peak Construction Emissions Per Unit Under Rule 12-16 (lbs/day)						
Diesel ICE Replacements 1 ICEs	0.88	4.73	4.77	~~0.005~~ <0.01	1.02	1.00
Diesel ICE Retrofits 1 ICE	0.27	~~1.28~~ 1.32	~~2.06~~ 2.36	<0.01	0.08	0.06
Total Construction Emissions for 1 WGS (1)	17	67	84	~~<1.0~~ <0.01	39	23
Total Construction Emissions for 1 SCR	7.08	20.60	23.54	0.71	4.59	4.01
Total Potential Overlapping Emissions	25.23	~~93.61~~ 92.29	~~114.37~~ 112.01	0.72	44.69	28.07
Significance Thresholds	54	None	54	None	82	54
Significant?	No	--	**Yes**	--	No	No
Total Construction Emissions for 1 Unit for Both Types of Control Equipment (tons emitted during construction period)						
Total for 1 WGS	2.1	8.4	10.4	<0.1	4.7	2.8
Total for 1 SCR	0.69	~~3.18~~ 2.01	~~3.75~~ 2.29	0.07	~~0.85~~ 0.45	~~0.76~~ 0.41
Total Potential Overlapping Emissions	2.79	~~11.58~~ 10.41	~~14.15~~ 12.69	<0.1	~~5.55~~ 5.15	~~3.56~~ 3.21

Total Construction Emissions for 5 WGS and 3 SCR Units
(tons emitted during construction period)

Total for 5 WGS Units	10.5	42	52	<1.0	23.5	14
Total for 3 SCRs	2.07	~~9.54~~ 6.02	~~11.25~~ 6.88	0.21	~~2.55~~ 1.34	~~2.28~~ 1.23
Total Potential Overlapping Emissions	12.6	~~51.5~~ 48.02	~~63.3~~ 58.88	<1.0	~~24.1~~ 24.84	~~16.3~~ 15.23

(1) Reference: SCAQMD 2007

Conclusion: Based on the construction emissions shown ~~for each rule~~ in Table 3.2-17 ~~Tables 3.2-19 and 3.2-20~~, it is concluded that NOx construction air quality impacts would be significant ~~under either rule scenario and substantially more significant if both rules are adopted~~. ROG, PM10, and PM2.5 construction emissions are less than the applicable significance threshold and, therefore, are concluded to be less than significant. Construction emissions, however, are temporary as construction emissions would cease following completion of construction activities.

3.2.4.2 Potential Criteria Pollutant Impacts During Operation

The net effect of implementing ~~Rule 11-18 is to reduce cancer and non-cancer health risks by reducing TAC emissions from regulated~~ Rule 12-16 would be limiting ~~reduce~~ NOx, SO_2, PM10, and PM2.5, emissions from five refineries and three associated facilities, thus, contributing to improvements to local air quality. However, some control technologies have the potential to generate secondary or indirect air quality impacts as part of the control process. Table 3.2-~~21~~18 lists all the identified air pollution control technologies that may be used to comply with future regulatory requirements under ~~either Rule 11-18,~~ Rule 12-16~~, or both~~, as well as potential secondary or indirect operational air quality impacts associated with some types of air pollution control technologies. Those air pollution control technologies in Table 3.2-~~21~~18 where no direct or indirect operational air quality impacts were identified are not discussed further. The remaining air pollution control technologies that have the potential to generate secondary or indirect operational air quality impacts, will be evaluated further in the following subsections.

The following analyses of potential operational secondary air quality impacts from the proposed project include the following assumption; it is assumed that no additional employees would be needed to operate any new or modified air pollution control equipment, so the existing work force at each affected facility is expected to be sufficient. As such, no workers' commute trip emissions are anticipated for the operation of the new or modified air pollution control equipment.

TABLE 3.2-~~21~~18

Potential Operational Air Quality Impacts from Installing Air Pollution Control Equipment

Applicable Rule	Potential Control Technology	Air Quality Impacts	Analyzed Further?
~~11-18 &~~ 12-16	Baghouse with HEPA Filters	None identified (IFC, 2007 & STAPPA /ALAPCO, 2000)	**No**
~~11-18~~	~~Carbon Adsorption~~	~~Combustion emissions from regenerating spent carbon~~	~~**Yes**~~
12-16	Compressor	Minor emissions increase in some phases, overall VOC & TAC reduction (SCAQMD, 2013)	**No**
12-16	Cyclone	None identified STAPPA/ALAPCO, 2000)	**No**
~~11-18 &~~ 12-16	Diesel Oxidation Catalyst	None identified by any sources during technology review	**No**
~~11-18 &~~ 12-16	Diesel Particulate Filter	Slight NO_2 increase from regenerating filter	**Yes**
12-16	Electrostatic Precipitator (Wet and Dry)	None identified (STAPPA/ALAPCO, 2000)	**No**
12-16	Fuel Gas Treatment (Additive to Existing Amine System)	Slight increase in TAC (caustic) & H_2S emissions in one phase, overall TAC & H_2S reductions (Perry, 2015)	**No**
12-16	Fuel Gas Treatment (Merox)	Slight increase in H_2S emissions in one phase, overall H_2S reductions (Perry, 2015)	**No**
12-16	LoTOx™	Some ozone "slip", but reaction is rapid, impact is minor (CARB, 2005)	**No**
~~11-18 &~~ 12-16	New Diesel ICEs	None identified by any sources during technology review	**No**
12-16	Selective Catalytic Reduction	Ammonia slip emissions, minor indirect mobile source emission increases	**Yes**

Applicable Rule	Potential Control Technology	Air Quality Impacts	Analyzed Further?
12-16	Selective Oxidation Catalyst	Slight NOx increase (EPA, 1982)	**No**
~~11-18~~	~~Steam Ejector Technology~~	~~Minor emissions increase in one phase, overall VOC & TAC reduction (SCAQMD, 2013)~~	~~**No**~~
12-16	SOx Reducing Additive	None identified (Bin, H. and Min-yuan, H., 2000)	**No**
~~11-18~~	~~Thermal Oxidizer~~	~~Potential increase in combustion emissions~~	~~**Yes**~~
12-16	Ultracat	Ammonia slip emissions, minor indirect mobile source emission increases	**Yes**
~~11-18 &~~ 12-16	Wet Gas Scrubber	Slight increase in TAC, minor indirect mobile source emission increases	**Yes**

~~3.2.4.2.1 Carbon Adsorption – Rule 11-18 Only~~

~~Carbon adsorption equipment was identified as one of the control technologies that could be used to reduce cancer and non-cancer health risks by reducing TAC emissions at sewage treatment facilities. The initial control efficiency of carbon adsorption equipment is extremely high, but as the activated carbon becomes saturated with organic material over time, control efficiency drops until breakthrough occurs. When breakthrough occurs, the saturated carbon must be removed and either disposed of or regenerated and the solvent recovered, or removed and destroyed.~~

~~Typically, the spent carbon is regenerated by raising the temperature of the carbon, evacuating the bed, or both. A regenerant, either steam or a noncondensible gas, is heated and injected into the carbon bed to desorb the organic materials. This procedure is usually performed daily, but may be done more or less frequently, depending on the capacity of the control unit and the concentration of the VOC being collected. The resulting heated organic mixture is vented to a condenser, where the organic material is separated from the regenerant by gravity or distillation, and recycled or disposed of properly.~~

~~Regenerating spent carbon typically requires a combustion source using natural gas as the combustion fuel to heat the regenerant and/or to heat the carbon beds. Only 15 percent of the carbon bed volume collects toxic VOC emissions and a typical carbon bed is sized to reduce VOC emissions by approximately 55 pounds per day. Based on these two~~

~~characteristics, a typical carbon bed size is approximately 400 pounds (55/0.15 = 400). The projected natural gas fuel use is 5.5 standard cubic feet (scf) of natural gas per pound of carbon and the carbon bed is assumed to be regenerated four times per day (SCAQMD, 2016). Based on the assumption in Subsection 3.2.4.1.4 that up to five carbon adsorption units could be installed under Rule 11-18, the amount of natural gas required per day is estimated to be 0.044 million cubic feet (MMcf) [(400 lbs C) x (5.5 scf/lb C per regen) x (4 regen/day) x (5 Carbon Adsorption Units) = 0.044 MMcf/day]. The projected criteria pollutant emissions from the combustion equipment used to regenerate spent carbon are shown in Table 3.2-22.~~

~~TABLE 3.2-22~~

~~Potential Operational Air Quality Impacts from Regenerating Spent Carbon from Carbon Adsorption Units~~

	~~Pollutant~~					
	~~ROG~~	~~CO~~	~~NOx~~	~~SOx~~	~~PM10~~	~~PM2.5(1)~~
~~AER Emission Factor (lb/MMcf)(2)~~	~~7~~	~~35~~	~~130~~	~~0.83~~	~~7.5~~	~~7.5~~
~~Natural Gas Consumed (MMcf/day)~~	~~0.062~~	~~0.062~~	~~0.062~~	~~0.062~~	~~0.062~~	~~0.062~~
~~Total Emissions 1 unit (lb/day)~~	~~0.43~~	~~2.17~~	~~8.06~~	~~0.05~~	~~0.47~~	~~0.47~~
~~Total Emissions 1 unit (tons/year)~~	~~0.08~~	~~0.4~~	~~1.47~~	~~0.01~~	~~0.09~~	~~0.09~~
~~Total Emissions 5 units (lb/day)~~	~~2.15~~	~~10.85~~	~~40.30~~	~~0.25~~	~~2.35~~	~~2.35~~
~~Total Emissions 5 units (tons/year)~~	~~0.40~~	~~2.0~~	~~7.35~~	~~0.05~~	~~0.45~~	~~0.45~~

~~(1) The PM2.5 fraction of PM10 for natural gas combustion is assumed to be 100%.~~

~~(2) Default emission factors for natural gas combustion for external combustion sources. SCAQMD Annual Emissions Reporting.~~

~~As shown in Table 3.2-22, regenerating spent carbon used in carbon adsorption units would result in a net increase in criteria pollutant emissions. Since it is expected that carbon adsorption units would operate every day at sewage treatment facilities, daily and annual emissions from all units would be additive.~~

~~3.2.4.2.2~~3.2.4.2.1 Diesel Particulate Filters ~~– Both Rules~~

Use of DPFs may result in a slight increase in directly emitted NOx during the regeneration of passive DPFs. In response to this undesirable effect, DPF manufacturers have improved their efforts to overcome increased NOx production by using other catalytic formulations or lowering the precious metal content of the traps. One DPF manufacturer has recently developed an improved DPF system capable of reducing PM emissions by at least 85 percent while also limiting NOx emissions to 25 percent compared to NOx emissions without a DPF. Limited test data for newer designs indicate that DPFs can reduce NOx emissions by six to ten percent, so overall there may be a small, but less than significant increase in NOx emissions and with some models there may be a net reduction in NOx emissions from operation of the filter. The net air quality effect of using DPFs is concluded to be neutral.

~~3.2.4.2.3 Thermal Oxidizers – Rule 11-18 Only~~

~~It is expected that thermal oxidizers would be used to control TAC emissions primarily at landfills and sewage treatment facilities. It is unlikely that landfills, also referred to as solid waste disposal sites, would install additional control such as thermal oxidizers because they are currently stringently regulated by Rule 8-34. Similarly, it is unlikely refinery operators would have to install additional controls for their wastewater collection systems because they are stringently regulated pursuant to Rule 8-8. Therefore, it is assumed that installation of thermal oxidizers would occur at sewage treatment facilities.~~

~~To quantify air quality impacts from the operation of thermal oxidizers, it is assumed they operate using two million British thermal unit (mmBtu) natural gas burners. The operational emissions associated with operation of one thermal oxidizer are summarized in Table 3.2-23.~~

~~TABLE 3.2-23~~

~~Potential Operational Air Quality Impacts from Thermal Oxidizers~~

~~Pollutant~~	~~ROG~~	~~CO(1)~~	~~NOx (2)~~	~~SOx~~	~~PM10~~	~~PM2.5~~
~~Emission factor in lb/mmscf (3)~~	~~7.00~~	~~0.30~~	~~1.04~~	~~0.60~~	~~7.50~~	~~7.50~~
~~Heater Duty mmbtu/hr~~	~~3.00~~	~~3.00~~	~~3.00~~	~~3.00~~	~~3.00~~	~~3.00~~
~~Operational time hr/day~~	~~8.0~~	~~8.0~~	~~8.0~~	~~8.0~~	~~8.0~~	~~8.0~~
~~Emissions lb/day~~	~~0.48~~	~~21.31~~	~~2.63~~	~~0.04~~	~~0.51~~	~~0.51~~
~~Emissions tons/yr~~	~~0.09~~	~~3.89~~	~~0.48~~	~~0.01~~	~~0.09~~	~~0.09~~
~~5 Facilities Emissions lb/day~~	~~2.40~~	~~106.55~~	~~13.15~~	~~0.20~~	~~2.55~~	~~2.55~~
~~5 Facilities Emissions tons/yr~~	~~0.45~~	~~19.45~~	~~2.40~~	~~0.05~~	~~0.45~~	~~0.45~~

~~Source: Detailed calculations can be found in BAAQMD, 2016, Appendix A.~~

~~(1) Based on 400 ppm~~

~~(2) Based on 30 ppm~~

~~(3) Default emission factors for natural gas combustion for external combustion sources. SCAQMD Annual Emissions Reporting.~~

~~As shown in Table 3.2-23, operating thermal oxidizers would create criteria pollutant emissions during operation. Since it is expected that thermal oxidizers would operate every day at sewage treatment facilities, daily and annual emissions from all units would be additive.~~

~~3.2.4.2.4~~3.2.4.2.2 Wet Gas Scrubbers ~~– Both Rules~~

Although the main effect of installing air pollution control equipment is reducing emissions, some types of control equipment require delivery of materials that are a necessary part of the pollution control process. For example, WGS operations require a delivery of fresh catalyst and caustic solution on a daily basis. Therefore, indirect emissions occur from trucks delivering supplies (i.e., fresh catalyst and caustic solution to refill the storage tanks) on a regular basis is expected. Similarly, SCR units require delivery of a reducing agent, typically ammonia, to reduce NOx emissions.

Depending on the size and configuration of the WGS, the sodium hydroxide (NaOH) caustic solution used in the WGS would likely need to be delivered one time per week or a little over 50 additional delivery truck trips per year per unit. For example, catalyst and caustic solutions are typically used in relatively small amounts per day. The use of NaOH (50 percent solution, by weight) caustic in a WGS unit would most likely occur at facilities that already use and store NAOH caustic for other purposes, typically in one 10,000-gallon storage tank. Otherwise, the facility operator would need to construct a new NAOH caustic storage tank and ancillary piping and other associated equipment. Since ~~neither Rule 11-18 nor~~ Rule 12-16 ~~specifically identifies~~ does not specify emission sources that would need to be controlled, it is assumed for this analysis that a WGS would be built that could be supplied by the same type of caustic solution that is already used onsite for other purposes so construction of a new NaOH storage tank would not be required. Similarly, depending on the size and configuration of the SCR unit, the number of truck trips to deliver ammonia for use in SCRs would be approximately one time every nine days or approximately 40 truck trips per year per unit.

Truck trips transporting the catalyst/caustic or ammonia solutions would occur relatively infrequently and it is not likely that all affected facilities would reduce SO_2, PM, or TAC emissions using a WGS or SCR, respectively. Further, a single truck's emissions while delivering caustic solutions from San Jose to Benicia[3], for example, would be very low, a few pounds per day at most. As shown in Table 3.2-~~24~~19, indirect mobile source emissions from transporting the catalyst/caustic or ammonia solutions would be low.

TABLE 3.2-~~24~~19

Delivery Truck Emissions

Material	Number of Truck Trips	Estimated Trip Length (round-trip miles)	Pollutants					
			~~CO~~ ROG	~~ROG~~ CO	NOx	SOx	PM10	PM2.5
Peak Operational Emissions Per Facility (lbs/day)								
Caustic/Catalyst for WGS Unit	2	120	0.06	0.26	1.84	0.02	~~0.31~~ 0.04	0.02
Ammonia for SCR	2	100	0.05	0.22	1.58	0.004	0.031	0.017
Total			0.11	0.48	3.42	0.024	~~0.341~~ 0.071	0.037
Peak Operational Emissions Per Facility (Tons/year)								
~~Caustic/catalyst for WGS Unit~~	~~104~~	~~120~~	~~0.032~~	~~0.14~~	~~0.96~~	~~0.00~~	~~0.160~~	~~0.011~~
~~Ammonia for SCR~~	~~80~~	~~100~~	~~0.00~~	~~0.01~~	~~0.06~~	~~0.00~~	~~0.00~~	~~0.00~~

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[3] Review of caustic suppliers located a chemical supplier in San Jose. The haul truck trip from San Jose to the Valero Refining Company in Benicia would likely represent a conservative trip length assumption because trip lengths to all other affected facilities would be shorter.

Caustic/catalyst for WGS Unit	104	120	<0.01	0.01	0.10	<0.01	<0.01	<0.01
Ammonia for SCR	80	100	<0.01	0.01	0.06	<0.01	<0.01	<0.01
Peak Operational Emissions Multiple Facilities (Tons/year)								
~~Caustic/catalyst for 5 WGS Units~~	~~520~~	~~120~~	~~0.16~~	~~0.68~~	~~4.78~~	~~0.005~~	~~0.802~~	~~0.054~~
~~Ammonia for 3 SCRs~~	~~240~~	~~100~~	~~0.01~~	~~0.03~~	~~0.19~~	~~0.00~~	~~0.00~~	~~0.00~~
~~Total~~			~~0.17~~	~~0.71~~	~~4.97~~	~~0.005~~	~~0.802~~	~~0.054~~
Caustic/catalyst for 5 WGS Units	520	120	0.02	0.07	0.48	<0.01	0.01	<0.01
Ammonia for 3 SCRs	240	100	0.01	0.03	0.19	<0.01	<0.01	<0.01
Total			0.03	0.10	0.67	<0.01	<0.01	<0.01

Source: BAAQMD, 2017

~~3.2.4.2.5~~3.2.4.2.3 Conclusion

~~As can be seen in Table 3.2-25, adopting Rule 11-18 would not produce operational emissions that exceed either the Air District's daily criteria pollutant significance thresholds, but annual NOx emissions would exceed the annual NOx emission significance threshold. The thermal oxidizer is the main contributor to NOx emission impacts. ROG, PM10 and PM2.5 emissions would be less than the applicable significance threshold and, therefore, are concluded to be less than significant.~~

~~TABLE 3.2-25~~

~~Worst-Case Operational Emissions Under Rule 11-18~~

~~ACTIVITY~~	~~ROG~~	~~CO~~	~~NOx~~	~~SOx~~	~~PM10~~	~~PM2.5~~
~~Peak Operational Emissions Per Facility Under Rule 11-18 (lbs/day)~~						
~~Regenerating Spent Carbon~~	~~0.43~~	~~2.17~~	~~8.06~~	~~0.05~~	~~0.47~~	~~0.47~~
~~Caustic/Catalyst for WGS Unit Truck Trips~~	~~0.06~~	~~0.26~~	~~1.84~~	~~0.02~~	~~0.31~~	~~0.02~~
~~Thermal Oxidizer~~	~~0.48~~	~~21.31~~	~~2.63~~	~~0.04~~	~~0.51~~	~~0.51~~
~~Total Potential Overlapping Emissions~~	~~0.97~~	~~23.74~~	~~12.53~~	~~0.11~~	~~1.29~~	~~1.00~~
~~Significance Thresholds~~	~~54~~	~~None~~	~~54~~	~~None~~	~~82~~	~~54~~
~~Significant?~~	~~No~~	~~--~~	~~No~~	~~--~~	~~No~~	~~No~~
~~Annual Operational Emissions for 1 Facility (tons per year)~~						
~~Regenerating Spent Carbon~~	~~0.08~~	~~0.4~~	~~1.47~~	~~0.01~~	~~0.09~~	~~0.09~~
~~Caustic/Catalyst for WGS Unit Truck Trips~~	~~0.032~~	~~0.14~~	~~0.96~~	~~0.00~~	~~0.160~~	~~0.011~~
~~Thermal Oxidizer~~	~~0.45~~	~~19.45~~	~~2.40~~	~~0.05~~	~~0.45~~	~~0.45~~
~~Total Potential Overlapping Emissions~~	~~0.54~~	~~19.89~~	~~4.16~~	~~0.06~~	~~0.579~~	~~0.551~~
~~Worst-case Annual Operational Emissions for Multiple Facilities (tons per year)~~						
~~Regenerating Spent Carbon~~	~~0.40~~	~~2.0~~	~~7.35~~	~~0.05~~	~~0.45~~	~~0.45~~
~~Caustic/Catalyst for WGS 5 Units Truck Trips~~	~~0.16~~	~~0.68~~	~~4.78~~	~~0.005~~	~~0.802~~	~~0.054~~
~~Thermal Oxidizer~~	~~0.45~~	~~19.45~~	~~2.40~~	~~0.05~~	~~0.45~~	~~0.45~~
~~Total Potential Overlapping Emissions~~	~~0.9~~	~~21.65~~	~~11.2~~	~~0.101~~	~~1.094~~	~~0.954~~
~~Significance Thresholds tons/year~~	~~10~~	~~None~~	~~10~~	~~None~~	~~15~~	~~10~~
~~Significant?~~	~~No~~	~~--~~	~~Yes~~	~~--~~	~~No~~	~~No~~

As indicated in Table 3.2-~~26~~20, neither the daily nor annual criteria pollutant significance thresholds for NOx, ROG, PM10, or PM2.5 would be exceeded from adopting Rule 12-16.

Therefore, Rule 12-16 would be less than significant for all criteria pollutants for both daily and annual emissions.

~~As can be seen in Table 3.2-27, if both rules are adopted, operational emissions would not exceed the Air District's daily criteria pollutant significance thresholds, but annual NOx emissions would exceed the Air District's annual significance threshold for NOx. Therefore, operational NOx emissions would be significant. ROG, PM10 and PM2.5 emissions would be less than the applicable significance threshold and, therefore, are concluded to be less than significant.~~

It should be noted that in addition to the estimated emission increases associated with the operation of new air pollution control equipment under ~~either Rule 11-18 or~~ Rule 12-16, reduction in air emissions would also be expected. Some of those reductions would be large, for example, a WGS would be expected to result in large SOx and PM10/PM2.5 emissions, as applicable. However, it is not possible to estimate those emission reductions at this point until the sources that will be controlled are known, the type of air pollution control device has been identified, appropriate engineering analyses have been completed and so forth. Nonetheless the potential emission increases are expected to be either wholly or partially offset with emission decreases.

TABLE 3.2-~~26~~20
Worst-Case Operational Emissions Under Rule 12-16

ACTIVITY	ROG	CO	NOx	SOx	PM10	PM2.5
Peak Operational Emissions Per Facility Under Rule 12-16 (lbs/day)						
~~Caustic/Catalyst for WGS Unit Truck Trips~~	~~0.02~~	~~0.08~~	~~0.56~~	~~0.00~~	~~0.07~~	~~0.02~~
~~Ammonia for SCR Truck Trips~~	~~0.05~~	~~0.22~~	~~1.58~~	~~0.004~~	~~0.031~~	~~0.017~~
~~Total Potential Overlapping Emissions~~	~~0.9~~	~~21.65~~	~~11.2~~	~~0.101~~	~~1.094~~	~~0.954~~
Caustic/Catalyst for WGS Unit Truck Trips	0.61	2.61	18.37	0.19	0.37	0.21
Ammonia for SCR Truck Trips	0.32	1.34	9.49	0.02	0.19	0.10
Total Potential Overlapping Emissions	0.93	3.95	27.86	0.21	0.56	0.31
Significance Thresholds lbs/day	54	None	54	None	82	54
Significant?	No	--	No	--	No	No
Annual Operational Emissions for 1 Facility (tons per year)						
~~Caustic/Catalyst for WGS Unit~~	~~0.010~~	~~0.04~~	~~0.29~~	~~0.00~~	~~0.039~~	~~0.011~~
~~Ammonia for SCR~~	~~0.00~~	~~0.01~~	~~0.06~~	~~0.00~~	~~0.00~~	~~0.00~~
~~Total Potential Overlapping Emissions~~	~~0.07~~	~~0.3~~	~~2.14~~	~~0.004~~	~~0.102~~	~~0.037~~
Caustic/Catalyst for WGS Unit	<0.01	0.01	0.10	<0.01	<0.01	<0.01
Ammonia for SCR	<0.01	0.01	0.06	<0.01	<0.01	<0.01
Total Potential Overlapping Emissions	<0.01	0.02	0.16	<0.01	<0.01	<0.01
Worst-case Annual Operational Emissions for Multiple Facilities (tons per year)						
~~Caustic/Catalyst for WGS 5Units~~	~~0.188~~	~~0.047~~	~~0.494~~	~~<1.0~~	~~0.064~~	~~<1.0~~
~~Ammonia for SCR 3 Units~~	~~0.01~~	~~0.03~~	~~0.19~~	~~0.00~~	~~0.00~~	~~0.00~~
~~Total Potential Overlapping Emissions~~	~~0.198~~	~~0.077~~	~~0.684~~	~~0~~	~~0.064~~	~~0~~
Caustic/Catalyst for WGS 5Units	0.02	0.07	0.48	<0.01	0.01	<0.01
Ammonia for SCR 3 Units	0.01	0.03	0.19	<0.01	<0.01	<0.01
Total Potential Overlapping Emissions	0.03	0.10	0.67	<0.01	0.01	<0.01
Significance Thresholds tons/year	10	None	10	None	15	10
Significant?	No	--	No	--	No	No

~~TABLE 3.2-27~~

~~Worst-Case Operational Emissions Under Both Rules~~

~~ACTIVITY~~	~~ROG~~	~~CO~~	~~NOx~~	~~SOx~~	~~PM10~~	~~PM2.5~~
~~Peak Operational Emissions Both Rules (lbs/day)~~						
~~Total Emissions from Rule 11-18~~	~~0.97~~	~~23.74~~	~~12.53~~	~~0.11~~	~~1.29~~	~~1.00~~
~~Total Emissions from Rule 12-16~~	~~0.9~~	~~21.65~~	~~11.2~~	~~0.10~~	~~1.09~~	~~0.95~~
~~Total Potential Overlapping Emissions~~	~~1.83~~	~~45.21~~	~~22.45~~	~~0.19~~	~~2.14~~	~~1.95~~
~~Significance Thresholds lbs/day~~	~~54~~	~~None~~	~~54~~	~~None~~	~~82~~	~~54~~
~~Significant?~~	~~No~~	~~--~~	~~No~~	~~--~~	~~No~~	~~No~~
~~Worst-case Annual Operational Emissions for Both Rules (tons per year)~~						
~~Total Emissions from Rule 11-18~~	~~0.9~~	~~21.65~~	~~11.2~~	~~0.101~~	~~1.094~~	~~0.954~~
~~Total Emissions from Rule 12-16~~	~~0.198~~	~~0.077~~	~~0.684~~	~~0~~	~~0.064~~	~~0~~
~~Total Potential Overlapping Emissions~~	~~1.10~~	~~21.73~~	~~11.88~~	~~0.10~~	~~1.16~~	~~0.95~~
~~Significance Thresholds lbs/day~~	~~10~~	~~None~~	~~10~~	~~None~~	~~15~~	~~10~~
~~Significant?~~	~~No~~	~~--~~	~~Yes~~	~~--~~	~~No~~	~~No~~

3.2.4.3 Potential Toxic Air Contaminant Impacts

~~3.2.4.2.1~~3.2.4.3.1 Selective Catalytic Reduction & Ultracat ~~(Rule 12-16 Only)~~

Unreacted ammonia emissions generated from SCR units are referred to as ammonia slip. BACT for ammonia slip is limited to five parts per million (ppm) and enforced by a specific permit condition. Modeling has been performed that shows the concentration of ammonia at a receptor located 25 meters from a stack would be much less than one percent of the concentration at the release from the exit of the stack (SCAQMD, 2015b)[4]. Thus, the peak concentration of ammonia at a receptor located 25 meters from a stack is calculated by assuming a dispersion of one percent. While ammonia does not have an OEHHA approved cancer potency value, it does have non-carcinogenic chronic (200 µg/m3) and acute (3,200 µg/m3) reference exposure levels (RELs). Table 3.2-~~28~~21 summarizes the calculated non-carcinogenic chronic and acute hazard indices for ammonia and compared these values to the respective significance thresholds; both were shown to be less than significant.

Even if multiple SCRs are installed at one refinery facility under Rule 12-16, the locations of all the stacks would not be situated in the same place within the affected facility's property. As such, even with multiple SCR installations, non- cancer health risks would be less than the acute and chronic hazard indices.

TABLE 3.2-~~28~~21

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[4] It is expected that concentrations at 25 meters in the Bay Area would be comparable or less than in southern California because the different meteorological conditions in southern California compared to the Bay Area.

Ammonia Slip Calculation

Ammonia Slip Conc. at the Exit of the Stack, ppm(1)	Dispersion Factor(2)	Molecular Weight, g/mol	Peak Conc. at a Receptor 25 m from the Stack, ug/m3	Acute REL, ug/m3	Chronic REL, ug/m3	Acute Hazard Index(3)	Chronic Hazard Index(3)
5	0.01	17.03	35	3,200	200	0.01	0.17

(1) Assumes ammonia slip is limited to five ppm by permitting.
(2) Assumes that the concentration at a receptor 25 m from a stack would be much less than one percent of the concentration at the release from the exist of the stack (SCAQMD, 2015b). The dispersion factor is based on local meteorology.
(3) Hazard index = conc. at receptor 25 m from stack, ug/m3/REL, ug/m3

3.2.4.3.2 Wet Gas Scrubbers and Flue Gas Treatment

To comply with the ~~risk or~~ emission reduction requirements of ~~Rule 11-18 or~~ Rule 12-16, ~~respectively,~~ WGS units with flue gas treatment (FGT) may be installed on FCCUs. For example, caustic is used in the operation of a WGS and some FGT applications. It is assumed for this analysis that refineries already using caustic would install a WGS or FGT application that uses the same type of caustic that is already in use at the refinery. Otherwise, a new storage tank with ancillary piping and equipment would need to be constructed.

There are several types of caustic solutions that can be used in WGS operations, but NaOH (50 percent solution, by weight) is the one most commonly used. NaOH is a TAC that is a non-cancerous, but an acutely hazardous substance. NaOH emissions typically occur as a result of filling loss and the working loss of each NaOH tank, resulting in relatively low NaOH emissions. Because it is assumed that refinery operators would opt to use the same type of caustic that they are currently using for other purposes, there would likely be a small incremental increase in risk because of the increased throughput of caustic through the existing storage tanks. However, because NaOH is typically diluted and used in small quantities, the combined filling loss and working loss would be small. In addition, any NaOH storage tanks would likely be located in the interior areas of a refinery, so the distance to the nearest sensitive receptive would likely be far enough away that substantial dispersion of any NaOH emission would occur. Table 3.2-~~29~~22 shows the level of NaOH working losses at a receptor located 25 meters from the unit.

TABLE 3.2-~~29~~22

NaOH Working Losses

Projected Increase in NaOH Demand (tons/day)	A: Hourly NaOH (as PM10) Filling Loss (lb/hr)	B: Hourly NaOH (as PM10) Working Loss (lb/hr)	A + B = Total Hourly NaOH (as PM10) Losses (lb/hr)	NaOH Acute Level at 25 meters (lb/hr)
3.37	7.60E-04	2.28E-03	2.28E-03	2.28E-05

See Appendix B for calculation methodology.

As indicated in Table 3.2-~~29~~22, the rate of NaOH working loss emissions would be relatively low for any WGS unit. Since it is likely that only one tank would be used to store the NaOH solution at each affected facility, working loss concentrations would not overlap. As such, even with multiple NaOH storage tanks, it is not expected that working loss emissions would exceed the acute and chronic hazard indices.

Further, there is an alternative to using NaOH as the caustic solution, sodium carbonate (Na_2CO_3) which is commonly known as soda ash, a non-toxic, non-cancerous, and nonhazardous substance. This caustic does not have the potential to generate significant adverse TAC emission impacts. For these reasons, it is unlikely that NaOH emissions would create significant adverse acute or chronic hazard impacts to any nearby sensitive receptors.

It should be noted that although there may be secondary TAC emissions associated with the operation of new air pollution control equipment under ~~either Rule 11-18 or~~ Rule 12-16, an overall reduction in TAC emissions would be expected. However, it is not possible to estimate those emission reductions at this point until the sources that will be controlled are known, the type of air pollution control device has been identified, appropriate engineering analyses have been completed and so forth. Nonetheless, air pollution control equipment installed to control TAC emissions as a result of the proposed rule is expected to result in a reduction in TAC emissions from affected facilities.

3.2.4.4 Conclusion

~~3.2.4.4.1 Rule 11-18~~

~~Based on the evaluation of those air pollution control technologies that would most likely be the used to reduce SO_2, PM2.5, and TAC emissions from affected facilities if required pursuant to Rule 11-18, construction and secondary operational air quality impacts from the proposed project could generate NOx emissions that exceed the Air District's construction and operations emission thresholds. Therefore, construction and operational air quality impacts are concluded to be significant for NOx emissions. ROG, PM10 and PM2.5 emissions would be less than the applicable significance threshold and, therefore, are concluded to be less than significant for both construction and operation.~~

~~3.2.4.4.2 Rule 12-16~~

Based on the evaluation of those air pollution control technologies that would most likely be used if required pursuant to Rule 12-16, operational air quality impacts from the proposed project would not exceed the Air District's operations emission thresholds for NOx, ROG, PM10 or PM2.5. However, construction air quality impacts from the proposed project could generate NOx emissions that exceed the Air District's construction emission thresholds. Therefore, construction air quality impacts are concluded to be significant for NOx emissions, but less than significant for ROG, PM10 and PM2.5.

~~3.2.4.4.3 Both Rules~~

~~Based on the evaluation of those air pollution control technologies that would most likely be the used to reduce SO_2, PM2.5, and TAC emissions from affected facilities if both rules were adopted, construction and secondary operational air quality impacts from the proposed project could generate NOx emissions that exceed the Air District's construction and operations emission thresholds. Therefore, construction and operational air quality impacts are concluded to be significant for NOx emissions. ROG, PM10 and PM2.5 emissions would be less than the applicable significance threshold and, therefore, are concluded to be less than significant for both construction and operation.~~

3.2.5 MITIGATION MEASURES

3.2.5.1 Construction Mitigation Measures

The proposed project is expected to have significant adverse air quality impacts during the construction phase. Therefore, the following mitigation measures will be imposed on future projects comprised of installing air pollution control equipment to reduce emissions associated with construction activities

A-1 Develop a Construction Emission Management Plan for each affected facility to minimize emissions from vehicles including, but not limited to: consolidating truck deliveries; scheduling deliveries to avoid peak hour traffic conditions; describing truck routing; describing deliveries including logging delivery times; describing entry/exit points; identifying locations of parking; identifying construction schedule; and prohibiting truck idling in excess of five consecutive minutes or another timeframe as allowed by the California Code of Regulations, Title 13 §2485 - CARB's Airborne Toxic Control Measure to Limit Diesel-Fueled Commercial Motor Vehicle Idling. The Construction Emission Management Plan shall be submitted to Air District staff for approval prior to the start of construction. At a minimum, the Construction Emission Management Plan would include the following types of mitigation measures.

On-Road Mobile Sources:

A-2 The Emission Management Plan shall include measures to minimize emissions from vehicles including, but not limited to, consolidating truck deliveries, prohibiting truck idling in excess of five minutes as contract conditions with carriers and by posting signs onsite, specifying truck routing to minimize congestion emissions, specifying hours of delivery to avoid peak rush-hour traffic, allowing ingress/egress only at specified entry/exit points to avoid heavily congested traffic intersections and streets, and specifying allowable locations of onsite parking.

Off-Road Mobile Sources:

A-3 Prohibit construction equipment from idling longer than five minutes at the facility under consideration as contract conditions with construction companies and by posting signs onsite.

A-4 Maintain construction equipment tuned up and with two- to four-degree retard diesel engine timing or tuned to manufacturer's recommended specifications that optimize emissions without nullifying engine warranties.

A-5 The facility operator shall survey and document the locations of construction areas and identify all construction areas that are served by electricity. This documentation shall be provided as part of the Construction Emissions Management Plan. Electric welders shall be used in all construction areas that are demonstrated to be served by electricity.

A-6 The facility operator shall survey and document the locations of construction areas and identify all construction areas that are served by electricity. This documentation shall be provided as part of the Construction Emissions Management Plan. Onsite electricity rather than temporary power generators shall be used in all construction areas that are demonstrated to be served by electricity.

A-7 If cranes are required for construction, cranes rated 200 hp or greater equipped with Tier 4 or equivalent engines shall be used. Engines equivalent to Tier 4 may consist of Tier 3 engines retrofitted with diesel particulate filters and oxidation catalysts, selective catalytic reduction, or other equivalent NOx control equipment. Retrofitting cranes rated 200 hp or greater with PM and NOx control devices must occur before the start of construction. If cranes rated 200 hp or greater equipped with Tier 4 engines are not available or cannot be retrofitted with PM and NOx control devices, the facility operator shall use cranes rated 200 hp or greater equipped with Tier 3 or equivalent engines. The facility operator shall provide documentation in the Construction Emissions Management Plan or associated subsequent status reports as information becomes available that cranes rated 200 hp or greater equipped with Tier 4 or equivalent engines are not available.

A-8 For off-road construction equipment rated 50 to 200 hp that will be operating for eight hours or more, the facility operator shall use equipment rated 50 to 200 hp equipped with Tier 4 or equivalent engines. Engines equivalent to Tier 4 may consist of Tier 3 engines retrofitted with diesel particulate filters and oxidation catalysts, selective catalytic reduction, or other equivalent NOx control equipment. Retrofitting equipment rated 50 to 200 hp with PM and NOx control devices must occur before the start of construction. If equipment rated 50 to 200 hp equipped with Tier 4 engines is not available or cannot be retrofitted with PM and NOx control devices, the facility operator shall use equipment rated 50 to 200 hp equipped with Tier 3 or equivalent engines. The facility operator shall provide documentation in the Construction Emissions Management Plan or associated subsequent status reports as information becomes available that equipment rated 50 to 200 hp equipped with Tier 4 or equivalent engines are not available.

3.2.5.1.1 Remaining Construction Impacts

In spite of implementing the construction air quality mitigation measures above such as a WGS, or installation two or more types of air pollution control equipment concurrently, it is likely that construction air quality impacts would continue to exceed any applicable construction air quality significance thresholds and, therefore, remain significant.

3.2.5.2 Operation Mitigation Measures

Based on the evaluation Rule 12-16, operational air quality impacts from the proposed project would not exceed the Air District's operations emission thresholds for NOx, ROG, PM10 or PM2.5. Therefore, no operational mitigation measures are required. ~~Because operation air quality impacts would be generated primarily by air pollution control equipment, mitigation measures are limited because the air pollution control equipment analyzed are considered BACT (defined as lowest achievable emission rate (LAER)) or BARCT (reasonably available control technology (RACT) and, as a result, other types of control equipment may not be acceptable if they are not able to comply with LAER or RACT standards. Therefore, no mitigation measures were identified to reduce operational air quality impacts to less than significant.~~

~~Further, it may not be possible to replace a thermal oxidizer with a carbon adsorption unit in all circumstances. Therefore, it is likely that operational air quality impacts would continue to exceed the applicable operational air quality significance threshold and, therefore, remain significant.~~

3.2.6 CUMULATIVE AIR QUALITY IMPACTS

Pursuant to CEQA Guidelines §15130(a), "An EIR shall discuss cumulative impacts of a project when the project's incremental effect is cumulatively considerable, as defined in section 15065 (a)(3). Where a lead agency is examining a project with an incremental effect that is not "cumulatively considerable," a lead agency need not consider that effect significant, but shall briefly describe its basis for concluding that the incremental effect is not cumulatively considerable. Further, CEQA Guidelines §15130 requires that an EIR reflect the severity of the cumulative impacts from a proposed project and their likelihood of occurrence, but the discussion need not provide as great detail as is provided for the effects attributable to the project alone. The discussion should be guided by standards of practicality and reasonableness. Cumulative impacts are defined by CEQA as "two or more individual effects which, when considered together, are considerable or which compound or increase other environmental impacts" (CEQA Guidelines, §15355). Cumulative impacts are further described as follows:

- The individual effects may be changes resulting from a single project or a number of separate projects. (State CEQA Guidelines §15355(a).
- The cumulative impacts from several projects are the changes in the environment which result from the incremental impact of the project when added to other closely related past, present, and reasonably foreseeable future projects. Cumulative impacts can result from individually minor but collectively significant projects taking place over a period of time (CEQA Guidelines, §15355(b)).
- A "cumulative impact" consists of an impact that is created as a result of the combination of the project evaluated in the EIR together with other projects causing related impacts. An EIR should not discuss impacts which do not result in part from the project evaluated in the EIR. (CEQA Guidelines, §15130(a)(1)).

With regard to related projects or projects with related environmental impacts, because the proposed project consists of promulgating ~~either Rule 11-18,~~ Rule 12-16, ~~or both,~~ related projects would consist of other past, present, and probable future BAAQMD rules and regulations, as well as implementing control measures in the 2017 Clean Air Plan control measures.

3.2.6.1 Criteria Air Pollutants

3.2.6.1.1 Construction Air Quality Impacts

In the analysis of construction air quality impacts, it was concluded that air quality impacts from construction activities would be significant from implementing the proposed project because installing one large or two or more moderately-sized pieces of air pollution control equipment would likely exceed the applicable BAAQMD significance thresholds for construction air quality impacts. Further, it was concluded that, even after implementing mitigation measures, construction air quality impacts would continue to exceed the applicable significance thresholds for construction. Thus, the air quality impacts due to construction are considered to be cumulatively considerable pursuant to CEQA Guidelines §15064 (h)(1) and therefore, generate significant adverse cumulative construction air quality impacts. It should be noted, however, that the air quality analysis is a conservative, "worst-case" analysis so the actual construction impacts are not expected to be as great as estimated here. Further, the construction activities are temporary and would be terminated once any future construction activities are completed.

3.2.6.1.2 Operational Air Quality Impacts

~~As noted above, implementing Rule 11-18 has the potential to generate significant adverse project-specific NOx impacts because NOx emissions exceed the Air District's annual NOx significance threshold. As a result, annual NOx emission impacts from Rule 11-18 are considered to be cumulatively considerable pursuant to CEQA Guidelines §15064 (h)(1) and, therefore, are concluded to be cumulatively significant.~~ Because operational emissions for Rule 12-16 do not exceed any of the applicable operational air quality significance thresholds, which also serve as the cumulative significance thresholds, they are not considered to be cumulatively considerable (CEQA Guidelines §15064 (h)(1)) and, therefore are not expected to generate significant adverse cumulative operational impacts. ~~Adopting both rules would result in significant cumulative NOx air quality impacts, primarily generated by Rule 11-18. ROG, PM10 and PM2.5 emissions would be less than the applicable significance threshold and, therefore, are concluded to be less than significant and not cumulatively considerable for both construction and operation.~~

As discussed above, in addition to the estimated emission increases associated with the operation of new air pollution control equipment under ~~either Rule 11-18 or~~ Rule 12-16, reductions in air emissions would also be expected, some of which are potentially large (e.g., WSG). However, it is not possible to estimate those emission reductions at this point until the sources that will be controlled are known, the type of air pollution control device has been identified, appropriate engineering analyses have been completed and so forth. Nonetheless the potential emission increases are expected to be either wholly or partially offset with emission decreases.

As described in the EIR for the Clean Air Plan (BAAQMD, 2017), air quality within the Bay Area has improved since 1955 when the Air District was created and is projected to continue to improve. This improvement is mainly due to lower-polluting on-road motor vehicles, more stringent regulation of industrial sources, and the implementation of emission reduction strategies by the Air District. This trend towards cleaner air has occurred in spite of continued population growth. The Air District is in attainment of the State and federal ambient air quality standards for CO, NOx, and SO_2.

However, the Bay Area is designated as a non-attainment area for the federal and state 8-hour ozone standard. The State 8-hour standard was exceeded on 12 days in 2015 in the Air District, most frequently in the Eastern District (Livermore, Patterson Pass, and San Ramon) (see Table 3.2-2). The federal 8-hour standard was exceeded on 12 days in 2015. The Air District is unclassified for the federal 24-hour PM10 standard and is non-attainment with the State 24-hour PM10 standard. Since the District is not in attainment for the federal and state ozone standard, the state 24-hour PM10 standard, and the federal 24-hour PM2.5 standard, past projects and activities have contributed to the nonattainment air quality impacts that are cumulatively significant.

The 2017 Clean Air Plan contains numerous control measures that the District intends to impose to improve overall air quality in the District. Control measures in the 2017 Clean Air Plan included Rule 12-16 as well as a number of other control measures to control emissions from refineries as well as other stationary sources. The 2017 Clean Air Plan is expected to result in overall reductions in VOC, NOx, SOx, and PM emissions, providing an air quality benefit (BAAQMD, 2017). As reported in the Final EIR for the 2017 Air Plan, large emission reductions are expected from implementation of the 2017 Plan including reductions in ROG emissions of 1,596 tons/year; NOx emissions of 2,929 tons/year, SOx emissions of 2,590 tons/year, and PM2.5 emissions of 503 tons/year (see Table 3.2-21 of the Final EIR, BAAQMD 2017). These emission reductions are expected to help the Bay Area come into compliance or attainment with the federal and state 8-hour ozone standard, the federal and state PM10 standards, the federal 24-hour PM2.5 standards, and the state 24-hour PM2.5 standard, providing both air quality and public health benefits. The proposed Rule 12-16 is not expected to result in a cumulatively considerable contribution to the existing air quality. Emission reductions from the 2017 Plan are expected to far outweigh any potential secondary emission increases associated with implementation of the control measures in the 2017 Plan (including Rule 12-16), providing a beneficial impact on air quality and public health.

3.2.6.2 Toxic Air Contaminants

It was concluded for the analysis of TAC air quality impacts, that TAC emissions from operation of SCR, Ultracat, or WGS units would be minor and less than significant. Because operational TAC emissions do not exceed the applicable cancer and non-cancer health risk significance thresholds, they are not considered to be cumulatively considerable (CEQA Guidelines §15064 (h)(1)) and, therefore are not expected to generate significant adverse cumulative cancer and non-cancer health risk impacts. ~~In addition, reductions in TAC emissions would be expected due to implementation of Rule 11-18, but those emission reductions and the related health risk benefits cannot be estimated at this time.~~

CHAPTER 2

PROJECT DESCRIPTION

2.0 PROJECT DESCRIPTION

2.1 INTRODUCTION

Petroleum refineries are significant sources of harmful pollutants on both the global (climate pollutants i.e., greenhouse gases), regional (criteria pollutants), and local scale (toxic air contaminants and particulate matter). Many Bay Area residents have expressed concern about the impact of this pollution on the environment and public health, particularly those that may disproportionately impact communities near refineries. Though refinery emissions have declined over time, it is possible that as refinery operations change in the future, emissions of these pollutants could increase. ~~In response to these concerns, the Board of Directors of the Bay Area Air Quality Management District (Air District) has directed staff to bring forward two rules for their consideration: one that reflects policy recommended by some environmental advocacy organizations; and an approach recommended by Air District staff.~~

Communities for a Better Environment (CBE) and several associated organizations have recommended that the Air District adopt new Regulation 12, Rule 16: Petroleum Refining Facility-Wide Emissions Limits (Rule 12-16 or "Refining Caps Rule"). This rule would set numeric limits on specific refinery emissions. Rule 12-16 would apply only to the Bay Area's five petroleum refineries and three facilities associated with the refineries. This EIR addresses the potential environmental impacts of implementing Rule 12-16.

~~The staff of the Air District has developed a different approach that directly addresses concerns about health risks to communities exposed to air pollution. The staff recommendation is that the Air District adopt a new Regulation 11, Rule 18: Reduction of Risk from Air Toxic Emissions at Existing Facilities (Rule 11-18 or "Toxic Risk Reduction Rule"). Rule 11-18 would apply to all facilities in the Bay Area whose emissions of toxic air contaminants may result in a significant risk to nearby residents and workers, including petroleum refineries. The purpose of Rule 11-18 is to reduce the public's exposure to health risks associated with the emissions of toxic air contaminants (TACs) from stationary sources by reducing those risks to the lowest feasible levels.~~

~~Because the Board of Directors of the Air District intends to consider these rules within the same timeframe, staff is preparing one Environmental Impact Report (EIR) to cover both rules. The intent of the single EIR is to ensure that all of the potential environmental impacts for both rules are considered and comprehensively addressed. Although they are being considered at the same time, and both would affect refineries, the two rules are functionally independent. Adoption of one does not depend on adoption of the other. The Board of Directors could adopt either rule, both rules, or neither rule.~~

2.1.1 Rule 12-16 – Refinery Emissions Caps Rule

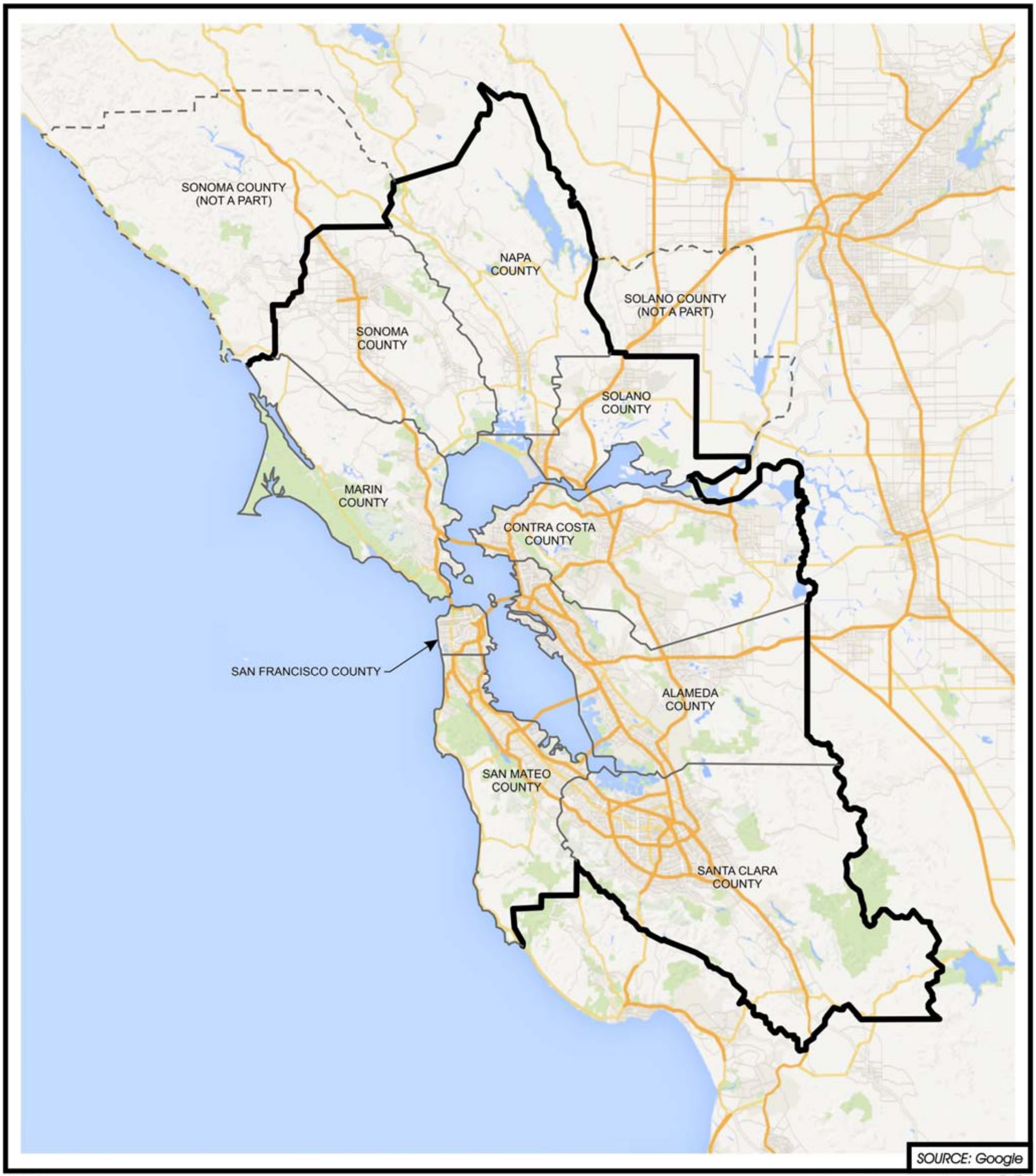
Rule 12-16 reflects a policy recommendation from CBE and their associated organizations (henceforth called "CBE"). The rule, as proposed by CBE, would limit the emissions of climate pollutants and three criteria pollutants: greenhouse gases (GHGs), particulate matter (PM), oxides of nitrogen (NOx), and sulfur dioxide (SO_2) from petroleum refineries and three associated facilities. The rule would establish facility-wide emissions limits for the covered pollutants at each of the affected facilities to ensure that each facility does not increase emissions due to changes in operation, crude or product slates; or increases in production. Each facility's emissions limits would be set at the maximum-annual emissions reported for that facility in the period from 2011 through 2015 with an additional allowance or "threshold factor" of seven percent over the maximum annual emission rate for each pollutant.

~~2.1.2 Rule 11-18 Toxic Risk Reduction Rule~~

~~Rule 11-18, as drafted by Air District staff, would ensure that emissions of TACs from existing facilities do not pose an unacceptable health risk to people living and working nearby. The rule would use the most up-to-date assumptions about the risk of compounds and would require the facility to take action to reduce risk below a specified risk threshold if the facility exceeds the risk thresholds. If the facility could not devise a means to reduce the risk below the specified risk level, the facility would be required to install best available retrofit control technology for toxic pollutants (TBARCT) on every significant source of TAC emissions at the facility.~~

2.2 PROJECT LOCATION

The BAAQMD has jurisdiction of an area encompassing 5,600 square miles. The Air District includes all of Alameda, Contra Costa, Marin, San Francisco, San Mateo, Santa Clara, and Napa Counties, and portions of southwestern Solano and southern Sonoma counties. The San Francisco Bay Area is characterized by a large, shallow basin surrounded by coastal mountain ranges tapering into sheltered inland valleys. The combined climatic and topographic factors result in increased potential for the accumulation of air pollutants in the inland valleys and reduced potential for buildup of air pollutants along the coast. The Basin is bounded by the Pacific Ocean to the west and includes complex terrain consisting of coastal mountain ranges, inland valleys and bays (see Figure 2.2-1). ~~Proposed Regulations 11-18 would affect stationary sources of TAC emissions, including five petroleum refineries, within the Bay Area.~~ Proposed Rule 12-16 would affect the five Bay Area petroleum refineries and three associated facilities.



SOURCE: Google

Environmental Audit, Inc.

BAY AREA AIR QUALITY MANAGEMENT DISTRICT

Project No. 3013

Figure 2.2-1

N:\3013\BAAQMD Map.cdr

2.3 PROJECT OBJECTIVES

~~The objectives of Toxic Risk Reduction Rule (Reg. 11-18) are to:~~

- ~~Reduce the public's exposure to health risks associated with the emissions of TACs from stationary sources;~~
- ~~Incorporate the most up-to-date health risk methodologies and health values into the Air District's risk evaluation process for existing stationary sources of TACs;~~
- ~~Ensure the facilities that impact the most sensitive and overburdened communities reduce their associated health risk in an efficient and expeditious manner;~~
- ~~Provide the public opportunity to comment on the draft HRAs to provide transparency and clarity to the process; and~~
- ~~Provide the public opportunity to comment on risk reduction plans as they are drafted by the affected facilities.~~

The objectives of the Refining Emission Caps Rule (Reg. 12-16) are to:

- Protect air quality, public health, and the climate from increases in annual facility-wide mass emissions of GHGs, PM, NOx, and sulfur oxides (SOx) caused by changes in refinery oil feed quality or quantity, refinery or support equipment or operation, or combinations of these causes, by preventing any significant increase in these emissions;
- Protect the climate and public health by preventing any significant increase in these emissions at refineries and associated facilities from increasing the emission intensity of the production of transportation fuels;
- Protect community and public health by preventing any significant increase in these emissions from worsening hazards for which HRA methods may not account, including but not limited to acute and chronic ambient PM, NOx, SOx, and PM exposure hazards;
- Complement other air quality, public health, and climate measures by discouraging investment in new refinery equipment that would lead to increased emissions of GHG, PM, NOx, or SOx from Bay Area refineries.

2.4 BACKGROUND AND PROJECT DESCRIPTION

2.4.1 BACKGROUND

Rule 12-16 would affect the five petroleum refineries currently located in the Bay Area within the jurisdiction of the Air District:

- Chevron Products Company (Richmond),
- Phillips 66 Company – San Francisco Refinery (Rodeo),
- Shell Martinez Refinery (Martinez),
- Tesoro Refining and Marketing Company (Martinez), and
- Valero Refining Company – California (Benicia).

The rule would also affect three refinery-related facilities:

- Air Liquide (Richmond),
- Air Products (Martinez), and
- Martinez Cogen LP (Martinez).

~~Rule 11-18 would affect hundreds of facilities that emit TACs. The Air District has determined that these toxic emissions need to be reduced in order to be more protective of public health. These facilities include data centers, petroleum refineries, a cement kiln, gasoline dispensing facilities, etc., and emit a variety of TACs that can adversely impact public health. TACs include compounds such as diesel particulate matter (DPM), benzene, polycyclic aromatic hydrocarbons (PAHs), and 1,3-butadiene.~~

The primary focus of CBE's concern has been petroleum refineries. Petroleum refineries convert crude oil into a wide variety of refined products, including gasoline, aviation fuel, diesel and other fuel oils, lubricating oils, and feed stocks for the petrochemical industry. Crude oil consists of a complex mixture of hydrocarbon compounds with smaller amounts of impurities including sulfur, nitrogen, oxygen and metals (e.g., iron, copper, nickel, and vanadium).

Air pollutants are categorized based on their properties, and the programs under which they are regulated. Air pollutants include: (1) criteria pollutants, (2) toxic pollutants, and (3) climate pollutants (or GHGs). Additional categories of air contaminants include odorous compounds and visible emissions.

Criteria pollutants are emissions for which Ambient Air Quality Standards (AAQS) have been set and include: (1) carbon monoxide (CO), (2) nitrogen dioxide (NO_2) and NO_X, (3) PM in two size ranges – aerodynamic diameter of 10 micrometers or less (PM_{10}), and aerodynamic diameter of 2.5 micrometers or less ($PM_{2.5}$), (4) volatile organic compounds (VOC), and (5) sulfur dioxide (SO_2). Other compounds, specifically volatile organic compounds (VOC), can react in the atmosphere to form ozone and are often regulated along with criteria pollutants. These compounds can have both localized and regional impacts. All of these criteria pollutants are emitted by petroleum refineries, as well as numerous other stationary sources and mobile sources (automobiles, trucks, locomotive engines, marine vessels, construction equipment, etc.).

TACs are emissions for which AAQS have generally not been established, but may result in human health risks. The State list of TACs currently includes approximately 190 separate chemical compounds and groups of compounds. These compounds tend to have more localized impacts. There are many TACs potentially emitted from industrial sources, including refineries.

GHGs are emissions that include carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), and three groups of fluorinated compounds (i.e., hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6)), and are the major anthropogenic GHGs. The impact of these compounds is global in nature and require a global reduction to result in a beneficial impact on the global climate. GHGs emitted from petroleum refineries include CO_2, CH_4 and N_2O.

The regulatory approach~~es~~ for Rule~~s 11-18 and~~ 12-16 ~~are~~ is summarized below and include the following basic elements.

~~2.4.1.1 Regulation 11, Rule 18~~

- ~~The Air District would screen all facilities that report toxic emissions. From this screening, the Air District would determine each facility's prioritization score. The Air District would conduct health risk assessments (HRA) for facilities with a cancer risk prioritization score of 10 or greater or a non-cancer prioritization score of 1.0 or greater. The HRAs would incorporate the new Office of Environmental Health Hazard Assessment (OEHHA) protocols and health risk values adopted in March 2015, the Risk Management Guidelines adopted in July 2015 by the California Air Resources Board (CARB) and the California Air Pollution Control Officers Association (CAPCOA), as well as revised Air District HRA guidelines. The Air District would schedule the development of the HRAs according to prioritization score and then according to type of facility.~~

- ~~Facilities that pose a cancer risk in excess of 10 per million or a chronic or acute hazard index in excess of 1.0 must either:~~
  - ~~Reduce the facility cancer risk below 10 per million and reduce the chronic and acute hazard indices below 1.0; or~~
  - ~~Install TBARCT on all significant sources of toxic emissions.~~

2.4.1.1 Regulation 12, Rule 16

- Rule 12-16 would apply to each of the Bay Area petroleum refineries and three support facilities;

- Rule 12-16 would establish facility-wide emissions limits for GHGs, $PM_{2.5}$ and PM_{10}, NOx, and SO_2 at each of the affected facilities based on the following method:
    - Each facility emissions limit would be set at the maximum-annual emissions reported for that facility in the period from 2011 through 2015, and
    - Include an additional allowance or "threshold factor" that would equal seven percent over the maximum for GHGs, $PM_{2.5}$ and PM_{10}, NOx, and SO_2.

- Emissions from start-ups, shut-downs, maintenance and malfunctions would be subject to the cap; and,

- Compliance with the emissions limits would be based on comparing the annual emissions inventory with the facility-wide emissions limit for each covered pollutant. Any annual emissions inventory that exceeds the established pollutant emissions limit for the affected facility would be a violation of the rule.

2.4.2 PROJECT DESCRIPTION

The description of ~~Regulation 11, Rule 18 and~~ Regulation 12, Rule 16 ~~are~~ is provided below.

~~2.4.2.1 Regulation 11, Rule 18~~

~~The rule would require facilities that pose a site-wide health risk in excess of the risk action level threshold of ten per million cancer risk or 1.0 hazard index for both chronic and acute risk to reduce that risk below the threshold through the implementation of a risk reduction plan approved by the Air District or demonstrate that all significant sources of toxic emissions are controlled TBARCT; a significant source of toxic emission is one that poses a health risk of 1.0/M cancer or 0.2 hazard index. The rule would be implemented in four phases based on either a facility's prioritization score or the toxic emissions source.~~

~~2.4.2.1.1 Administrative Procedures~~

~~The Toxic Risk Reduction Rule would utilize the annual toxic emissions inventories reported to the Air District by sources that emit toxic compounds. From the toxic emissions inventory data, Air District would conduct a site-specific Health Risk Screening Analysis (HRSA). The HRSA would assess the potential for adverse health effects from public exposure to routine and predictable emissions of TACs. Procedures used for completing HRSAs are based on guidelines adopted by CARB/CAPCOA. From these HRSAs, the Air District would determine each facility's prioritization score. The facility prioritization score or the toxic emissions source type would be used to determine which phase a facility would be placed. In establishing the prioritization level for a facility, the Air District would consider:~~

- ~~The amount of toxic pollutants emitted from the facility;~~
- ~~The toxicity of these materials;~~
- ~~The proximity of the facility to potential receptors; and~~
- ~~Any other factors that the Air District deems to be important.~~

~~The rule would be implemented in four phases based on either a facility's prioritization score or the toxic emissions source type as illustrated in Table 2.4-1. (Prioritization scores for all potentially affected facilities are expected to be completed by the end of 2017).~~

~~TABLE 2.4-1~~

~~Implementation Phases~~

~~Phase~~	~~Criterion~~	~~HRAs~~	~~Risk Reduction Plans~~	~~Plan Implementation~~
~~1~~	~~Cancer PS(1) > 250 or Non-cancer PS > 2.5~~	~~2017 – 2018~~	~~2018 – 2019~~	~~2019 – 2022~~
~~2~~	~~Cancer PS > 10 or Non-cancer PS > 1.0~~	~~2019 – 2021~~	~~2021 – 2022~~	~~2022 – 2025~~
~~3~~	~~Diesel IC Engines~~	~~2021 – 2013~~	~~2023 – 2024~~	~~2024 – 2027~~
~~4~~	~~Retail Gas Stations~~	~~2023 - 2024~~	~~2024-2025~~	~~2025 - 2028~~

~~(1) PS = prioritization score~~

~~The Air District would conduct HRAs for facilities in accordance with the OEHHA HRA Guidelines and the CARB/CAPCOA Risk Management Guidelines that were updated in 2015. These Guidelines were updated pursuant to the Children's Environmental Health Protection Act (Senate Bill 25), which required that OEHHA develop health risk assessment procedures that ensure infants and children are protected from the harmful effects of air pollution. Using the results of the HRAs, the Air District would determine whether a facility would be affected by Rule 11-18. The rule would affect facilities with health risk impacts that exceeded any of the risk action level thresholds of ten per million cancer risk or 1.0 hazard index for both chronic and acute risk. The Air District would notify facilities of their health risk score. A facility with a risk action level exceeding the threshold(s) would be required to reduce the risk below the threshold(s) by implementing a risk reduction plan within five years of plan approval, or demonstrate that all significant sources of toxic emissions are controlled by TBARCT within the same three-year period; a significant source of toxic emission is one that poses a health risk of 1.0 per million cancer or 0.2 hazard index.~~

~~2.4.2.1.2 Health Risk Assessments~~

~~The Air District uses a variety of tools to determine where air quality health impacts may be occurring in the Bay Area, to assess the relative magnitude of these health impacts~~

~~compared to other locations, and to determine how to best focus Air District resources in order to reduce these health impacts. HRAs are one of the tools that can be used to assess the relative magnitude of health hazards. HRAs are designed to quantify the potential health impacts that people and communities may be experiencing due to specific sources or facilities or that may occur in the future due to proposed projects or proposed changes at a facility. An HRA consists of four basic steps: 1) hazard identification; 2) exposure assessment; 3) dose response assessment; and 4) risk characterization. The Air District conducts HRAs using standardized methodologies for each of these steps. The Air District HRAs would be prepared in accordance with the most recent guidelines adopted by OEHHA in March 2015.~~

~~Air District staff believes that new facility-wide HRAs should be performed including improved emission inventories, updated health effects values, and the most recent HRA methodologies. Rule 11-18 would require that the Air District conduct HRAs utilizing the most recent OEHHA HRA Guidelines along with more refined emissions inventories.~~

~~2.4.2.1.3 Pollutant Coverage~~

~~The Toxic Risk Reduction Rule would address TAC emissions from existing stationary sources. TAC emissions from new and modified sources are addressed under Air District Regulation 2, Rule 5. The California Health and Safety Codes §39655 defines a TAC as "an air pollutant which may cause or contribute to an increase in mortality or in serious illness, or which may pose a present or potential hazard to human health. A substance that is listed as a hazardous air pollutant pursuant to subsection (b) of §112 of the federal act (42 U.S.C. §7412(b)) is a toxic air contaminant." For the purposes of this rule, TACs consists of the substances listed in Air District Regulation 2, Rule 5: New Source Review of Toxic Air Contaminants (Table 2-5-1.)~~

~~Some of the key pollutants to be addressed under the Toxic Risk Reduction Rule include the following:~~

~~Benzene:~~

~~Benzene is carcinogenic and occurs throughout the Bay Area. Most of the benzene emitted in the Bay Area comes from motor vehicles, including evaporative leakage and unburned fuel exhaust. Stationary sources contribute 13 percent of the benzene statewide. The primary stationary sources of benzene emissions include gasoline stations, petroleum refining, electricity generation, and cement production.~~

~~1,3 Butadiene:~~

~~1,3-butadiene is another carcinogen that is generated by gasoline and biomass combustion. Motor vehicle exhaust and fires are the most common sources. It is also produced during petroleum refining, and it is used in rubber and plastics manufacturing.~~

~~Polycyclic aromatic hydrocarbons (PAHs):~~

~~PAHs are a set of hydrocarbons formed of multiple benzene rings. Several PAHs have been shown to be carcinogenic, the best-studied of which is benzo(a)pyrene. Although PAHs are emitted during petroleum refining, in the Bay Area the vast majority derive from fossil fuel and wood combustion.~~

~~Diesel Particulate Matter (DPM):~~

~~DPM is the primary source of ambient risk based on risk analysis, followed by benzene and 1,3-butadiene. DPM emissions sources mainly include mobile sources, such as heavy-duty trucks, buses, construction equipment, locomotives, and ships, but also stationary sources such as stationary diesel engines and backup generators.~~

~~2.4.2.1.4 Source Coverage~~

~~The Toxic Risk Reduction Rule would apply to all sources of TAC emissions from "stationary sources" in the Bay Area. Stationary sources, as opposed to mobile sources such as trucks and other vehicles, are the sources over which the Air District has regulatory jurisdiction.~~

~~The Toxic Risk Reduction Rule would apply to a wide variety of sources and facilities located throughout the Bay Area, including data centers, petroleum refineries, chemical plants, wastewater treatment facilities, foundries, forges, landfill operations, hospitals, crematoria, gasoline dispensing facilities (i.e., gasoline stations), colleges and universities, military facilities and installations and airline operations. The Air District estimates that hundreds of facilities could be impacted by this rule.~~

2.4.2.1 Regulation 12, Rule 16

2.4.2.1.1 Pollutant Coverage

The Refining Cap Rule would limit the emissions of climate pollutants (GHGs) and three criteria pollutants (PM – both PM_{10} and $PM_{2.5}$, NOx, and SO_2) from refineries and other refining related facilities to a specific baseline plus an allowance; thereby establishing a "cap" for each of these emissions that the facility could not exceed.

Greenhouse Gases:

GHGs refer to gases that contribute to anthropogenic climate change (i.e., global warming). In addition to negative impacts on air quality as higher temperatures contribute to increased levels of ozone and PM, climate change may cause a wide range of ecological, social, economic, and demographic impacts. GHGs include carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), and three groups of fluorinated compounds (i.e., hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6)). CO_2 is released to the atmosphere when fossil fuels (oil, gasoline, diesel, natural gas, and coal), solid waste, and wood or wood products are burned. CH_4 is emitted during the production and transport of coal, natural gas, and oil. CH_4 emissions also result from the decomposition of organic waste in municipal solid waste landfills and the raising of livestock. N_2O is emitted during agricultural and industrial activities, as well as during combustion of solid waste and fossil fuels. Fluorinated hydrocarbons: HFCs, PFCs, and SF_6, are generated in a variety of industrial processes. Although these gases are small in terms of their absolute mass, they are potent agents of climate change as expressed by their global warming potential.

Particulate Matter:

PM is a complex pollutant composed of an assortment of tiny airborne particles that vary in size and mass (ultrafine, fine, and coarse), physical state (solid or liquid), chemical composition, toxicity, and how they behave in the atmosphere. These particles originate from a variety of man-made and natural sources, including fossil fuel combustion, residential wood burning and cooking, wildfires, volcanoes, sea salt, and dust. Fine and ultrafine particles are so small, they can bypass the body's natural defenses and penetrate deep into the lungs, bloodstream, brain and other vital organs, and individual cells. Health studies have shown that exposure to PM can have a wide range of negative health effects, including triggering asthma attacks, chronic bronchitis, impaired lung development in children, heart attack, stroke, and premature death. Residential wood burning is the largest source of PM in the Bay Area during winter days. On an annual basis, mobile sources such as cars, trucks, ships and trains are the largest source of PM in the Bay Area.

Nitrogen Oxides:

Nitrogen oxides are a group of gases that form when nitrogen reacts with oxygen during combustion, especially at high temperatures. These compounds (including nitric oxide and nitrogen dioxide), can contribute significantly to air pollution, especially in cities and areas with high motor vehicle traffic. In the Bay Area, nitrogen dioxide appears as a brown haze. At higher concentrations, nitrogen dioxide can damage sensitive crops, such as beans and tomatoes, and aggravate respiratory problems.

Sulfur Oxides:

Heating and burning fossil fuels (such as coal and oil) release the sulfur present in these materials. In areas where large quantities of fossil fuels are used, sulfur oxides can be a major air pollution problem. The most common kind of sulfur oxide is SO_2. This substance can react with oxygen to form sulfur trioxide, which can form sulfuric acid mist in the presence of moisture. These contaminants can damage vegetation and negatively impact the health of both humans and animals.

2.4.2.1.2 Affected Facilities

The Refining Caps Rule would apply to each of the Bay Area's five petroleum refineries and to three additional support facilities. The five refineries are Chevron Refinery in Richmond, Shell Refinery in Martinez, Phillips 66 Refinery in Rodeo, Tesoro Refinery in Martinez, and Valero Refinery in Benicia. The three affected support facilities are Air Liquide in Richmond, Air Products in Martinez, and Martinez Cogen LP in Martinez.

2.4.2.1.3 Emissions Limits

The draft emissions limit for each covered pollutant and each affected facility are shown in Table 2.4-1. A numeric limit on the annual mass emission rate of each air pollutant specified would be applied to each facility specified in the table. The limit is equal to the maximum-year actual emissions reported in 2011–2015 plus the additional allowance, or threshold factor, of seven percent that is intended to account for normal year-to-year variations in emissions.

2.4.2.1.4 Changes in Monitoring Methods

CBE intends that these limits would change if the quantity of reported emissions changed solely due to a change in the method of monitoring or estimating emissions. Air District staff will work with CBE to capture this intent either in the rule language or in the plan for implementing the rule.

TABLE 2.4-1

Enforceable Emissions Limits on Refinery-Wide Emissions[(a)]

Facility		Pollutants				
Name	**Facility ID Number**	**GHG**[(b)] (thousands of metric tons)	**$PM_{2.5}$**[(c)] (tons)	**PM_{10}**[(c)] (tons)	**NOx**[(c)] (tons)	**SO_2**[(c)] (tons)
Chevron	A-0010	4,774	502	526	971	394
Shell	A-0011	4,560	495	589	1,068	1,455
Phillips 66	A-0016	1,608	75	83	334	443
Tesoro	B-2758/B-2759	2,615	77.7	97	1,015	644
Valero	B-2626/B-3193	3,145	133	133	1,300	69.6
Martinez Cogen LP	A-1820	451	18.8	18.8	119	2.3
Air Liquide	B-7419	947	16.1	17.3	13.8	2.5
Air Products	B-0295	290	9.7	10.4	3.4	2.3

(a) Annual facility-wide emission limits.

(b) GHG: greenhouse gas emissions (CO_2e) as reported under CARB's Mandatory Reporting requirements.

(c) $PM_{2.5}$ = "fine" particulate matter, PM_{10} = "respirable" particulate matter, NOx = oxides of nitrogen, SO_2 = sulfur dioxide as reported in the facility's annual emission inventory.

2.5 SOURCES AFFECTED BY REGULATIONS~~ 11-18 AND~~ 12-16 AND APPLICABLE CONTROL TECHNOLOGIES

~~Rule 11-18: As indicated in the project description above, to comply with Rule 11-18 existing affected facilities that pose a health risk in excess of the risk action level threshold of ten per million cancer risk or 1.0 hazard index for both chronic and acute non-cancer risk must reduce that risk below the threshold through the implementation of a risk reduction plan approved by the Air District. To comply with the risk reduction plan requirements, facility operators could reduce operations or, to maintain existing operations, change the nature of the toxic emissions either through modification of stack emission parameters or through toxic emission reductions, or install air pollution control equipment that meets TBARCT requirements.~~

~~Rule 12-16:~~ Rule 12-16 would establish facility-wide annual emissions limits for GHGs, $PM_{2.5}$ and PM_{10}, NOx, and SO_2 at each of the five Bay Area refineries and three refinery-related facilities (see Table 2.4-1). Any affected facility that exceeds any applicable annual emissions limits would be in violation of the draft rule. To comply with the annual facility-wide emission limits, operators of affected facilities could also reduce operations or install air pollution control technologies consistent with BARCT.

~~Discussion: Under both rules' adoption scenarios, t~~The NOP/IS for the proposed project identified potentially significant adverse secondary environmental impacts resulting primarily from installing air pollution control technologies. Therefore, the analysis of potentially significant environmental impacts in Chapter 3 is based on secondary impacts from installing air pollution control equipment. To analyze environmental impacts, ~~from either or both draft rules,~~ it is necessary to identify the emission sources that would be subject to the ~~each~~ rule's requirements and the most likely types of control technologies anticipated to be used to ensure compliance with each rule.

It is not specifically known what types of equipment would be affected by ~~either~~ Rule 12-16. However, based on the Air District's emissions inventory database, ~~TAC and criteria pollutant emissions from~~ sources likely to be affected by ~~either~~ Rule 12-16 can be identified. The emission sources most likely to be affected by draft Rule~~s 11-18 and~~ 12-16 are identified and briefly described in the following sections.

~~2.5.1 Sources that May Be Subject to Regulation 11, Rule 18~~

~~Draft Rule 11-18 would apply to a wide range of commercial, industrial, and municipal facilities including data centers, petroleum refineries, chemical plants, wastewater treatment facilities, foundries, forges, landfill operations, hospitals, crematoria, gasoline dispensing facilities (i.e., gasoline stations), power plants, colleges and universities, military facilities and installations, and airline operations. Table 2.5-1 shows the most likely types of facilities anticipated to be affected by draft Rule 11-18, TAC emission sources at affected facilities most likely to be affected by the draft rule and the primary TAC emissions that would be controlled.~~

~~Table 2.5-1~~
~~Summary of Toxic Air Contaminant Emitting Facilities and Sources~~

~~Facility~~	~~Sources~~	~~Primary Risk Driver(s)~~
~~Refineries~~	~~Fugitive Emissions~~ ~~Stack Emissions~~ ~~Diesel Engines~~ ~~Cooling Towers~~ ~~Wastewater Treatment Operations~~	~~Benzene~~ ~~Diesel PM~~ ~~Formaldehyde~~ ~~1,3-Butadiene~~ ~~Chromium VI~~ ~~Nickel~~
~~Data Centers~~	~~Stationary Diesel Engines~~	~~Diesel PM~~
~~Cement Manufacturing~~	~~Stack Emissions~~ ~~Fugitive Emissions~~	~~Chromium VI~~
~~Chemical Plants~~	~~Stack Emissions~~ ~~Fugitive Emissions~~	~~Formaldehyde~~ ~~Carbon Tetrachloride~~ ~~Sulfuric Acid Mist~~ ~~Diesel PM~~
~~Crematoria~~	~~Stack Emissions~~	~~Chromium VI~~ ~~Mercury~~
~~Landfills~~	~~Fugitive Emissions~~	~~Vinyl Chloride~~ ~~Hydrogen Sulfide~~ ~~Benzene~~ ~~Acrylonitrile~~
	~~Diesel Engines~~ ~~Energy Plants~~	~~Diesel PM~~ ~~Formaldehyde~~
~~Foundries~~	~~Fugitive Emissions~~	~~Dioxin~~ ~~Manganese~~ ~~Lead~~ ~~Chromium VI~~ ~~Mercury~~ ~~Cadmium~~ ~~Nickel~~ ~~Arsenic~~ ~~PAHs~~ ~~Copper~~
~~Sewage Treatment Facilities~~	~~Fugitive Emission~~ ~~Stack Emissions~~	~~Diesel PM~~ ~~Hydrogen Sulfide~~ ~~Cadmium~~ ~~Mercury~~
~~Power Plants~~	~~Stack Emissions~~	~~Formaldehyde~~ ~~Ammonia~~ ~~Benzene~~ ~~Diesel PM~~
~~Gasoline Stations~~	~~Fugitive Emissions~~	~~Benzene~~ ~~Ethyl Benzene~~
~~Military Facilities~~	~~Diesel Engines~~	~~Diesel PM~~
~~Manufacturing~~	~~Diesel Engines~~	~~Diesel PM~~

~~Facilities affected by draft Rule 11-18 operate a wide variety of sources of toxic emissions, including diesel-fueled internal combustion engines, wastewater treatment, combustion~~

~~sources, evaporative and fugitive emissions, etc. The Air District estimates that hundreds of facilities could potentially be affected by this draft rule. The following subsections briefly describe the most likely facilities and emissions sources affected by Draft Rule 11-18.~~

~~2.5.1.1 Refineries~~

~~Petroleum refineries convert crude oil into a wide variety of refined products, including gasoline, aviation fuel, diesel and other fuel oils, lubricating oils, and feed stocks for the petrochemical industry. Crude oil consists of a complex mixture of hydrocarbon compounds with smaller amounts of impurities including sulfur, nitrogen, oxygen and metals (e.g., iron, copper, nickel, and vanadium). Crude oil that originates from different geographical locations may vary with respect to its composition, thus, potentially generating different types and amounts of TAC emissions.~~

~~Fugitive Emissions Sources: Petroleum refineries include a large number and wide variety of fugitive emissions sources. Fugitive emissions are emissions of gases or vapors from pressurized equipment due to leaks and other unintended or irregular releases of gases during the crude refining process and do not include pollutants vented to an exhaust stack before release to the atmosphere. Generally, any processes or transfer areas where leaks can occur are sources of fugitive emissions. Fugitive emissions sources include, but are not limited to the following: valves, connectors (i.e., flanged, screwed, welded or other joined fittings), pumps, compressors, pressure relief devices, and diaphragms in VOC service. Similarly, tanks storing crude oil or petroleum products also produce fugitive emissions. The primary TAC associated with fugitive emissions sources is benzene.~~

~~Stack Emissions: There are two primary sources of TAC emissions from exhaust stacks at petroleum refineries, delayed coking units (DCUs) and petroleum coke calciners (PCCs). These equipment and processes are briefly described in the following paragraphs.~~

~~*Delayed Coking:* Delayed coking is a petroleum refinery process that converts mostly heavy residual oils, also known as residuum or "resid" for short, from vacuum distillation towers into gasoline, light gas oil and heavy gas oil. Petroleum coke is a by-product of the coking process. The resid is fed into a fractionation tower and the bottom fraction (e.g., the heavy components of the resid), is passed through a heater as it makes its way to a coke drum under steam injection. The purpose of the steam injection is to delay coking or the solidification of the hot material until it reaches the drum, hence the name "delayed coker." When heated to high temperatures, the heavy hydrocarbon chains break into smaller, lighter molecules that rise to the top of the coke drum as vapors that are routed back to the fractionation tower for more separation into gas, gasoline, and other higher value liquid products. Even after heating, the heavier components remain in the coke drum. Within approximately 30 minutes to one hour, the material left behind in the drum turns into, petroleum coke, a coal-like substance. At the end of the coking process, the drum is then vented to the atmosphere until the internal pressure of the drum equals ambient pressure. TAC emissions from the DCU primarily include heavy metals.~~

~~At the federal level, in 2008, the USEPA promulgated a regulation in Chapter 40, Part 60, Subpart Ja of the Code of Federal Regulations (40 CFR 60 Subpart Ja) - Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction or Modification Commenced after May 14, 2007, specifically applicable to DCU operations that establishes a vent limit of five pounds per square inch, gauge (psig) for coke drums at new or modified DCUs. By depressurizing the coke drum beyond the federal requirement, to two psig for example, for both new and existing DCUs~~ ~~$PM_{2.5}$~~~~, and sulfur as~~ ~~H_2S~~ ~~emission reductions can be achieved with the co-benefit of additional VOC and GHG (methane) emission reductions.~~

~~*Petroleum Coke Calciner:*~~ ~~Petroleum coke is processed in a delayed coker unit (described above) to generate a carbonaceous solid referred to as “green coke,” a commodity. To improve the quality of the product, if the green coke has a low metals content, it will be sent to a calciner to make calcined petroleum coke. Calcined petroleum coke can be used to make anodes for the aluminum, steel, and titanium smelting industry. If the green coke has a high metals content, it is used as a fuel grade coke by the fuel, cement, steel, calciner and specialty chemicals industries.~~

~~The process of making calcined petroleum coke begins when the green coke feed from the delayed coker unit is screened and transported to the calciner unit where it is stored in a covered coke storage barn. The screened and dried green coke is introduced into the top end of a rotary kiln and is tumbled by rotation under high temperatures that range between 2,000 and 2,500 degrees Fahrenheit (°F). The rotary kiln relies on gravity to move coke through the kiln countercurrent to a hot stream of combustion air produced by the combustion of natural gas or fuel oil. As the green coke flows to the bottom of the kiln, it rests in the kiln for approximately one additional hour to eliminate any remaining moisture, impurities, and hydrocarbons. Once discharged from the kiln, the calcined coke is dropped into a cooling chamber, where it is quenched with water, treated with de-dusting agents to minimize dust, and carried by conveyors to storage tanks. TAC emissions generated when the green coke is processed under high heat conditions in the rotary kiln are primarily heavy metals.~~

~~Stationary Diesel Internal Combustion Engines (ICEs):~~ ~~Stationary diesel ICEs are often used to provide electricity in areas of a refinery that may not have access to electricity power lines from the local electric utility or other onsite sources of electricity, used as a backup source of electricity in the event of a power outage, or as a means of pumping liquids between different refinery equipment. Four-stroke cycle ICEs are more commonly used than two-stroke ICEs. Stationary diesel ICEs operate by drawing air into a cylinder and then injecting fuel after the air has been compressed. Stationary diesel ICEs rely on high temperature alone for ignition. Stationary diesel ICEs are often referred to as compression ignition engines because the high temperature is the result of compressing air above the piston as it travels upward. The power output of a diesel ICE is controlled by varying the amount of fuel injected into the air, thereby, varying the fuel-air ratio. The~~

~~main advantage of using a diesel engine is its high thermal efficiency~~[1]~~, which can exceed 50 percent. However, diesel ICE exhaust tends to be high in NOx and particulate emissions, both visible (smoke) and invisible. Diesel particulates were also classified as a TAC by CARB in in 1998.~~

~~Cooling Towers: A cooling tower is a heat rejection device, which extracts waste heat from various processes to the atmosphere though the cooling of a water stream to a lower temperature. Cooling towers are open water recirculating devices that use fans or natural draft to draw or force air through the device to cool water by evaporation and direct contact. The type of heat rejection in a cooling tower is termed "evaporative" in that it allows a small portion of the water being cooled to evaporate into a moving air stream to provide significant cooling to the rest of that water stream. The heat from the water stream transferred to the air stream raises the air's temperature and its relative humidity to 100 percent and this air is discharged to the atmosphere. TAC emissions from cooling towers can include fugitive VOCs leaked into the cooling water, which may include benzene and 1,3-butadiene and other toxic VOCs.~~

~~Wastewater Treatment Operations: Wastewater treatment operations provide a means of treating water that has come into contact with petroleum hydrocarbons. The first stage of a typical wastewater treatment process is the American Institute of Petroleum (API) separator, which physically separates the free oil and solids from the water. Gravity allows any oil in the water to rise to the surface of the separator and any solid particles to sink to the bottom. A continually moving scraper system pushes oil to one end and the solids to the other. Both are removed and the recovered oil is sent back to the Refinery for reprocessing. Small suspended oil particles are then typically removed in the Dissolved Air Flotation unit. Wastewater is sent to the activated sludge units, where naturally-occurring microorganisms feed on the dissolved organics in the wastewater, and convert them to water,~~ ~~CO_2~~ ~~and nitrogen gas, which can be safely released into the atmosphere. Finally, wastewater enters the clarifying tanks, where the microorganisms settle to the bottom while the treated wastewater flows away. The primary TAC emission from wastewater treatment systems is benzene.~~

~~2.5.1.2 Data Centers~~

~~A data center is a facility used to house computer systems and associated components, such as telecommunications and data storage systems. It generally includes redundant or backup power supplies, redundant data communications connections, environmental controls (e.g., air conditioning, fire suppression) and various security devices.~~

~~Stationary Diesel ICEs: Because a power outage can badly damage computer telecommunications and storage systems, backup power supplies are essential. Backup~~

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[1] Thermal efficiency is defined as the amount of work produced by the engine divided by the amount of chemical energy in the fuel that can be released through combustion. This chemical energy is often referred to as net heating value or heat of combustion of the fuel.

~~power supplies may include backup stationary diesel ICEs to provide electricity. See discussion 2.5.1.1 regarding stationary diesel ICEs and TAC emissions.~~

~~2.5.1.3 Cement Manufacturing~~

~~Cement manufactured in a cement kiln using a pyroprocess or high temperature reactor that is constructed along a longitudinal axis with segmented rotating cylinders whose connected length is anywhere from 50 to 200 yards in length. The pyroprocess in the kiln consists of three phases during which clinker is produced from raw materials undergoing physical changes and chemical reactions. The first phase in the kiln, the drying and pre-heating zone, operates at a temperature between 1,000 °F and 1,600 °F and evaporates any remaining water in the raw mix of materials entering the kiln. The second phase, the calcining zone, operates at a temperature between 1,600 °F and 1,800 °F and converts the calcium carbonate from the limestone in the kiln feed into calcium oxide and releases~~ ~~CO_2~~~~. During the third phase, the burning zone operates on average at 2,200 °F to 2,700 °F (though the flame temperature can at times exceed 3,400 °F) during which several reactions and side reactions occur. As the materials move towards the discharge end, the temperature drops and eventually clinker nodules form and volatile constituents, such as sodium, potassium, chlorides, and sulfates, evaporate. The red-hot clinker exits the kiln, is cooled in the clinker cooler, passes through a crusher and is conveyed to storage.~~

~~Stack emissions: As indicated above cement manufacturing occurs at high temperatures using several combustion fuels. Fuels that have been used for primary firing include coal, petroleum coke, heavy fuel oil, natural gas, landfill off-gas and oil refinery flare gas. High carbon fuels such as coal are preferred for kiln firing, because they yield a luminous flame. The clinker is brought to its peak temperature mainly by radiant heat transfer, and a bright (i.e. high emissivity) and hot flame is essential for this. Combustion emissions are exhausted through the kiln's stack. The primary TAC emission from cement manufacturing is hexavalent chromium, also referred to as chromium VI.~~

~~Fugitive Dust: Relative to cement manufacturing, fugitive dust is wind-driven particulate matter emissions from any disturbed surface work area that are generated by wind action alone. The process of making cement begins with the acquisition of raw materials, predominantly limestone rock (calcium carbonate) and clay, which exist naturally in rocks and sediment on the earth's surface. These and other materials used to manufacture cement are typically mined at nearby quarries and comprise "raw mix." The raw mix is refined by a series of mechanical crushing and grinding operations to segregate and eventually reduce the size of each component to 0.75 inch or smaller before being conveyed to storage. If the ground materials are stored in piles onsite, local windy conditions may produce fugitive hexavalent chromium emissions.~~

~~2.5.1.4 Chemical Plants~~

~~A chemical plant is any industrial facility engaged in producing chemicals, and/or manufacturing products by chemical processes. The general objective of a chemical plant~~

~~is to create new material wealth via the chemical or biological transformation and or separation of materials. Chemical plants often use specialized equipment, units, and/or technology used in the manufacturing process. Chemical plants may include, but are not limited to the manufacture of industrial inorganic and organic chemicals; plastic and synthetic resins, synthetic rubber, synthetic fibers; drugs; soap, detergents and cleaning preparations, perfumes, cosmetics and other toilet preparations; paints, varnishes, lacquers, enamels and allied products; agricultural chemicals; safflower and sunflower oil extracts; and re-refining. The primary types of equipment used at chemical plants include, but are not limited to: crushers, mixing tanks, compactors, heaters, etc.~~

~~Stack emissions: Mixing equipment that combines chemicals to produce inorganic and organic chemicals; plastic and synthetic resins, synthetic rubber, synthetic and other man-made fibers, etc., may be vented to an exhaust stack. Emissions from chemical plants may include: formaldehyde (used as a raw material in resin, plastic, leather, paper and fiber manufacturing); carbon tetrachloride (used as a cleaner), and sulfuric acid (from sulfur recovery plants).~~

~~Fugitive Emissions: Fugitive emissions at chemical plants include particulate emissions from chemical handling and uncontrolled product crushing or compressing and emissions that are released through windows, doors, vents, and other general building ventilation or exhaust systems.~~

~~2.5.1.5 Crematoria~~

~~Cremation is the combustion, vaporization and oxidation of cadavers to gases, ashes and mineral fragments retaining the appearance of dry bone. Cremation occurs in a crematory that is housed within a crematorium and comprises one or more furnaces. A cremator is an industrial furnace that is able to generate temperatures of 1,600 °F to 1,800 °F to ensure disintegration of the corpse. The chamber where the body is placed is called a retort and is lined with heat-resistant refractory bricks. Refractory bricks are designed in several layers. The outermost layer is usually simply an insulation material, e.g., mineral wool. Inside is typically a layer of insulation brick, mostly calcium silicate in nature. Modern crematoria fuels may include oil, natural gas, and propane.~~

~~Stack Emissions: Combustion emissions from the furnace are vented to an exhaust stack and then may be released to the atmosphere. Mercury from dental amalgam fillings can be emitted through the exhaust stack during the cremation process. Metals, such as chromium VI, arsenic and cadmium, are also found in crematory exhaust.~~

~~2.5.1.6 Landfills~~

~~Landfills, also called sanitary landfills, are locations where non-hazardous waste is deposited, spread in layers, compacted, and covered with earth at the end of each working day. Modern landfills typically include a bottom liner that separates and prevents the buried waste from coming into contact with underlying natural soils and groundwater. The bottom of each landfill is typically designed so that the bottom surface of the landfill is~~

~~sloped to a low point, called a sump. This is where any liquids that are trapped inside the landfill known in the waste industry as leachate are collected and removed from the landfill. The leachate collection system typically consists of a series of perforated pipes, gravel packs and a layer of sand or gravel placed in the bottom of the landfill. Landfill cells are the area in a landfill that have been constructed and approved for disposal of waste each day. Waste material is prepared by placing it in layers or lifts where the waste is then compacted and shredded by heavy landfill compaction machinery. Waste that is placed in a cell is covered daily with either six inches of compacted soil or an alternative daily cover, such as foam or a flame-retardant fiber material.~~

~~Fugitive Emissions: Bacteria in the landfill waste break down the trash in the absence of oxygen. This process produces landfill gas, which is approximately 50 percent methane. Landfill gas is collected in a series of pipes that are embedded within the landfill waste materials. This gas, once collected, is typically control-burned. Fugitive landfill TAC emissions may include vinyl chloride, benzene, hydrogen sulfide, and acrylonitrile.~~

~~Stationary Diesel ICEs: Because landfills are often located in remote areas away from population centers, they might not be served by electricity power lines from the local electric utility. Stationary diesel ICEs are often used to provide electricity to landfills that may not have access to electricity sources. If electricity is available, they may be used as a backup source of electricity in the event of a power outage. Finally, diesel ICEs may be used to pump liquids, such as leachate, to storage or treatment facilities. See discussion 2.5.1.1 regarding stationary diesel ICEs and TAC emissions.~~

~~2.5.1.7 Foundries~~

~~Foundries are industrial operations that create metal products by heat treating and shaping metals. Forging operations include operation of an oven in which metal is heated until it is malleable; it may then undergo hardening, annealing, tempering stamping, pressing, extruding, hammering, and quenching. Foundries operate using a furnace in which scrap metal, ingots, and/or other forms of metal are charged, melted, and tapped. Metals are melted using a furnace. Types of furnaces include, but are not limited to, cupola, electric arc, pot, induction, blast, crucible, sweat, and reverberatory furnaces. Once a cast metal part has been shaken out and cooled, it undergoes the finishing operations, which address imperfections and assembly in preparation of the final product for the customer. Finishing operations includes shot blasting, grinding, and welding.~~

~~Fugitive Emissions: Fugitive emissions at foundries include mold vent gases, equipment leaks, particulate emissions from metal handling and uncontrolled product finishing, and emissions that are released through windows, doors, vents, and other general building ventilation or exhaust systems. TAC emissions from foundries may include dioxins, PAHs, and heavy metals.~~

~~2.5.1.8 Sewage Treatment Facilities~~

~~Sewage treatment is the process of removing contaminants from wastewater, primarily from household sewage. The process includes physical, chemical, and biological processes to remove these contaminants and produce environmentally safe treated wastewater (or treated effluent). A by-product of sewage treatment is usually a semi-solid waste or slurry, called sewage sludge, that may be required to undergo further treatment before being suitable for disposal or land application.~~

~~The following bullet points provide brief summaries of the main steps in treating wastewater (Wikipedia, 2017).~~

- ~~*Pretreatment:* Pretreatment is a process that removes all materials that can be easily collected from the raw sewage before they damage or clog the pumps and sewage lines of primary treatment clarifiers. During pretreatment, the influent in sewage water passes through a bar screen to remove all large objects carried in the sewage stream, including, but not limited to: trash, tree limbs, leaves, branches, cans, rags, sticks, plastic packets, etc. This process is most commonly done with an automated mechanically raked bar screen in modern plants serving large populations, while in smaller or less modern plants, a manually cleaned screen may be used.~~
- ~~*Primary Treatment:* Primary treatment consists of temporarily holding the sewage in a quiescent basin where heavy solids can settle to the bottom while oil, grease, and lighter solids float to the surface. The settled and floating materials are removed and the remaining liquid may be discharged or subjected to secondary treatment. In the primary sedimentation stage, sewage flows through large tanks, commonly called "pre-settling basins," "primary sedimentation tanks," or "primary clarifiers." The tanks are used to settle sludge while grease and oils rise to the surface and are skimmed off. Primary settling tanks are usually equipped with mechanically driven scrapers that continually drive the collected sludge towards a hopper in the base of the tank where it is pumped to sludge treatment facilities.~~
- ~~*Secondary Treatment:* Secondary treatment removes dissolved and suspended biological matter. The majority of municipal plants treat the settled sewage liquor using aerobic biological processes. To be effective, the bacteria and protozoa require both oxygen and food to live. These micro-organisms consume biodegradable soluble organic contaminants (e.g. sugars, fats, organic short-chain carbon molecules, etc.) and bind much of the less soluble fractions into floc. Secondary treatment systems are classified as fixed film or suspended-film growth systems. Fixed-film or attached growth systems include, but are not limited to: trickling filters, bio-towers, and rotating biological contactors where the biomass grows on media and the sewage passes over its surface. Suspended-growth systems include activated sludge, where the biomass is mixed with the sewage and can be operated in a smaller space than trickling filters that treat the same amount of water. Secondary treatment may require a separation process to remove the micro-organisms from the treated water prior to discharge or tertiary treatment.~~

- ~~*Tertiary Treatment:* Tertiary treatment is sometimes defined as anything more than primary and secondary treatment to allow release into a sensitive or fragile ecosystem (estuaries, low-flow rivers, etc.). Treated water is sometimes disinfected chemically or physically (for example, by lagoons and microfiltration) prior to discharge into a stream, river, bay, lagoon or wetland. If it is sufficiently clean, it can also be used for groundwater recharge or agricultural purposes.~~

~~Fugitive Emissions: Wastewater treatment units open to the atmosphere have the potential to generate fugitive emissions. For example, the equalization basin, one of the first parts of the wastewater treatment process, regulates the wastewater flow and pollutant compositions to the remaining treatment units. The equalization basin also typically provides a large area for wastewater contact with ambient air. For this reason, fugitive emissions may be relatively high from this unit. Wastewater then is typically sent to the clarifier using a lift station, which may also be open to the ambient air. Suspended solids are removed in the clarifier and the wastewater then flows, again using a lift station, to the aeration basin where microorganisms act on the organic constituents. The lift station, clarifier, and aeration basin may be open to the atmosphere. Wastewater leaving the aeration basin normally flows through a secondary clarifier for solids removal before it is discharged from the facility (STAPPA/ALAPCO, 1997). The secondary clarifier is also likely to be open to the atmosphere. Fugitive TAC emissions from wastewater treatment include hydrogen sulfide and toxic organic compounds.~~

~~Stack Emissions: Sludge that is separated from the wastewater is sent to the sludge digesters. Sludge digesters are used to treat organic sludges produced from various treatment operations. The two main types of sludge digesters are anaerobic and aerobic. Anaerobic digesters aerate the sludge for an extended period of time in an open, unheated tank using conventional air diffusers or surface aeration equipment. In aerobic digestion, the sludge is aerated for an extended period of time in an open, unheated tank using conventional air diffusers or surface aeration equipment. The digestion process may produce a variety of emissions, including methane, which may be sent to an air pollution control unit or combusted. Energy recovery units, which are often used to control methane, produce formaldehyde and benzene during combustion of digester gas and natural gas. The sludge is then dewatered using a dryer. Stack emissions may occur from the combustion of digester gas or from the dryer. TAC emissions from wastewater treatment systems' exhaust stacks include hydrogen sulfide.~~

~~Incineration of sludge tends to maximize heavy metal concentrations in the remaining solid ash requiring disposal; but the option of returning wet scrubber effluent to the sewage treatment process may reduce air emissions by increasing concentrations of dissolved salts in sewage treatment plant effluent. Risk due to metal emissions can be mitigated using wet scrubbers or afterburning and increasing stack heights.~~

~~2.5.1.9 Power Plants~~

~~Power plants, also referred to as generating stations or generating plants, are industrial facilities for the generation of electric power. Most power plants contain one or more pieces of equipment used to generate electrical power. The most common equipment used to generate electricity at power plants are gas turbines and/or boilers.~~

~~A gas turbine is an internal-combustion engine consisting of at least a compressor, a combustion chamber, and a turbine. The compressor draws air into the engine, pressurizes it, and feeds it to the combustion chamber. The combustion system is typically made up of a ring of fuel injectors that inject a steady stream of fuel into combustion chambers where it mixes with the air. The combustion produces a high temperature, producing a high-pressure gas stream that enters and expands through the turbine section. The turbine is an intricate array of alternate stationary and rotating aerofoil-section blades. As hot combustion gas expands through the turbine, it spins the rotating blades. The rotating blades perform a dual function: they drive the compressor to draw more pressurized air into the combustion section, and they spin a generator to produce electricity (U.S. Dept., of Energy).~~

~~A boiler is a piece of combustion equipment fired with liquid and/or gaseous fuel, which is primarily used to produce steam. Boilers used to generate electricity are generally less efficient than gas turbines. All boiler designs share a number of common elements. Utility boilers are typically watertube boilers where combustion takes place in an enclosed furnace and heat is transferred from the furnace to water in tubes. In the furnace itself, heat is transferred by radiation from the combustion gases to tubes lining the walls. As gases cool and leave the furnace, the primary heat transfer mechanism becomes convection. A boiler is designed to have specific fixed temperature zones for optimum heat transfer to the watertubes; modification of these designs will affect boiler efficiency. For utility boilers, various types of burners are used to combust the fuel (STAPPA/ALAPCO, 1994).~~

~~Stack Emissions: In the case of both gas turbines and boilers, combustion emissions are vented to an exhaust stack and then released to the atmosphere. However, before the exhaust is released to the atmosphere, it is vented to a NOx emission control device to reduce NOx emissions pursuant to Rule 9-9 for gas turbines and Rule 9-10 for power generating boilers. Depending on the combustion fuel used, gas turbines and utility boilers have the potential to emit formaldehyde and benzene if they are not completely combusted in the boiler or gas turbine. In the event of an emergency, Rules 9-9 and 9-11 allow the use of non-gaseous fuels for gas turbines and electric utility boilers, respectively, which has the potential to produce diesel PM emissions. NOx control using selective catalytic reduction (SCR) uses a reducing agent, typically ammonia, to reduce NOx to nitrogen and water. Not all of the ammonia reacts with the NOx molecules and so is vented to the atmosphere, referred to as ammonia slip.~~

~~2.5.1.10 Gasoline Stations~~

~~Gasoline stations include any stationary operation that dispenses gasoline directly into the fuel tanks of motor vehicles. Gasoline stations are treated as a single source which includes all necessary equipment for the exclusive use of the facility, such as pumps, pump nozzles,~~

~~dispensers, vapor return lines, plumbing and storage tanks. VOC emissions from gasoline stations are regulated by Rule 8-7.~~

~~Fugitive Emissions: Fugitive emissions at gasoline stations may occur when gasoline is dispensed into motor vehicle fuel tanks or storage tanks or may occur as a result of leaks in vapor return lines, storage tanks, dispensers, etc. Fugitive TACs from gasoline stations include benzene, ethyl benzene, hexane, toluene and xylene.~~

~~2.5.1.1 Military Facilities~~

~~A military facility is a facility servicing military forces and, in the United States, under the jurisdiction of the Secretary of the Military Department. Types of military bases include, but are not limited to, the following: arsenal or armory, which is a military site were arms, ammunition, and other military equipment are stored; a military post is an installation at which a body of troops is stationed; military headquarters is the military installation from which a commander performs the functions of command; etc., (U.S. Dept. of Defense, 2005).~~

~~Stationary Diesel ICEs: Because military facilities or their operations may be located in remote areas away from population centers, they might not be served by electricity power lines from the local electric utility. Stationary diesel ICEs may be used to provide electricity to military facilities that may not have access to electricity sources; if electricity is available, may be used as a backup source of electricity in the event of a power outage. See discussion 2.5.1.1 regarding stationary diesel ICEs and TAC emissions.~~

~~2.5.1.12 Manufacturing Facilities~~

~~Facilities most anticipated to be affected by draft Rule 11-18 are described in Subsections 2.5.1.1 through 2.5.1.11. However, to ensure that other sources of TAC emissions are not overlooked, Air District staff has identified the manufacturing facilities category as a catch-all category. Sources that may be included in this category include, but are not limited to: colleges and universities; airline operations; grocery or convenience stores that refrigerate fresh or frozen foods; food preparation facilities that require chillers or refrigeration, e.g., ice cream manufacturing, breweries, frozen food packaging; research laboratories, etc.~~

~~Stationary Diesel ICEs: Manufacturing facilities would likely need backup stationary diesel ICEs to provide power in the event of electricity blackouts to maintain computers, laboratory experiments, refrigeration so foods do not spoil, etc. See discussion in Subsection 2.5.1.1 regarding stationary diesel ICEs and TAC emissions.~~

~~2.5.2 Control Technologies that May Be Used to Comply with Regulation 11, Rule 18~~

~~Draft Rule 11-18 would apply to existing facilities and would require preparation of a risk reduction plan for those facilities that pose a health risk in excess of the proposed risk action levels, 10 per million cancer risk level or a 1.0 hazard index. If a facility is identified that exceeds the risk action levels the facility must either: implement an Air District-approved risk reduction plan that details how the facility would reduce its health risk below the risk action level in the specified timeframe or demonstrate to the Air District that all significant sources of risk are controlled with TBARCT.~~

~~To comply with the risk action levels for those affected facilities that are required to prepare a risk reduction plan, operators could reduce operations or install TBARCT equipment. Table 2.5-2 identifies the types of facilities affected by the draft rule, the primary sources of TAC emissions, and the most likely types of control technologies that would be used to reduce risk. The following subsections briefly describe the most likely types of control technologies that would be used to comply with the risk reduction requirements of draft Rule 11-18.~~

~~Table 2.5-2~~
~~Summary of Toxic Air Contaminant Control Equipment~~

~~Facility~~	~~Sources~~	~~Control Equipment~~
~~Refineries~~	~~Fugitive Emissions~~	~~Establish requirements for more frequent inspections, require replacement of non-repairable valves, flanges, pressure relief devices, etc. (similar to or more stringent than Rule 8-19)~~
	~~Stack Emissions~~	~~Baghouse with high efficiency filter, LoTOx™ with WGS, UltraCat~~
	~~Diesel Engines~~	~~Require emission limits based on the most efficient DPF, DOC (similar to or more stringent than Rule 11-17)~~
	~~Cooling Towers~~	~~Tighten requirements in Rule 11-10 for more frequent inspections and shorten time period to comply once leak is detected (similar to or more stringent than Rule 11-10[a])~~
	~~Wastewater Treatment Operations~~	~~Require high collection efficiency of the organic compound recovery system, shorten period between inspections of wastewater collection systems (similar to or more stringent than Rule 8-18)~~
~~Data Centers~~	~~Stationary Diesel Engines~~	~~Require emission limits based on the most efficient DPF, DOC (similar to or more stringent than Rule 11-17)~~
~~Cement Manufacturing~~	~~Stack Emissions~~	~~Require baghouses with high efficiency filters (similar to or more stringent than Rule 9-13)~~
	~~Fugitive Emissions~~	~~Require enclosed conveyors and storage piles, rumble grates, conveyor skirting, dust curtains, road paving, reducing traffic speed and volume (similar to or more stringent than Rule 9-13)~~
~~Chemical Plants~~	~~Stack Emissions~~	~~Wet gas scrubber~~
	~~Fugitive Emissions~~	~~Establish requirements for more frequent inspections, require replacement of non-repairable valves, flanges,~~

~~Facility~~	~~Sources~~	~~Control Equipment~~
		~~pressure relief devices, etc. (similar to or more stringent than Rule 8-22), baghouse with high efficiency filter~~
~~Crematoria~~	~~Stack Emissions~~	~~Baghouse with high efficiency filter~~
~~Landfills~~	~~Fugitive Emissions~~	~~Gas collection and control systems under continuous operation and under negative pressure at all times, enclosed thermal oxidizer with a destruction efficiency of 99%~~
	~~Diesel Engines~~	~~Require emission limits based on the most efficient DPF, DOC, (similar to or more stringent than Rule 11-17)~~
~~Foundries~~	~~Fugitive Emissions~~	~~Baghouse with high efficiency filter~~
~~Sewage Treatment Facilities~~	~~Fugitive Emission~~	~~Enclose piping, process units, settling basins, lift stations, etc.~~
	~~Stack Emissions~~	~~Steam stripping and air stripping off-gases vented to a control or collection device, such as a combustion device (thermal oxidizer) or gas-phase carbon adsorber. Wet gas scrubbers and afterburners to control heavy metals, acid gas.~~
~~Power Plants~~	~~Stack Emissions~~	~~Baghouse with high efficiency filter, LoTOx™ with WGS, UltrCat~~
~~Gasoline Stations~~	~~Fugitive Emissions~~	~~Establish requirements such as removing exemptions on various equipment or operations (similar to, or more stringent than Rule 8-7~~
~~Military Facilities~~	~~Diesel Engines~~	~~Require emission limits based on the most efficient DPF, DOC, (similar to or more stringent than Rule 11-17)~~
~~Manufacturing~~	~~Diesel Engines~~	~~Require emission limits based on the most efficient DPF, DOC, (similar to or more stringent than Rule 11-17)~~

~~[a] Effective July 1, 2016, Rule 11-10 prohibited use of chromium chemicals in all cooling towers in the district.~~

~~DOC = diesel oxidation catalyst, DPF = diesel particulate filter~~

~~2.5.2.1 Baghouses with High Efficiency Filters~~

~~A baghouse is an air filtration control device designed to remove particulate matter emissions (both PM_{10} and $PM_{2.5}$) from an exhaust gas stream using filter bags, cartridge-type filters, or envelope-type filters. A baghouse consists of the following components: filter medium and support, filter cleaning device, collection hopper, shell, and fan. Most baghouse designs employ long cylindrical tubes (bags) that contain various types of fabric as the filtering medium. When particulate-laden air flows to the inlet of a baghouse, particulates are filtered through the filter bags inside the baghouse and filtered air flows from the outlet of the baghouse. Particulate layers (dust cakes) deposited on the surface of the bags need to be cleaned periodically to prevent excessive increase of pressure drops across the baghouse, which may lead to bag leak resulting in failure of proper baghouse function. Baghouses are generally not used with catalytic cracking units because of the space required and because of the pressure drop they cause in the flue gas stream (STAPPA/ALAPCO, 2006).~~

~~The bag material or fabric media is an important part of baghouse design and selection, as it determines the life and effectiveness of the filter bag. Fabric filter media must be compatible both physically and chemically with the gas stream and system conditions. Baghouse filters with polytetrafluoroethylene (PTFE) (also known by the brand name Teflon®) membrane generally have higher control efficiencies than other filter constructions in many applications. Independent testing conducted under the EPA's Environmental Technology Verification (ETV) program has verified that one of the most efficient filters is PTFE membrane filters, which is capable of ultra-high control efficiencies. Tests of PTFE filter bags from several different manufacturers showed particulate matter control efficiencies of 99 to 99.9 percent for particle sizes down to 1.0 or 2.0 µm to less than 1.0 µm when properly operated and maintained (U.S. EPA, 1998). Among its many useful properties, PTFE is hydrophobic, meaning it repels water. Additionally, it has a very low coefficient of friction of 0.05 – 0.10 (meaning substances have a hard time sticking to it and are easily removed) and has a high melting point of approximately 617 °F (325°C).~~

~~Because of the microporous nature of PTFE, air-to-cloth ratios for these applications are lower than with conventional fabrics, requiring more collector area for a given volume flow rate of gas at a higher relative pressure drop. The current trend in bag cleaning is the pulsejet technology, where tubular bags are supported from the inside by metal wire frames. Gas flows across the fabric from the outside inward, exiting at the top of the bags. Periodically, a blast of compressed air from a fixed nozzle located inside the wire frame causes the bag to inflate outward, thus knocking the accumulated dust off the bag exterior and into the baghouse hopper, ready for collection and disposal.~~

~~2.5.2.2 Carbon Adsorber~~

~~Adsorption is a process by which VOCs are retained on the surface of granular solids. The solid adsorbent particles are highly porous and have very large surface-to-volume ratios. Gas molecules penetrate the pores of the adsorbent and contact the large surface area available for adsorption. Activated carbon is the most common adsorbent for VOC removal. Advantages of carbon adsorption include the recovery of a relatively pure product for recycle and reuse and a high removal efficiency with low inlet concentrations. In addition, if a process stream is already available onsite additional fuel costs are low, the main energy requirement being electrical power to run fan motors.~~

~~Fixed, moving, or fluidized-bed regenerative carbon adsorption systems operate in two modes, adsorption and desorption. Adsorption is rapid and removes from 50 to 99 percent of VOCs in the air stream, depending on their composition, concentration, temperature, and bed characteristics. Well-designed and operated systems, however, can usually achieve removal efficiencies in the 90 to 99 percent range. Eventually, the adsorbent becomes saturated with the vapors and system efficiency drops. At this point (called "breakthrough," since the contaminants "break through" the saturated bed), the VOC contaminated stream is directed to another bed containing regenerated adsorbent, and the saturated bed is then regenerated. Although it is possible to operate a non-regenerative~~

~~adsorption system (i.e., the saturated carbon is disposed of and fresh carbon is placed into the bed), most applications, especially those with high VOC loadings, are regenerative.~~

~~2.5.2.3 Diesel Oxidation Catalyst~~

~~Oxidation catalysts have two simultaneous tasks: 1) oxidation of carbon monoxide to CO_2 and 2) oxidation of unburned hydrocarbons (unburned and partially-burned fuel) to CO_2 and water. An oxidation catalyst contains materials (generally precious metals such as platinum or palladium) that promote oxidation reactions between oxygen, CO, and VOC to produce CO_2 and water vapor. These reactions occur when exhaust at the proper temperature and containing sufficient oxygen passes through the catalyst. Depending on the catalyst formulation, an oxidation catalyst may obtain reductions at temperatures as low as 300 ºF to 400 ºF, although minimum temperatures in the 600 ºF to 700 ºF range are generally required to achieve maximum reductions. The catalyst will maintain adequate performance at temperatures typically as high as 1,350 ºF before problems with physical degradation of the catalyst occur. In the case of rich-burn engines, where the exhaust does not contain enough oxygen to fully oxidize the CO and VOC in the exhaust, air can be injected into the exhaust upstream of the catalyst. Diesel oxidation catalysts are widely used on lean-burn engines to reduce hydrocarbon and carbon monoxide emissions. The oxidation catalyst is a corrugated base metal substrate with an alumina wash coat loaded with precious metals such as platinum. The alumina is porous allowing for large surface areas to promote oxidation of any unreacted CO and hydrocarbons with oxygen remaining in the exhaust gas. Most oxidation catalysts can be retrofitted onto the engine without disruption of the existing design configuration.~~

~~2.5.2.4 Diesel Particulate Filter~~

~~To further reduce DPM emissions from stationary diesel ICEs, the ICEs could be retrofitted with DPFs. DPFs allow exhaust gases to pass through the filter medium, but trap DPM before it is released to the atmosphere. Depending on an engine's baseline emissions and emission test method or duty cycle, DPFs can achieve DPM emission reduction efficiencies from the exhaust of 70 to 90 percent. In addition, DPFs can reduce HC emissions by 95 percent and CO emissions by 90 percent. Limited test data indicate that DPFs can also reduce NOx emissions by six to ten percent.~~

~~Particulates build up in the traps over time and must be removed by burning because they are mainly carbon. Some designs use electrical resistance heaters to raise the temperature in the trap high enough to burn off the particulates. Others have a burner built into the trap. Currently, the most common regeneration scheme employs "post injection," in which a small amount of fuel is injected into the cylinder late in the expansion stroke. This fuel then burns in the exhaust system, raising the trap temperature to the point where the accumulated particulate matter is readily burned away.~~

~~There are both active DPFs and passive DPFs. Active DPFs use heat generated by means other than exhaust gases (e.g., electricity, fuel burners, and additional fuel injection to~~

~~increase exhaust gas temperatures) to assist in the regeneration process. Passive DPFs, which do not require an external heat source to regenerate, incorporate a catalytic material, typically a platinum group metal, to assist in oxidizing trapped diesel PM.~~

~~2.5.2.5 Thermal Oxidizers~~

~~There are three main categories of thermal oxidizers that could be used to control volatile TAC emissions: afterburners with no heat recovery, thermal oxidizers with recuperative heat recovery, and highly efficient regenerative heat recovery oxidizers. Afterburners with no heat recovery are the most likely types of thermal oxidizer anticipated to control TAC emissions. Thermal oxidizers, or thermal incinerators, are combustion devices that control volatile TAC emissions by combusting them to~~ ~~CO_2~~ ~~and water.~~

~~Three main factors contributing to the effectiveness of thermal oxidizers are temperature, residence time, and turbulence. The temperature needs to be high enough to ignite the waste gas. Most organic compounds ignite at the temperature between 1,094 °F (590 °C) and 1,202 °F (650 °C). To ensure destruction of hazardous gases, most basic oxidizers are operated at much higher temperature levels. Residence time is important for ensuring that there is enough time for the combustion reaction to occur. The turbulence factor is the mixture of combustion air with the hazardous gases.~~

~~2.5.2.6 UltraCat~~

~~UltraCat is a commercially available multi-pollutant control technology designed to remove NOx and other pollutants such as~~ ~~SO_2~~~~, PM, hydrochloric acid, dioxins, and TACs such as mercury in low temperature applications. UltraCat technology is comprised of filter tubes which are made of fibrous ceramic materials embedded with proprietary catalysts. The optimal operating temperature range of an UltraCat system is approximately 350 °F to 750 °F. To achieve a NOx removal efficiency of approximately 95 percent, aqueous ammonia is injected upstream of the UltraCat filters. In addition, to remove~~ ~~SO_2~~~~, HCl, and other acid gases with a removal efficiency ranging from 90 percent to 98 percent, dry sorbent such as hydrated lime, sodium bicarbonate or trona is also injected upstream of the UltraCat filters. UltraCat is also capable of controlling particulates to a level of 0.001 grains per standard cubic foot of dry gas (dscf).~~

~~The UltraCat filters are arranged in a baghouse configuration with a low pressure drop such as five inches water column (in water) across the system. The UltraCat system is equipped with a reverse pulse jet cleaning action that back flushes the filters with air and inert gas to dislodge the PM deposited on the outside of the filter tubes. Depending on the loading, catalytic filter tubes need to be replaced every five to 10 years (Tri-Mer Corp., 2013).~~

~~2.5.2.7 Wet Gas Scrubber~~

~~In wet scrubbing processes, liquid or solid particles are removed from a gas stream by transferring them to a liquid. This addresses only wet scrubbers for control of particulate matter. The liquid most commonly used is water. A wet scrubber's particulate collection~~

~~efficiency is directly related to the amount of energy expended in contacting the gas stream with the scrubber liquid. Most wet scrubbing systems operate with particulate collection efficiencies over 95 percent (U.S. EPA, 2017).~~

~~There are three energy usage levels for wet scrubbers. A low energy wet scrubber is capable of efficiently removing particles greater than about 5-10 micrometers in diameter. A medium energy scrubber is capable of removing micrometer-sized particles, but is not very efficient on sub-micrometer particles. A high-energy scrubber is able to remove sub-micrometer particles.~~

~~A spray tower scrubber is a low energy scrubber and is the simplest wet scrubber used for particulate control. It consists of an open vessel with one or more sets of spray nozzles to distribute the scrubbing liquid. Typically, the gas stream enters at the bottom and passes upward through the sprays. The particles are collected when they impact the droplets. This is referred to as counter-current operation. Spray towers can also be operated in a cross-current arrangement. In cross-current scrubbers, the gas flow is horizontal and the liquid sprays flow downward. Cross-current spray towers are not usually as efficient as counter-current units.~~

~~The most common high energy wet scrubber is the venturi, although it can also be operated as a medium energy scrubber. In a fixed-throat venturi, the gas stream enters a converging section where it is accelerated toward the throat section. In the throat section, the high-velocity gas stream strikes liquid streams that are injected at right angles to the gas flow, shattering the liquid into small drops. The particles are collected when they impact the slower moving drops. Following the throat section, the gas stream passes through a diverging section that reduces the velocity.~~

~~All wet scrubber designs incorporate mist eliminators or entrainment separators to remove entrained droplets. The process of contacting the gas and liquid streams results in entrained droplets, which contain the contaminants or particulate matter. The most common mist eliminators are chevrons, mesh pads, and cyclones. Chevrons are simply zig-zag baffles that cause the gas stream to turn several times as it passes through the mist eliminator. The liquid droplets are collected on the blades of the chevron and drain back into the scrubber. Mesh pads are made from interlaced fibers that serve as the collection area. A cyclone is typically used for the small droplets generated in a venturi scrubber. The gas stream exiting the venturi enters the bottom of a vertical cylinder tangentially. The droplets are removed by centrifugal force as the gas stream spirals upward to the outlet.~~

2.5.1 Refinery Equipment Potentially Affected by Draft Rule 12-16

Draft Rule 12-16 would set emission limits for each affected refinery and the three affected support facilities. As noted in the project description above, the rule would ~~then~~ establish an emission limit which is seven percent higher than the highest emission rate during the baseline period. Pollutants subject to the facility emission limits include GHGs; particulate matter, both $PM_{2.5}$ and PM_{10}; NOx; and SO_2.

According to the Staff Report for the draft rule, the emissions limits established for each facility do not appear to inhibit refining capacity, since typical annual average utilization is 80 – 87 percent, and the emissions limits appear to establish production capacity limits at approximately 89 – 93 percent utilization (BAAQMD, 2016b). That is, the caps in draft Rule 12-16 appear to be consistent with the current maximum production capability of the refineries. Given that the emission limits are consistent with the current production capacity; affected facility operators may not be required to install control equipment if crude oil throughput and, therefore, fuel consumption do not substantially increase.

If affected facilities exceed their emission limits or affected facility operators decide to increase crude oil throughput, to capture greater market share for example, then to remain in compliance with draft Rule 12-16 the most likely means of reducing $PM_{2.5}$, PM_{10}, NOx, or SO_2 emissions would be to further control emissions sources of these regulated pollutants at the affected facilities. The following sections and subsections identify the affected facilities' emissions sources that may be subject to draft Rule 12-16 and the most likely control technologies anticipated to be used for affected facilities and emissions sources.

It is currently unknown if any affected refineries would exceed any of the future facility-specific emission limits for $PM_{2.5}$, PM_{10}, NOx, or SO_2. However, some types of refinery equipment that emit $PM_{2.5}$, PM_{10}, NOx, or SO_2 can be identified (see Table 2.5-1). The sections below identify and briefly describe typical types of refinery equipment that emit $PM_{2.5}$, PM_{10}, NOx, or SO_2 and that would most likely be subject to further control, if required, as they tend to be the largest sources of emissions that may be affected by Rule 12-16. In some cases, refinery equipment may emit one pollutant or any combination of pollutants subject to Rule 12-16. Similarly, the most likely types of SO_2, $PM_{2.5}$, and NOx emission control technologies associated with the largest SO_2, $PM_{2.5}$ and NOx emission sources at an affected refinery or support facility can also be identified (see Table 2.5-1). In some cases, control equipment identified below may reduce one or more pollutants subject to the proposed project. Potential secondary impacts from the control equipment identified below have been further analyzed in Chapter 3.

TABLE 2.5-1
Control Technologies by Source Category and Pollutant

	Pollutant		
Equipment Type	SO_2	$PM_{2.5}$	NOx
Boiler	FGT	Baghouse; ESP	SCR
DCU	Compressor; SET	Compressor; SET	
Diesel ICE		DPF, DOC	
FCCU	WGS, SRA	Cyclone, ESP	SCR, LoTOx^{TM} with WGS
PCC	WGS	Baghouse	LoTOxTM with scrubber, UltraCat with WGS
Process Heater	FGT	Baghouse; ESP	SCR
SRU/TGU	WGS; SOC	WGS	SCR, LoTOx^{TM} with WGS,
Refinery Gas Turbine			SCR

DCU = Delayed Coking Unit; DOC = Diesel Oxidation Catalyst; DPF = Diesel Particulate Filter; ESP = Electrostatic Precipitator: ICE = Internal Combustion Engine; FGT = Flue Gas Treatment; FCCU = Fluid Catalytic Cracking Unit; LoTOx^{TM} = Low Temperature Oxidation, PCC = Petroleum Coke Calciner; SCR = Selective Catalytic Reduction, SOC = SOx Oxidation Catalyst; SRA = SOx Reducing Additives; SRU = Sulfur Recovery Unit; SET = Steam Ejector Technology; TGU = Tail Gas Unit; UltraCat, WGS = Wet Gas Scrubber;

2.5.1.1 Delayed Coking Unit (DCU) ($PM_{2.5}$ and GHGs)

Delayed coking is a petroleum refinery process that converts mostly heavy residual oils, also known as residuum or “resid” for short, from vacuum distillation towers into gasoline, light gas oil and heavy gas oil. Petroleum coke is a by-product of the coking process. The resid is fed into a fractionation tower and the bottom fraction (e.g., the heavy components of the resid), is passed through a heater as it makes its way to a coke drum under steam injection. The purpose of the steam injection is to delay coking or the solidification of the hot material until it reaches the drum, hence the name “delayed coker.” When heated to high temperatures, the heavy hydrocarbon chains break into smaller, lighter molecules that rise to the top of the coke drum as vapors that are routed back to the fractionation tower for more separation into gas, gasoline, and other higher value liquid products. Even after heating, the heavier components remain in the coke drum. Within approximately 30 minutes to one hour, the material left behind in the drum turns into, petroleum coke, a coal-like substance. At the end of the coking process, the drum is then vented to the atmosphere until the internal pressure of the drum equals ambient pressure. TAC emissions from the DCU primarily include heavy metals.

At the federal level, in 2008, the USEPA promulgated a regulation in Chapter 40, Part 60, Subpart Ja of the Code of Federal Regulations (40 CFR 60 Subpart Ja) - Standards of

Performance for Petroleum Refineries for Which Construction, Reconstruction or Modification Commenced after May 14, 2007, specifically applicable to DCU operations that establishes a vent limit of five pounds per square inch, gauge (psig) for coke drums at new or modified DCUs. By depressurizing the coke drum beyond the federal requirement, to two psig for example, for both new and existing DCUs $PM_{2.5}$, and sulfur as H_2S emission reductions can be achieved with the co-benefit of additional VOC and GHG (methane) emission reductions.

~~For a complete description of DCUs, refer to Subsection 2.5.2.1.~~

2.5.1.2 Diesel Internal Combustion Engines (ICEs) (NOx and PM)

Stationary diesel ICEs are often used to provide electricity in areas of a refinery that may not have access to electricity power lines from the local electric utility or other onsite sources of electricity, used as a backup source of electricity in the event of a power outage, or as a means of pumping liquids between different refinery equipment. Four-stroke cycle ICEs are more commonly used than two-stroke ICEs. Stationary diesel ICEs operate by drawing air into a cylinder and then injecting fuel after the air has been compressed. Stationary diesel ICEs rely on high temperature alone for ignition. Stationary diesel ICEs are often referred to as compression ignition engines because the high temperature is the result of compressing air above the piston as it travels upward. The power output of a diesel ICE is controlled by varying the amount of fuel injected into the air, thereby, varying the fuel-air ratio. The main advantage of using a diesel engine is its high thermal efficiency[2], which can exceed 50 percent. However, diesel ICE exhaust tends to be high in NOx and particulate emissions, both visible (smoke) and invisible. Diesel particulates were also classified as a TAC by CARB in in 1998.

~~For a complete description of diesel ICEs, refer to Subsection 2.5.2.1.~~

2.5.1.3 Fluid Catalytic Cracking Units (FCCUs) (SO_2, NOx, and $PM_{2.5}$)

An FCCU is a major source of SO_2, NOx, and $PM_{2.5}$ emissions at refineries. The purpose of an FCCU at a refinery is to convert or “crack” heavy oils (hydrocarbons), with the assistance of a catalyst, into gasoline and lighter petroleum products. Each FCCU consists of three main components: a reaction chamber, a catalyst regenerator and a fractionator. Crude enters the reaction chamber, where it is mixed with a catalyst, typically a fine powder, under high heat. A chemical reaction occurs that converts the heavy oil liquid into a cracked hydrocarbon vapor mixed with catalyst. The cracked hydrocarbon vapor is routed to a distillation column or fractionator for further separation into lighter hydrocarbon components. Eventually, the catalyst becomes inactive or spent and is regenerated, first by removing oil residue using steam stripping. The spent catalyst is then sent to the catalyst regenerator where hot air burns the coke layer off the surface of each

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[2] Thermal efficiency is defined as the amount of work produced by the engine divided by the amount of chemical energy in the fuel that can be released through combustion. This chemical energy is often referred to as net heating value or heat of combustion of the fuel.

catalyst particle to produce reactivated or regenerated catalyst. Subsequently, the regenerated catalyst is cycled back to the reaction chamber and mixed with more fresh heavy liquid oil feed.

The primary source of SO_2, NOx, and $PM_{2.5}$ emissions from the catalytic cracking process is the catalyst regenerator unit. (The waste heat from the regenerator unit also provides much of the heat required by the catalytic cracking process.) During the cracking process, coke is deposited on the surface of the catalyst, deactivating the material. The catalyst is regenerated by burning off the coke at high temperatures. The flue gas from the regenerator unit contains SO_2, $PM_{2.5}$, and catalyst fines. In addition, organic metals in heavy gas oils can be deposited on the coke formed in the FCCU. When the coke is burned in the regenerator unit, these metals then deposit onto the catalyst. A portion of this catalyst is emitted from the FCC as particulates containing these metal compounds.

Of the total NOx emissions that can be generated, there are two types of NOx formed during combustion: 1) thermal NOx; and, 2) fuel NOx. Thermal NOx is produced from the reaction between the nitrogen and oxygen in the combustion air at high temperatures while fuel NOx is formed from a reaction between the nitrogen already present in the fuel and the available oxygen in the combustion air. As the source of nitrogen in fuel is more prevalent in oil and coal, and is negligible in natural gas, the amount of fuel NOx generated is dependent on fuel type. Based on the preceding information, NOx emissions are generated during the combustion process in the catalyst regenerator unit.

~~2.5.1.4 Petroleum Coke Calciner (SO_2, NOx, and $PM_{2.5}$)~~

~~For a complete description of petroleum coke calciners, refer to Subsection 2.5.2.1.~~

2.5.1.4 Refinery Gas Turbines (NOx and GHGs)

Gas turbines are used in refineries to produce both electricity and steam. Refinery gas turbines are typically combined cycle units that use two work cycles from the same shaft operation. Refinery gas turbines also have an additional element of heat recovery from its exhaust gases to produce more power by way of a steam generator. Gas turbines can operate on both gaseous and liquid fuels. Gaseous fuels include natural gas, process gas, and refinery gas. Liquid fuels typically include diesel. The units in this category are cogenerating units that recover the useful energy from heat recovery for producing process steam. ~~For additional information on gas turbines, see Subsection 2.5.1.8~~

2.5.1.5 Refinery Process Heaters and Boilers (SO_2, NOx, and $PM_{2.5}$)

Refinery process heaters and boilers are major sources of SO_2, NOx, and $PM_{2.5}$ emissions at most refineries. Refinery process heaters and boilers are used extensively throughout various processes in refinery operations such as distillation, hydrotreating, fluid catalytic cracking, alkylation, reforming, and delayed coking. A process heater is an enclosed device in which solid, liquid or gaseous fuels are combusted for the purpose of heating a process material (e.g., crude oil). There are two basic types of process heaters: direct and indirect. Direct-fired systems place the combustion gases in direct contact with the process material. Indirect systems rely on tubing to separate the combustion gases from the process material.

Refinery boilers are used primarily for heating and separating hydrocarbon streams and, to a lesser extent, for producing electricity. Refinery process heaters and boilers are primarily fueled by refinery gas, one of several products generated at a refinery. In addition, most refinery process heaters and boilers are designed to also operate on natural gas. The combustion of fuel generates NOx, primarily "thermal" NOx with small contribution from "fuel" NOx.

When used for heating, the steam usually heats the petroleum indirectly in heat exchangers and returns to the boiler. In direct contact operations, the steam serves as a stripping medium or a process fluid. SO_2 and $PM_{2.5}$, emissions are typically created from the combustion of fuel that contains sulfur or sulfur compounds.

2.5.1.6 Sulfur Recovery Units and Tail Gas Units (SRU/TGUs) (SO_2 and NOx)

Refinery SRU/TGUs, including their incinerators, are classified as major sources of both NOx and SOx emissions. Because sulfur is a naturally occurring and undesirable component of crude oil, refineries employ a sulfur recovery system to maximize sulfur removal, which also generates SO_2 emissions. A typical sulfur removal or recovery system will include a sulfur recovery unit (e.g., Claus unit) followed by a tail gas treatment unit (e.g., amine treating) for maximum removal of hydrogen sulfide (H_2S). A Claus unit consists of a reactor, catalytic converters and condensers. Two chemical reactions occur in a Claus unit. The first reaction occurs in the reactor, where a portion of H_2S reacts with air to form SO_2, followed by a second reaction in the catalytic converters where SO_2 reacts with H_2S to form liquid elemental sulfur. The combination of two converters with two condensers in series will generally remove as much as 95 percent of the sulfur from the incoming acid gas.

To recover the remaining sulfur compounds after the final pass through the last condenser, the gas is sent to a tail gas treatment process such as a SCOT or Wellman-Lord where the sulfur compounds in the tail gas are converted to H_2S. The H_2S is absorbed by a solution of amine in the H_2S absorber, steam-stripped from the absorbent solution in the H_2S stripper, concentrated, and recycled to the front end of the sulfur recovery unit. The residual H_2S in the treated gas from the absorber is typically vented to a thermal oxidizer where it is oxidized to SO_2 before venting to the atmosphere.

The Wellman-Lord tail gas treatment process is a process where the sulfur compounds in the tail gas are first incinerated to oxidize to SO_2. After the incinerator, the tail gas enters a SO_2 absorber, where the SO_2 is absorbed in a sodium sulfite (Na_2SO_3) solution to form sodium bisulfite ($NaHSO_3$) and sodium pyrosulfate ($Na_2S_2O_5$). The absorbent, rich in SO_2, is then stripped and the SO_2 is recycled back to the beginning of the Claus unit. The residual sulfur compounds in the treated tail gas from the SO_2 absorber are then vented to a thermal oxidizer where they are oxidized to SO_2 before venting to the atmosphere.

The sulfur recovery unit typically includes a combustion chamber used to produce steam that selectively converts the H_2S in the presence of water vapor and excess oxygen to elemental sulfur only. The catalyst is also steam stripped to remove any hydrocarbons from it prior to regeneration by coke burnoff. The amine solution is regenerated by heating and the concentrated acid gas is then sent to a sulfur recovery plant located within the refinery. Because SRU/TGUs include one or more combustion processes, they have the potential to emit NOx emissions.

2.5.2 Applicable SO_2, NOx, $PM_{2.5}$ and PM_{10} Emissions Control Technologies Used at Refineries

If an affected refinery's SO_2, NOx, $PM_{2.5}$, and PM_{10} emissions exceed the refinery-wide annual emission limits in Regulation 12-16, the refinery operators must undertake emission reduction strategies, such as reducing throughput, or install air pollution control equipment. Table 2.5-1 above shows the most likely SO_2, NOx, $PM_{2.5}$, and PM_{10} control technologies expected to be used. Control technologies anticipated to be used to comply with draft Rule 12-16 are briefly described in the following subsections.

2.5.2.1 Baghouse

A baghouse is an air filtration control device designed to remove particulate matter emissions (both PM_{10} and $PM_{2.5}$) from an exhaust gas stream using filter bags, cartridge-type filters, or envelope-type filters. A baghouse consists of the following components: filter medium and support, filter cleaning device, collection hopper, shell, and fan. Most baghouse designs employ long cylindrical tubes (bags) that contain various types of fabric as the filtering medium. When particulate-laden air flows to the inlet of a baghouse, particulates are filtered through the filter bags inside the baghouse and filtered air flows from the outlet of the baghouse. Particulate layers (dust cakes) deposited on the surface of the bags need to be cleaned periodically to prevent excessive increase of pressure drops across the baghouse, which may lead to bag leak resulting in failure of proper baghouse function. Baghouses are generally not used with catalytic cracking units because of the space required and because of the pressure drop they cause in the flue gas stream (STAPPA/ALAPCO, 2006).

The bag material or fabric media is an important part of baghouse design and selection, as it determines the life and effectiveness of the filter bag. Fabric filter media must be compatible both physically and chemically with the gas stream and system conditions. Baghouse filters with polytetrafluoroethylene (PTFE) (also known by the brand name Teflon®) membrane generally have higher control efficiencies than other filter constructions in many applications. Independent testing conducted under the EPA's Environmental Technology Verification (ETV) program has verified that one of the most efficient filters is PTFE membrane filters, which is capable of ultra-high control efficiencies. Tests of PTFE filter bags from several different manufacturers showed particulate matter control efficiencies of 99 to 99.9 percent for particle sizes down to 1.0 or 2.0 µm to less than 1.0 µm when properly operated and maintained (U.S. EPA, 1998). Among its many useful properties, PTFE is hydrophobic, meaning it repels water. Additionally, it has a very low coefficient of friction of 0.05 – 0.10 (meaning substances have a hard time sticking to it and are easily removed) and has a high melting point of approximately 617 ºF (325°C).

Because of the microporous nature of PTFE, air-to-cloth ratios for these applications are lower than with conventional fabrics, requiring more collector area for a given volume flow rate of gas at a higher relative pressure drop. The current trend in bag cleaning is the pulsejet technology, where tubular bags are supported from the inside by metal wire frames. Gas flows across the fabric from the outside inward, exiting at the top of the bags. Periodically, a blast of compressed air from a fixed nozzle located inside the wire frame causes the bag to inflate outward, thus knocking the accumulated dust off the bag exterior and into the baghouse hopper, ready for collection and disposal.

~~For a complete description of baghouse in combination with high efficiency filters, refer to Subsection 2.5.2.1.~~

2.5.2.2 Cyclones

A cyclone, typically used as a pre-cleaner, does not have a blower mount to induce the particle-laden exhaust gas stream. Centrifugal force causes particles in the gas stream (both PM_{10} and $PM_{2.5}$) to enter the cyclone tangentially, which moves the particulate against the cyclone's cone wall. Air flows in a helical pattern, beginning at the top (wide end) of the cyclone and ending at the bottom (narrow) end before exiting the cyclone in a straight stream through the center of the cyclone and out the top. Larger (denser) particles in the rotating stream have too much inertia to follow the tight curve of the stream, and strike the outside wall, then fall to the bottom of the cyclone where they can be removed and sent to a storage unit. In a conical system, as the rotating flow moves towards the narrow end of the cyclone, the rotational radius of the stream is reduced, thus, separating smaller and smaller particles. The cyclone geometry, together with flow rate, defines the cut point of the cyclone. Cut point is the size of particle that will be removed from the stream with a 50 percent efficiency. Particles larger than the cut point will be removed out of the airstream with a greater efficiency and smaller particles with a lower efficiency. Greater centrifugal airflow improves particle separation and increases collection efficiency. Installing a cyclone is an attractive $PM_{2.5}$ control option because this technology is designed specifically for harsh, industrial environments and can operate in applications generating (both PM_{10} and $PM_{2.5}$) heavy particulate and high temperatures.

2.5.2.3 Depressurizing Delayed Coking Units

To minimize atmospheric venting at the end of the coking cycle, more of the vapors remaining in the head space above the coke in the drum can be sent to the blowdown system prior to opening the drum provided that the pressure in the drum head space is higher than that of the blowdown system. This pressure differential will cause the vapors to be routed to the blowdown system allowing more vapors to be captured. However, once the pressures equalize between the drum and the blowdown system, the only way to depressurize the drum to ambient pressure is to vent the remaining vapors, which primarily consist of steam (roughly 97 percent to 99 percent), from the drum to the atmosphere before drilling of the coke bed can commence. DCUs typically route the head space vapors in the coke drum to a blowdown system where recovered hydrocarbons are sent to the refinery fuel gas system.

One way to minimize emissions during coke drum venting would be to change the process by increasing the drum cooling time. Waiting longer before opening the coke drum would allow it to cool down further. Because refineries are comprised of multiple, sophisticated inter-connected and inter-dependent systems, any potential process changes could have unintended consequences that may cause other bottlenecks and throughput problems elsewhere. For these reasons, it is impractical and improbable that refinery operators would choose to allow additional time for the coke drums to cool, as other alternatives are available.

Another way to minimize emissions to atmosphere would be to increase the rate at which vapors are evacuated from the head space to the blowdown system. This can be accomplished by installing either compressor or steam ejector technology to create a pressure differential that would more quickly lower the drum's internal pressure (e.g., to less than two psig) as close as currently possible to ambient pressure (i.e., by definition, zero psig) before venting the drum to the atmosphere at the end of the coking cycle. Either of these devices could effectively serve as emissions control equipment by achieving lower pressures within the coke drum at the end of the coking cycle.

A compressor is a device used to compress gases and/or vapors with the support of an electric motor, internal combustion engine or steam. Compressors can handle a constant volume of gases with various discharge pressures. The volume of gas can be varied only by changing the motor speed or under-utilizing the design capacity of the unit. A sliding vane and oil flooded rotary screw compressors are commonly used for vapor recovery, but depending on final discharge routing, a reciprocating compressor may also be used.

A steam ejector is a simplified type of pumping device which, unlike a compressor, has no pistons, valves, rotors or other moving parts. A steam ejector consists of a nozzle which discharges a high-speed pressure steam jet across a suction chamber that is connected to the equipment to be evacuated (e.g., the coke drum head space). With a steam ejector in place, the vapors from the coke drum head space would be entrained in the steam from the steam ejector and carried into a venturi-shaped diffuser that would create a strong suction or vacuum effect that would allow for a quick evacuation of the remaining vapors in the coke drum. When comparing overall maintenance and operating costs, steam ejector technology typically has less maintenance requirements and associated costs than compressor technology.

2.5.2.4 Diesel Particulate Filters (DPFs)

To further reduce DPM emissions from stationary diesel ICEs, the ICEs could be retrofitted with DPFs. DPFs allow exhaust gases to pass through the filter medium, but trap DPM before it is released to the atmosphere. Depending on an engine's baseline emissions and emission test method or duty cycle, DPFs can achieve DPM emission reduction efficiencies from the exhaust of 70 to 90 percent. In addition, DPFs can reduce HC emissions by 95 percent and CO emissions by 90 percent. Limited test data indicate that DPFs can also reduce NOx emissions by six to ten percent.

Particulates build up in the traps over time and must be removed by burning because they are mainly carbon. Some designs use electrical resistance heaters to raise the temperature in the trap high enough to burn off the particulates. Others have a burner built into the trap. Currently, the most common regeneration scheme employs "post injection," in which a small amount of fuel is injected into the cylinder late in the expansion stroke. This fuel then burns in the exhaust system, raising the trap temperature to the point where the accumulated particulate matter is readily burned away.

There are both active DPFs and passive DPFs. Active DPFs use heat generated by means other than exhaust gases (e.g., electricity, fuel burners, and additional fuel injection to increase exhaust gas temperatures) to assist in the regeneration process. Passive DPFs, which do not require an external heat source to regenerate, incorporate a catalytic material, typically a platinum group metal, to assist in oxidizing trapped diesel PM.

~~For a complete description of DPFs, refer to Subsection 2.5.2.4.~~

2.5.2.5 Electrostatic Precipitator (ESP)

An ESP is a control device designed to remove particulate matter (both PM_{10} and $PM_{2.5}$) from an exhaust gas stream. ESPs take advantage of the electrical principle that opposites attract. By imparting a high voltage charge to the particles, a high voltage direct current (DC) electrode negatively charges airborne particles in the exhaust stream, while simultaneously ionizing the carrier gas, producing an electrified field. The electric field in an ESP is the result of three contributing factors: the electrostatic component resulting from the application of a voltage in a dual electrode system, the component resulting from the space charge from the ions and free electrons, and the component resulting from the charged particulate. As the exhaust gas passes through this electrified field, the particles are charged. The strength or magnitude of the electric field is an indication of the effectiveness of an ESP. Typically, 20,000 to 70,000 volts are used. The particles, either negatively or positively charged, are attracted to the ESP collecting electrode of the opposite charge. When enough particulates have accumulated, the collectors are shaken to dislodge the dust, causing it to fall by gravity to hoppers below and then removed by a conveyor system for disposal or recycling. ESPs can handle large volumes of exhaust gases and because no filters are used, ESPs can handle hot gases from 350 °F to 1,300 °F.

2.5.2.6 Fuel Gas Treatment

According to a study prepared by ETS, Inc., and Nexidea[3], using a flue gas scrubber is not cost-effective for refinery process heaters and boilers. The consultants concluded that for heaters and boilers, post-combustion emission control is often expensive due to the combination of the relatively low concentrations of SO_2 in flue gases and the division of the fuel gas stream among a number of heaters and boilers. Pre-combustion control, e.g., fuel gas treatment, has been found to be more suitable for the majority of situations to obtain SO_2 emission reductions from refinery process heaters and boilers. Therefore, the analysis of potential environmental impacts from the proposed project in Chapter 3 assumes that an affected refinery operator would likely rely on the fuel gas treatment control option to reduce SO_2 emissions from refinery process heaters and boilers instead of using a flue gas scrubber.

Refinery fuel gas, commonly used for operating refinery process heaters and boilers, is treated in various acid gas processing units such as an amine (Merox[4], for example) treating unit for removal of sour components including hydrogen sulfide (H_2S), carbonyl sulfide (COS), mercaptan, and ammonia. Lean amine is generally used as an absorbent. At the end of the process, the lean amine is regenerated to form rich amine and H_2S is recovered in acid gas, which is then fed to the SRU/TGU for more processing. By improving the efficiency of the amine treating unit to recover more sulfur from the inlet acid gas stream, the sulfur content in the refinery fuel gas at the outlet and subsequently the SO_2 emissions from boilers and heaters that use these refinery fuel gases can be reduced. EmeraChem Power LLC markets a proprietary catalytic gas treatment called selective oxidation catalyst "ESx" that is typically used as a sulfur reducing agent in conjunction with its "EMx NOx trap" catalyst to treat combustion exhaust gases from incinerators, process heaters, turbines, and boilers. The ESx catalyst can also be used as part of SO_2 reduction for sulfur recovery units/tail gas treatment units. The ESx catalyst can reduce multiple sulfur species, including SO_2, SO_3, and H_2S from the tail gas stream while also removing CO, VOC, and $PM_{2.5}$ emissions. ESx catalyst is a platinum group metal catalyst that stores sulfur species and simultaneously assists in the catalytic oxidation of CO and VOCs. The ESx units are typically outfitted with multiple chambers such that at least one chamber is always in regeneration while the other units are working to store SO_2. In the storage process, SO_2 is oxidized to SO_3 and is stored by EmeraChem's sorber. The catalyst regeneration process releases sulfur as SO_2 (Galati, 2008).

2.5.2.7 LoTOx^{TM} Application with Wet Scrubber

The LoTOx^{TM} is a registered trademark of Linde LLC (previously BOC Gases) and was later licensed to BELCO of Dupont for refinery applications. LoTOx^{TM} stands for "Low Temperature Oxidation" process in which ozone (O_3) is used to oxidize insoluble NOx

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[3] SCAQMD. 2010. Final Staff Report SOx RECLAIM – Part 2 – Summary of Consultant's Analysis. November. http://www.aqmd.gov/home/governing-board/agendas-minutes.

[4] Merox is an acronym for mercapatan oxidation and the treatment process is a proprietary catalytic chemical process used for removing mercaptans from refinery fuel gas by converting them to liquid hydrocarbon disulfides. Merox treatment is an alkaline process that typically uses an aqueous solution of sodium hydroxide (NaOH) or caustic.

compounds into soluble NOx compounds which can then be removed by absorption in a caustic, lime, or limestone solution. The LoTOx^{TM} process is a low temperature application, optimally operating at about 325 °F.

A typical combustion process produces about 95 percent NO and five percent NO_2. Because both NO and NO_2 are relatively insoluble in an aqueous solution, a WGS alone is not efficient in removing these insoluble compounds from the flue gas stream. However, with a LoTOx^{TM} system and the introduction of O_3, NO and NO_2 can be easily oxidized into a highly soluble compound N_2O_5 and subsequently converted to nitric acid (HNO_3). Then, in a wet gas scrubber for example, the HNO_3 is rapidly absorbed in caustic (NaOH), limestone or lime solution. The LoTOx^{TM} process can be integrated with any type of wet scrubbers (e.g., venturi, packed beds), semi-dry scrubbers, or wet electrostatic precipitators (ESPs). In addition, because the rates of oxidizing reactions for NOx are fast compared to the very slow SO_2 oxidation reaction, no ammonium bisulfate ($(NH_4)HSO_4$) or sulfur trioxide (SO_3) is formed (Confuorto and Sexton, 2007).

2.5.2.8 Refinery Wet Gas Scrubber (WGS)

Wet gas scrubbers are used to control both SO_2, $PM_{2.5}$, and PM_{10} emissions. When used in conjunction with LoTOx^{TM} control equipment, they can also be used to reduce NOx emissions. There are two types of wet gas scrubbers: 1) caustic-based non-regenerative WGS; and, 2) regenerative WGS.

In a non-regenerative WGS, caustic soda (sodium hydroxide - NaOH) or other alkaline reagents, such as soda ash, are used as an alkaline absorbing reagent (absorbent) to capture SO_2 emissions. The absorbent captures SO_2 and sulfuric acid mist (H_2SO_4) and converts them to various types of sulfites and sulfates (e.g., $NaHSO_3$, Na_2SO_3, and Na_2SO_4). The absorbed sulfites and sulfates are later separated by a purge treatment system and the treated water, free of suspended solids, is either discharged or recycled.

A regenerative WGS removes SO_2 from the flue gas by using a buffer solution that can be regenerated. The buffer is then sent to a regenerative plant where the SO_2 is extracted as concentrated SO_2. The concentrated SO_2 is then sent to a sulfur recovery unit to recover the liquid SO_2, sulfuric acid, and elemental sulfur as a by-product. When the inlet SO_2 concentrations are high, a substantial amount of sulfur-based by-products can be recovered and later sold as a commodity for use in the fertilizer, chemical, pulp and paper industries. For this reason, the use of a regenerative WGS is favored over a non-regenerative WGS. WGS are generally large users of water; however, regenerative WGS use about 25 percent of the water than a non-regenerative WGS.

2.5.2.9 SOx Reducing Additives

To help reduce condensable particulate matter from sulfur, SOx reducing additives (catalysts) are used for reducing the production of SOx by-products in FCCUs. A SOx reducing catalyst is a metal oxide compound such as aluminum oxide (Al_2O_3), magnesium oxide (MgO), vanadium pentoxide (V_2O_5) or a combination of the three that is added to the FCCU catalyst as it circulates throughout the reactor. In the regenerator of the FCCU, sulfur bearing coke is burned and SO_2, CO, and CO_2 by-products are formed. A portion of SO_2 will react with excess oxygen and form SO_3, which will either stay in the flue gas or react with the metal oxide in the SOx reducing catalyst to form metal sulfate. In the FCCU reactor, the metal sulfate will react with hydrogen to form either metal sulfide and water, or more metal oxide. In the steam stripper section of the FCCU reactor, metal sulfide reacts with steam to form metal oxide and H_2S. The net effect of these reactions is that the quantity of SO_2 in the regenerator is typically reduced between 40 to 65 percent while the quantity of H_2S in the reactor is increased. Generally, the increase in H_2S is handled by sulfur recovery processes located elsewhere within a refinery.

2.5.2.10 UltraCat

UltraCat is a commercially available multi-pollutant control technology designed to remove NOx and other pollutants such as SO_2, PM, hydrochloric acid, dioxins, and TACs such as mercury in low temperature applications. UltraCat technology is comprised of filter tubes which are made of fibrous ceramic materials embedded with proprietary catalysts. The optimal operating temperature range of an UltraCat system is approximately 350 °F to 750 °F. To achieve a NOx removal efficiency of approximately 95 percent, aqueous ammonia is injected upstream of the UltraCat filters. In addition, to remove SO_2, HCl, and other acid gases with a removal efficiency ranging from 90 percent to 98 percent, dry sorbent such as hydrated lime, sodium bicarbonate or trona is also injected upstream of the UltraCat filters. UltraCat is also capable of controlling particulates to a level of 0.001 grains per standard cubic foot of dry gas (dscf).

The UltraCat filters are arranged in a baghouse configuration with a low pressure drop such as five inches water column (in water) across the system. The UltraCat system is equipped with a reverse pulse-jet cleaning action that back flushes the filters with air and inert gas to dislodge the PM deposited on the outside of the filter tubes. Depending on the loading, catalytic filter tubes need to be replaced every five to 10 years (Tri-Mer Corp., 2013).

~~For a complete description of UltraCat control systems, refer to Subsection 2.5.2.6.~~

2.5.3 GHG Emissions Reduction Opportunities

The most common GHG pollutants at the affected refineries and support facilities are CO_2, CH_4, and N_2O. These GHG pollutants are typically generated from combustion processes. However, as noted in the Staff Report for the draft rules, GHG emissions from Bay Area refineries are already regulated under the statewide AB 32 Cap-and-Trade system. All major stationary sources of GHG are included under a statewide cap created by CARB's Cap-and-Trade rule. The total GHG emissions from all these sources combined is required to decline over time to meet statewide GHG reduction goals. Since any local caps in the Bay Area would not reduce the total allowable GHG emissions under the statewide cap, it's unclear how local caps would benefit global climate.

Although affected facilities are already subject to GHG emission reduction requirements, GHG emission reduction opportunities that are available at affected facilities would most likely be in the form energy efficiency improvements rather than installation of add-on control equipment. Major areas for energy-efficiency improvement at refineries are utilities (30 percent), fired heaters (20 percent), process optimization (15 percent), heat exchangers (15 percent), motor and motor applications (10 percent), and other areas (10 percent). Of these areas, optimization of utilities, heat exchangers and fired heaters offer the most low-investment opportunities (IPIECA, 2013).

Some examples of methods to improve energy efficiency include, but are not limited to: improving process monitoring and control systems; using high efficiency motors; using variable speed drives; optimizing compressed air systems; and implementing lighting system efficiency improvements (U.S. EPA, 2010). Process integration refers to the exploitation of potential synergies that are inherent in any system that consists of multiple components working together. In plants that have multiple heating and cooling demands, the use of process integration techniques may significantly improve efficiencies. For example, flue gases throughout the refinery may have sufficient heat content to make it economical to recover the heat. Process integration techniques could be accomplished using an economizer to preheat the boiler feed water.

Another example of measures for improving efficiency for boilers include, but are not limited to, maintaining boilers according to a regular maintenance program. In particular, the burners and condensate return system should be properly adjusted and worn components replaced. Average energy savings of about 10 percent can be realized over a system without regular maintenance. Further, insulation of older boilers may be in poor condition, and the material itself may not insulate as well as newer materials. Replacing the insulation combined with improved controls can reduce energy requirements by six to 26 percent. Insulation on steam distribution systems should also be evaluated. Improving the insulation on the distribution pipes at existing facilities may reduce energy usage by three to 13 percent (U.S. EPA, 2010).

The energy used for lighting at a petroleum refinery facilities represent a small portion of the overall energy usage. However, there are opportunities for cost-effective energy efficiency improvements. Automated lighting controls that shut off lights when not needed may have payback periods of less than two years. Replacing T-12 lights with T-8 lights can reduce energy use by half, as can replacing mercury lights with metal halide or high pressure sodium lights (U.S. EPA, 2010).

Another aspect of energy management may include "life cycle" energy performance over the life time of an asset. For example, especially in upstream oil and gas operations, flow volumes can change substantially over time as a field ramps up to peak production, perhaps levels out, and then eventually decline over time. If fluid production and distribution systems are designed for maximum peak capacity, then they will likely only operate for a limited time at design capacity and may spend most of their time at suboptimal operating conditions which will degrade energy efficiency and possibly lead to reliability issues. Designing facilities to adapt to significant load changes over time and maintain high efficiency operation could lead to large energy savings over the life of the asset (IPIECA, 2013).

Carbon capture and storage (CCS) is a technology that takes greenhouse gases emitted from a facility and pumps them into an underground geological formation in order to prevent them from being emitted into the atmosphere where they can contribute to global warming. A number of industrial-scale CCS projects have come online in recent years and maybe promising in the future. However, CCS requires an appropriate reservoir into which GHG emissions can be injected and in many locations there are no such reservoirs within a feasible distance. Therefore, the use of CCS is currently limited.

As indicated in the paragraphs above, energy efficiency measures to reduce GHG emissions primarily include modifying systems' operations and maintenance as well as using more efficient equipment. As a result, installation of add-on control equipment, such as that used for SO_2, NOx, $PM_{2.5}$, and PM_{10}, are not anticipated to be used to reduce GHG emissions, thus, reducing the possibility of producing secondary environmental impacts. Finally, as mentioned in the Staff Report for the draft rules, the facilities that would be subject to draft Rule 12-16 are already subject to GHG emissions reduction requirements pursuant to the statewide AB 32 Cap-and-Trade system. Consequently, GHG emission reductions would occur regardless of whether or not draft Rule 12-16 is adopted.

CHAPTER 1

INTRODUCTION AND EXECUTIVE SUMMARY

1.0 INTRODUCTION AND EXECUTIVE SUMMARY

1.1 INTRODUCTION

The Bay Area Air Quality Management District (BAAQMD or Air District) was established in 1955 by the California Legislature to control air pollution in the counties around San Francisco Bay and to attain federal air quality standards by the dates specified in federal law. There have been significant improvements in air quality in the Bay Area over the last several decades. The BAAQMD is also required to meet state standards by the earliest date achievable.

Petroleum refineries are significant sources of pollutants on both the global (greenhouse gases) and regional/local scale (criteria pollutants and toxic air contaminants). Refineries are extremely large and complex facilities comprising many plants (or process units) that function to refine crude oil into various products such as gasoline, diesel fuel, jet fuel, and asphalt. While historically, refinery emissions have tended to decrease overall over time, it is possible that, as refinery operations change in the future, emissions of these pollutants could increase. Some of the factors that can result in increased refinery emissions include higher production rates to meet increased demand or compensate for loss of production in other regions, upset conditions and accidents, and changes in crude oil or product slates. ~~In response to these concerns, the Board of Directors of the Air District has directed staff to bring forward two draft rules for their consideration, one that reflects policy recommended by environmental advocacy organizations, and a second that follows an approach recommended by Air District staff.~~

Communities for a Better Environment and several associated organizations (CBE) have developed a concept and the Board of Directors have directed Air District staff to develop regulatory language reflecting that concept into new Regulation 12, Rule 16: Petroleum Refining Facility-Wide Emissions Limits (Rule 12-16 or “Refining Caps Rule”). This rule would set numeric limits on specific refinery emissions. Rule 12-16 would apply only to the Bay Area’s five petroleum refineries and three facilities associated with the refineries.

This EIR addresses the impacts due to implementation of ~~Regulation 11-18, Toxic Risk Reduction Rule; and~~ Regulation 12, Rule 16, Refining Caps Rule. The development of ~~these rules~~ Rule 12-16 was included as Action Item 4 in the Air District’s Work Plan for Action Items Related to Accidental Releases from Industrial Facilities, which was approved by the Air District’s Board of Directors on October 17, 2012.

~~The staff of the Air District has developed a different approach that directly addresses concerns about health risks to the refinery communities. The staff recommendation is that the Air District adopt new Regulation 11, Rule 18: Reduction of Risk from Air Toxic Emissions at Existing Facilities (Rule 11-18 or “Toxic Risk Reduction Rule”). Rule 11-18 would apply to all facilities whose emissions of toxic air contaminants may result in a significant risk to nearby residents and workers – this would include petroleum refineries. The purpose of Rule 11-18 is to focus on those facilities causing the highest health impacts across the Bay Area and to require these facilities to reduce that health risk. The draft rule would potentially affect hundreds of facilities, including data centers, petroleum refineries, a cement kiln, gasoline dispensing facilities, etc.~~

~~These facilities emit a variety of TACs that can adversely impact public health. These pollutants include compounds such as diesel particulate matter (DPM), benzene, polycyclic aromatic hydrocarbons (PAHs), and 1,3-butadiene. These toxic emissions are disproportionately impacting vulnerable communities in the Bay Area. Therefore, any risk reduction from existing facilities achieved by this rule is expected to provide greater benefit to these communities.~~

1.2 CALIFORNIA ENVIRONMENTAL QUALITY ACT

The California Environmental Quality Act (CEQA), Public Resources Code Section 21000 et seq., requires that the potential environmental impacts of proposed projects be evaluated and that feasible methods to reduce or avoid identified significant adverse environmental impacts of these projects be identified. To fulfill the purpose and intent of CEQA, the Air District has prepared this Environmental Impact Report (EIR) under the requirements of CEQA Guidelines §15187 to address the potential environmental impacts associated with the proposed Regulation ~~11-18 and~~ 12-16. Prior to making a decision on the adoption of the proposed ~~Toxic Risk Reduction Rule and the~~ Refinery Caps Rule, the Air District Governing Board must review and certify the EIR as providing adequate information on the potential adverse environmental impacts of implementing the proposed new ~~Rules~~ Rule.

1.2.1 NOTICE OF PREPARATION/INITIAL STUDY

A Notice of Preparation for the Draft EIR for Regulation 11-18, the Toxics Risk Reduction Rule, and 12-16, the Refinery Caps Rule (included as Appendix A of this EIR) was distributed to responsible agencies and interested parties for a 30-day review on October 16, 2016. A notice of the availability of this document was distributed to other agencies and organizations and was placed on the Air District's web site, and was also published in newspapers throughout the area of the Air District's jurisdiction. Seven public comment letters were submitted on the NOP to the Air District and are included in Appendix A of this EIR.

The NOP/IS identified the following environmental resources as being potentially significant, requiring further analysis in the EIR: air quality, greenhouse gases, hazards and hazardous materials, hydrology and water quality, and utilities and service systems. Please note that the hydrology and water quality impacts were determined to be potentially significant due to the potential increase in water demand. The utilities and service systems impacts were also determined to be potentially significant due to increased water demand. To avoid repetition, the potential water demand impacts have been consolidated and evaluated under hydrology and water impacts (only). The following environmental resources were considered to be less than significant in the NOP/IS: aesthetics, agriculture and forestry resources, biological resources, cultural resources, geology/soils, land use/planning, mineral resources, noise, population/ housing, public services, recreation, transportation/ traffic, and utilities/service systems (see Appendix A).

1.2.2 TYPE OF EIR

In accordance with §15121(a) of the State CEQA Guidelines (California Administrative Code, Title 14, Division 6, Chapter 3), the purpose of an EIR is to serve as an informational document that: "will inform public agency decision-makers and the public generally of the significant environmental effect of a project, identify possible ways to minimize the significant effects, and describe reasonable alternatives to the project." The EIR is an informational document for use by decision-makers, public agencies and the general public. The proposed project requires discretionary approval and, therefore, it is subject to the requirements of CEQA (Public Resources Code, §21000 et seq.).

The focus of this EIR is to address the environmental impacts of the implementation of ~~Regulations 11-18 and~~ Regulation 12-16 as identified in the NOP and Initial Study (included as Appendix A of this EIR). Since the release of the Draft EIR, the District has removed Regulation 11-18 from this EIR. This Final EIR reflects this change. The degree of specificity required in an EIR corresponds to the degree of specificity involved in the underlying activity described in the EIR (CEQA Guidelines §15146). Regulation 12-16 would establish maximum refinery-wide emissions limits for nitrogen oxides (NOx), sulfur dioxide (SO_2), particulate matter and GHGs at five refineries and three associated facilities in the Air District. If limits and thresholds are exceeded, additional emission reductions would be required. ~~Regulation 11-18 would apply to a much larger variety of sources and focus on those facilities causing the highest health impacts across the Bay Area and to require these facilities to reduce that health risk.~~ Since the need for emission reductions has not yet been determined, the actual control measures that will be required to reduce emissions, if any, is unknown. Therefore, the EIR evaluates the impacts of potential emissions control measures that could be utilized.

1.2.3 INTENDED USES OF THIS DOCUMENT

In general, a CEQA document is an informational document that informs a public agency's decision-makers, and the public generally, of potentially significant adverse environmental effects of a project, identifies possible ways to avoid or minimize the significant effects, and describes reasonable alternatives to the project (CEQA Guidelines §15121). A public agency's decision-makers must consider the information in a CEQA document prior to making a decision on the project. Accordingly, this EIR is intended to: (a) provide the Air District's Board of Directors and the public with information on the environmental effects of the proposed project; and, (b) be used as a tool by the Air District's Board to facilitate decision making on the proposed project.

Additionally, CEQA Guidelines §15124(d)(1) requires a public agency to identify the following specific types of intended uses of a CEQA document:

1. A list of the agencies that are expected to use the EIR in their decision-making;

2. A list of permits and other approvals required to implement the project; and

3. A list of related environmental review and consultation requirements required by federal, state, or local laws, regulations, or policies.

Local public agencies, such as cities, and counties could be expected to tier off this EIR if local approval is required for the installation of air pollution control equipment that may be required when implementing Rule ~~11-18 or~~ 12-16, pursuant to CEQA Guidelines §15152. There is no State, federal or local permits required to adopt ~~either of~~ the proposed ~~rules~~ Rule. However, implementation of the ~~rules~~ Rule could require permits from local governments (e.g., cities and counties with land use approval).

1.2.4 AREAS OF POTENTIAL CONTROVERSY

In accordance with CEQA Guidelines §15123(b)(2), the areas of controversy known to the lead agency including issues raised by agencies and the public shall be identified in the EIR. As noted above, six comment letters were received on the NOP/IS. Seven comment letters were received on the Draft EIR. Issues and concerns raised in the comment letters included: (1) concerns that the District has piecemealed the CEQA refinery projects; (2) concerns that refinery expansion projects and trends toward increased exports have not been included; (3) concerns about potential legal conflicts and consistency with the Clean Air Act, as well as CARB's Cap and Trade Program; (4) an adequate environmental setting should be included; (5) an alternative to use the 25/M risk threshold option and other concerns regarding the alternatives analysis; and (6) cross-media environmental impacts should be evaluated. Copies of the comment letters on the NOP/IS are provided in Appendix A. The comment letters and responses to the comments received on the Draft EIR are included in Appendix C.

1.3 EXECUTIVE SUMMARY: CHAPTER 2 – PROJECT DESCRIPTION

Petroleum refineries are sources of harmful pollutants on a global (climate pollutants i.e., greenhouse gases), regional (criteria pollutants), and local scale (toxic air contaminants and particulate matter). Many Bay Area residents have expressed concern about the impact of this pollution on the environment and public health, particularly those that may disproportionately impact communities near refineries. Though refinery emissions have declined over time, it is possible that as refinery operations change in the future, emissions of these pollutants could increase. ~~In response to these concerns, the Board of Directors of the Air District has directed staff to bring forward two rules for their consideration: one that reflects policy recommended by some environmental advocacy organizations; and an approach recommended by Air District staff.~~

Communities for a Better Environment (CBE) and several associated organizations have recommended that the Air District adopt new Regulation 12, Rule 16: Petroleum Refining Facility-Wide Emissions Limits (Rule 12-16 or "Refining Caps Rule"). This rule would set numeric limits on specific refinery emissions. Rule 12-16 would apply only to the Bay Area's five petroleum refineries and three facilities associated with the refineries.

~~The staff of the Air District has developed a different approach that directly addresses concerns about health risks to communities exposed to air pollution. The staff recommendation is that the Air District adopt a new Regulation 11, Rule 18: Reduction of Risk from Air Toxic Emissions at Existing Facilities (Rule 11-18 or "Toxic Risk Reduction Rule"). Rule 11-18 would apply to all facilities in the Bay Area whose emissions of toxic air contaminants may result in a significant risk to nearby residents and workers, including petroleum refineries. The purpose of Rule 11-18 is to reduce the public's exposure to health risks associated with the emissions of toxic air contaminants (TACs) from stationary sources by reducing those risks to the lowest feasible levels.~~

1.3.1 Rule 12-16 – Refinery Emissions Caps Rule

Rule 12-16 reflects a policy recommendation from CBE and their associated organizations. The proposed rule, as proposed by CBE, would limit the emissions of climate pollutants and three criteria pollutants: greenhouse gases (GHGs), particulate matter (PM), oxides of nitrogen (NOx), and sulfur dioxide (SO_2) from petroleum refineries and three associated facilities. The rule would establish facility-wide emissions limits for the covered pollutants at each of the affected facilities to ensure that each facility does not increase emissions due to changes in operation, crude or product slates; or increases in production. Each facility's emissions limits would be set at the maximum-annual emissions reported for that facility in the period from 2011 through 2015 with an additional allowance or "threshold factor" of seven percent over the maximum annual emission rate for each pollutant.

~~1.3.2 Rule 11-18 – Toxic Risk Reduction Rule~~

~~Rule 11-18, as drafted by Air District staff, would ensure that emissions of TACs from existing facilities do not pose an unacceptable health risk to people living and working nearby. The rule would use the most up-to-date assumptions about the risk of compounds and would require the facility to take action to reduce risk below a specified risk threshold if the facility exceeds the risk thresholds. If the facility could not devise a means to reduce the risk below the specified risk level, the facility would be required to install best available retrofit control technology for toxic pollutants (TBARCT) on every significant source of TAC emissions at the facility.~~

1.3.3 PROJECT OBJECTIVES

~~The objectives of Toxic Risk Reduction Rule (Reg. 11-18) are to:~~

- ~~Reduce the public's exposure to health risks associated with the emissions of TACs from stationary sources to the lowest levels achievable;~~
- ~~Incorporate the most up-to-date health risk methodologies and health values into the Air District's risk evaluation process for existing stationary sources of TACs;~~
- ~~Ensure the facilities that impact the most sensitive and overburdened communities reduce their associated health risk in an efficient and expeditious manner;~~

- ~~Provide the public opportunity to comment on the draft HRAs to provide transparency and clarity to the process; and~~

- ~~Provide the public opportunity to comment on risk reduction plans as they are drafted by the affected facilities.~~

The objectives of the Refining Emission Caps Rule (Reg. 12-16) are to:

- Protect air quality, public health, and the climate from increases in annual facility-wide mass emissions of GHGs, PM, NOx, and SO_2 caused by changes in refinery oil feed quality or quantity, refinery or support equipment or operation, or combinations of these causes, by preventing any significant increase in these emissions;

- Protect the climate and public health by preventing any significant increase in these emissions at refineries and associated facilities from increasing the emission intensity of the production of transportation fuels;

- Protect community and public health by preventing any significant increase in these emissions from worsening hazards for which HRA methods may not account, including but not limited to acute and chronic ambient NOx, SOx, and PM exposure hazards;

- Complement other air quality, public health, and climate measures by discouraging investment in new refinery equipment that would lead to increased emissions of GHG, PM, NOx, or SOx from Bay Area refineries.

1.3.3.1 Sources Affected by ~~Regulations 11-18 and~~ Regulation 12-16 and Applicable Control Technologies

Regulation 12-16 would apply to the five refineries and three support facilities in the Bay Area. ~~Rule 11-18 would apply to sources that generate TAC emissions and include a variety of emission sources, as identified below.~~

- ~~Refineries~~
- ~~Data Centers~~
- ~~Cement Manufacturing~~
- ~~Chemical Plants~~
- ~~Crematoria~~
- ~~Landfills~~
- ~~Foundries~~
- ~~Sewage Treatment Facilities~~
- ~~Power Plants~~
- ~~Gasoline Stations~~
- ~~Military Facilities~~

- ~~Manufacturing Facilities~~

1.4 EXECUTIVE SUMMARY: CHAPTER 3 – ENVIRONMENTAL SETTING, IMPACTS AND MITIGATION MEASURES

This chapter of the Draft EIR describes the existing environmental setting in the Bay Area, analyzes the potential environmental impacts of ~~Rules 11-18 and~~ Rule 12-16 and recommends mitigation measures (when significant environmental impacts have been identified). The chapter provides this analysis for each of the environmental areas identified in the Initial Study (see Appendix A), including: (1) Air quality; (2) Climate change and greenhouse gas emissions; (3) Hazards and Hazardous Materials; and (4) Hydrology and Water quality. Included for each impact category is a discussion of the environmental setting, significance criteria, whether the proposed rule ~~2017 Plan~~ will result in any significant impacts (either ~~from the Plan~~ individually or cumulatively in conjunction with other projects), and feasible project-specific mitigation (if necessary and available). The Initial Study concluded that potential water demand impact on hydrology/water quality and utilities/service systems were potentially significant. Note that the potential water demand impacts have been consolidated into one discussion under hydrology and water quality to avoid repetition.

1.4.1 AIR QUALITY

1.4.1.1 Air Quality Setting

It is the responsibility of the Air District to ensure that State and federal ambient air quality standards are achieved and maintained in its geographical jurisdiction. Health-based air quality standards have been established by California and the federal government for the following criteria air pollutants: ozone, CO, nitrogen dioxide (NO_2), particulate matter (PM10 and PM2.5), sulfur dioxide (SO_2), and lead. These standards were established to protect sensitive receptors with a margin of safety from adverse health impacts due to exposure to air pollution. California has also established standards for sulfate, visibility, hydrogen sulfide, and vinyl chloride.

The Air District is in attainment of the State Ambient Air Quality Standards for CO NO_2, and SO_2. However, the Bay Area does not comply with the State 24-hour PM10 standard. The Air district is unclassifiable/attainment for the federal NO, NO_2, SO_2, lead, and PM10 standards. A designation of unclassifiable/attainment means that the U.S. EPA has determined to have sufficient evidence to find the area either is attaining or is likely attaining the National Ambient Air Quality Standards. The Bay Area is designated as a non-attainment area for the federal and state 8-hour ozone standard and the federal 24-hour PM2.5 standard. The State 8-hour standard was exceeded on 12 days in 2015 in the Air District; most frequently in the Eastern District (Livermore, Patterson Pass, and San Ramon). The federal 8-hour standard was exceeded on 12 days in 2015.

The Air District monitors and maintains databases that contains information concerning criteria pollutant and TAC emissions from sources in the Bay Area. The criteria pollutant emission concentrations and inventory data are used to determine compliance with state and federal ambient air quality standards as well as to determine the most appropriate approach to complying with ambient air quality standards. TAC emission inventories are used to plan strategies to reduce public exposure to TACs. The primary health risk of concern due to exposure to TACs is the risk of contracting cancer. The carcinogenic potential of TACs is a particular public health concern because many scientists currently believe that there are not "safe" levels of exposure to carcinogens without some risk to causing cancer. Based on ambient air quality monitoring, and using OEHHA cancer risk factors, the estimated lifetime cancer risk for Bay Area residents, over a 70-year lifespan from all TACs combined, declined from 4,100 cases per million in 1990 to 690 cases per million people in 2014.

1.4.1.2 Air Quality Impacts

~~**Rule 11-18:** Based on the evaluation of those air pollution control technologies that would most likely be the used to reduce TAC emissions from affected facilities if required pursuant to Rule 11-18, construction and secondary operational air quality impacts from the proposed project could generate NOx emissions that exceed the Air District's construction and operations emission thresholds. Therefore, construction and operational air quality impacts are concluded to be significant for NOx emissions. Emissions of ROG, PM10 and PM2.5 were determined to be less than significant during both construction and operational phases associated with implementation of Rule 11-18.~~

Rule 12-16: Based on the evaluation of those air pollution control technologies that would most likely be the used to reduce GHG, PM2.5, PM10, NOx and SO_2 emissions from affected refinery and refinery-related facilities if required pursuant to Rule 12-16, operational air quality impacts from the proposed project would not exceed the Air District's operations emission thresholds for ROG, NOx, PM10 or PM2.5 and are considered to be less than significant. However, construction air quality impacts from the proposed project could generate NOx emissions that exceed the Air District's construction emission thresholds. Therefore, air quality impacts are concluded to be significant for NOx emissions during construction activities. Potential air quality impacts for ROG, PM10 and PM2.5 were determined to be less than significant during construction activities.

~~Based on the evaluation of those air pollution control technologies that would most likely be the used to reduce PM2.5, PM10, NOx, SO_2, and TAC emissions from affected facilities if both Rules 11-18 and 12-16 were adopted, construction and secondary operational air quality impacts from the proposed project could generate NOx emissions that exceed the Air District's construction and operations emission thresholds. Therefore, construction and operational air quality impacts are concluded to be significant for NOx emissions. Potential air quality impacts for ROG, PM10 and PM2.5 were determined to be less than significant during construction and operational activities, if both Rules 11-18 and 12-16 are implemented. Cumulative impacts associated with NOx emissions during both construction and operation are also considered to be cumulatively significant due to the potential exceedance of significance thresholds under a worst-case analysis.~~

Mitigation measures were identified for the potentially significant NOx emissions associated with construction ~~and operational~~ activities; nonetheless, it is likely that these emissions would remain significant following mitigation.

1.4.2 GREENHOUSE GAS EMISSIONS

1.4.2.1 Greenhouse Gas Emissions Setting

Global climate change refers to changes in average climatic conditions on the earth as a whole, including temperature, wind patterns, precipitation and storms. Global warming, a related concept, is the observed increase in the average temperature of the earth's surface and atmosphere. One identified cause of global warming is an increase of GHGs in the atmosphere. The six major GHGs identified by the Kyoto Protocol are CO_2, methane (CH_4), nitrous oxide (N_2O), sulfur hexafluoride (SF_6), haloalkanes (HFCs), and perfluorocarbons (PFCs), plus black carbon.

It is the increased accumulation of GHGs in the atmosphere that may result in global climate change. Climate change involves complex interactions and changing likelihoods of diverse impacts. Due to the complexity of conditions and interactions affecting global climate change, it is not possible to predict the specific impact, if any, attributable to GHG emissions associated with a single project, which is why GHG emission impacts are considered to be a cumulative impact.

Transportation sources generate approximately 40 percent of the total GHG emissions in the District. The remaining 60 percent of the total District GHG emissions are from stationary and area sources.

1.4.2.2 Greenhouse Gas Emissions Impacts

Most GHG emissions sources at ~~facilities~~ refineries that would be regulated by ~~either Rule 11-18 or~~ Rule 12-16 would include equipment or processes, primarily combustion sources that are part of the facilities' operations. Though the proposed project may include combustion processes that could generate GHG emissions such as CO_2, CH_4, and N_2O, the proposed project does not affect equipment or operations that have the potential to emit other GHGs such as sulfur hexafluoride (SF6), hydrofluorocarbon (HFC) or perfluorocarbon (PFC). GHGs could be emitted during construction activities to install air pollution control equipment from sources such as off-road construction equipment, which could be comprised of off-road mobile sources, e.g., bull dozers, cranes, forklifts, etc. GHGs could also be emitted during construction from on-road mobile sources such as haul trucks delivering products used in the pollution control process and construction worker commute trips. ~~During operation, GHG emission impacts could occur from air pollution control equipment that uses combustion as part of the control process such as thermal oxidizers and the regeneration process for carbon adsorption.~~ GHG emissions would also be generated by increased use of electricity and increased mobile source emissions associated with material deliveries (e.g., sodium hydroxide used in wet gas scrubbers or ammonia used in SCRs)

~~**Rule 11-18:** Greenhouse gas impacts associated with the implementation of air pollution control equipment for the reduction of TAC emissions under Rule 11-18 were found to potentially exceed the Air District's GHG significance threshold of 10,000 MTCO2e/yr and are therefore found to be significant.~~

Rule 12-16: Greenhouse gas impacts associated with the implementation of air pollution control equipment for the potential reduction of refinery emissions under Rule 12-16 were found to be less than the Air District's operational GHG significance threshold of 10,000 MTCO2e/yr and are therefore found to be less than significant.

~~If both rules are adopted, cumulative GHG emission impacts would be greater than either rule alone. GHG emissions would exceed the significance threshold and, therefore, would be significant. It should be noted that GHG emission increases due to implementation of Rule 11-18 and 12-16 from facilities that are regulated under CARB's Cap and Trade Program would be offset. There is no specific information as to what facilities would be located; therefore, it is speculative to assume that all GHG emissions would be offset under the AB 32 Cap and Trade Program. To present a conservative analysis no AB32 Cap and Trade allowances were included in the impact analysis.~~

A review of the GHG emissions reported by refineries and associated facilities indicates that the proposed refinery limitations in Rule 12-16 would not be expected to conflict with CARB's Cap and Trade program because covered entities could continue to use GHG credits for compliance purposes. That data may not be predictive of future scenarios; however, it is the only data available at this time. Presuming continuing increases in gasoline consumption results in unreasonable levels of speculation. For example, it is impossible for the Air District to predict the exact level of gasoline consumption in 2018 and how that would relate to Bay Area refinery capacity and how the market might react if production at Bay Area refineries were constrained by Rule 12-16. Therefore, the Air District is assuming, based on historical data that potential GHG emission impacts from the proposed project are concluded to be less than significant.

1.4.3 HAZARDS AND HAZARDOUS MATERIALS

1.4.3.1 Hazards and Hazardous Materials Setting

The potential for hazards exist in the production, use, storage and transportation of hazardous materials. Hazardous materials may be found at industrial production and processing facilities. Some facilities produce hazardous materials as their end product, while others use such materials as an input to their production process. Examples of hazardous materials used as consumer products include gasoline, solvents, and coatings/paints. Hazardous materials are stored at facilities that produce such materials and at facilities where hazardous materials are a part of the production process. Currently, hazardous materials are transported throughout the district in great quantities via all modes of transportation including rail, highway, water, air, and pipeline.

The potential hazards associated with industrial activities are a function of the materials being processed, processing systems, and procedures used to operate and maintain the facility. The hazards that are likely to exist are identified by the physical and chemical properties of the materials being handled and their process conditions and include: (1) toxic gas clouds due to releases of volatile chemicals; (2) fires or explosions; (3) thermal radiation from the heat generated by a fire; and (4) explosion and overpressure when vessels containing flammable explosive vapors and potential ignition sources are combined.

In 2015, there were a total of 1,272 hazardous materials incidents reported in the nine counties regulated by the Air District, with the most incidents (292) reported in Alameda County. H**azardous materials incidents during transportation, at waterways, and at commercial facilities were the most common locations, respectively, for hazardous materials incidents. About 17 percent of the hazardous materials incidents that occurred within California occurred within the nine counties that comprise the Bay Area, with spills in industrial areas the most common (27 percent), followed by waterways (22 percent) and commercial areas (20 percent).**

1.4.3.2 Hazards and Hazardous Materials Impacts

~~**Rule 11-18:** Proposed Rule 11-18 is designed to reduce health risk associated with emissions of TACs from existing stationary sources in the Bay Area. The proposed rule is not expected to require substantial new development. Any new air pollution control equipment or enclosures would be expected to occur within existing commercial or industrial facilities. Facility modifications associated with the proposed rule are largely expected to include limiting throughput or hours of operations; increased use of diesel particulate filters; additional enclosures and bag houses, and thermal oxidizers or carbon adsorption systems. The hazards associated with the use of these types of air pollution control equipment and systems are minimal.~~

Rule 12-16: For any refineries that are shown to exceed the refinery-wide emissions limits for NOx, SO_2, particulate matter or GHGs, it is expected that refinery operators would install new or modify their existing air pollution control equipment in order to reduce the applicable emissions to comply with Rule 12-16 requirements. Because refineries handle a number of hazardous materials, potential hazards and hazardous materials impacts already exist; are generally common to most oil processing facilities worldwide; and are a function of the materials being processed, processing systems, procedures used for operating and maintaining the facility, and hazard detection, and mitigation systems. The major types of public safety risks at a refinery consist of risks from accidental releases of regulated substances and from major fires and explosions. Additionally, air pollution control equipment that may be installed to obtain further reductions in NOx, SO_2, particulate matter or GHGs emissions have the potential to generate hazard or hazardous materials impacts.

~~Assuming the adoption of both rules, it would be expected that more air pollution control equipment would be required to be installed as additional TAC emissions would be controlled, as well as additional refineries emissions may also be required to be controlled.~~ As discussed in Chapter 3.4.4, installation of most air pollution control equipment would not generate additional hazard impacts. Only baghouses and wet electrostatic precipitators were found to be potentially significant without mitigation; however, the potentially adverse hazard impacts associated with the installation of baghouses and ESPs are expected to be less than significant after mitigation ~~for both Rules 11-18 and 12-16, individually or combined~~. Additionally, because hazards and hazardous materials impacts do not exceed the applicable hazards and hazardous materials significance thresholds, they are not considered to be cumulatively considerable (CEQA Guidelines §15064 (h)(1)) and, therefore are not expected to generate significant adverse cumulative hazards and hazardous materials impacts.

1.4.4 HYDROLOGY AND WATER QUALITY

1.4.4.1 Hydrology and Water Quality Setting

The District is within the San Francisco Bay Hydrologic Region (Bay Region) which includes all of San Francisco County and portions of Marin, Sonoma, Napa, Solano, San Mateo, Santa Clara, Contra Costa, and Alameda counties. It occupies approximately 4,500 square miles; from southern Santa Clara County to Tomales Bay in Marine County; and inland to near the confluence of the Sacramento and San Joaquin rivers at the eastern end of Suisun Bay. The eastern boundary follows the crest of the Coast Ranges, where the highest peaks are more than 4,000 feet above mean sea level.

The most prominent surface water body in the Bay Region is San Francisco Bay itself. Other surface water bodies include: Creeks and rivers; ocean bays and lagoons (such as Bolinas Bay and Lagoon, Half Moon Bay, and Tomales Bay); urban lakes (such as Lake Merced and Lake Merritt); human-made lakes and reservoirs (such as Lafayette Reservoir, Briones Reservoir, Calaveras Reservoir, Crystal Springs Reservoir, Kent Lake, Lake Chabot, Lake Hennessey, Nicasio Reservoir, San Andreas Lake, San Antonio Reservoir, San Pablo Reservoir, Upper San Leandro Reservoir, Anderson Reservoir, and Lake Del Valle).

The Bay Area relies on imported water, local surface water, and groundwater for water supply. Local supplies account for about 30 percent of the total, and the remaining supply is imported from the State Water Project (SWP), Central Valley Project (CVP), and the Mokelumne and Tuolumne watersheds. In 2010, water demand in the region was 1,278,480 acre-feet per year (af/yr)[1]. Demand is projected to grow to 1,680,963 af/yr in a normal year, and 1,666,870 af/yr in a single dry year by 2035.

Some water agencies in the region have imported water from the Sierra Nevada for nearly a century to supply customers. The East Bay Municipal Utility District (EBMUD) and San Francisco Public Utilities Commission (SFPUC) import surface water into the Bay Region from the Mokelumne and Tuolumne rivers via the Mokelumne and Hetch Hetchy aqueducts, respectively. Water from these two rivers accounts for approximately 38 percent of the average annual water supply in the Bay Area. Water from the Sacramento-San Joaquin Delta (Delta), via the federal CVP and the SWP, accounts for another 28 percent. Approximately 31 percent of the average annual water supply in the Bay Area comes from local groundwater and surface water; and three percent is from miscellaneous sources such as harvested rainwater, recycled water, and transferred water.

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[1] One acre-foot of water is equal to approximately 325,851 gallons.

~~As discussed in the Initial Study, implementation of Rule 11-18 would reduce risk from facilities that emit toxic air contaminants throughout the Bay Area. Risk reduction measures are expected to be limited to new air pollution control equipment and construction of enclosures. The NOP/IS concluded that wet gas scrubbers were not expected to be used to control TACs; therefore, implementation of Rule 11-18 was not expected to result in a substantial increase in water use or wastewater discharge. However, public comments received on the NOP/IS indicated that wet gas scrubbers could be used to control TAC emissions from some refinery sources, such as FCCUs.~~

1.4.4.2 Hydrology and Water Quality Impacts

Implementation of Rule 12-16 would prevent refinery emissions of GHGs and some criteria pollutants from increasing. However, Rule 12-16 could require the installation of additional air pollution control equipment or modifications to refinery operations. Control measures for particulate matter and/or SOx emissions could require additional water use and wastewater discharge from devices like wet gas scrubbers. The NOP/IS (see Appendix A) determined that potential hydrology and water quality impacts associated with implementation of the proposed new Rule 12-16 are potentially significant, and the water demand impacts has been evaluated in Chapter 3.5 of this EIR. ~~In addition, wet gas scrubbers could be used to comply with Rule 11-18 so the potential water demand impacts of wet gas scrubbers under Rule 11-18 have also been evaluated in chapter 3.5 of this EIR.~~

~~**Rule 11-18:** If any stationary sources are shown to exceed threshold limits for toxic air contaminants, it is expected that facility operators could install new, or modify their existing air pollution control equipment in order to reduce TAC emissions under Regulation 11-18. Most air pollution control equipment does not use water or generate wastewater. However, additional water demand and wastewater generation impacts are expected to result from the operation of wet gas scrubbers which may be used for control of particulate TAC emissions.~~

Rule 12-16: If any refineries are shown to exceed the refinery-wide emissions limits for PM2.5, PM10, NOx or SO_2, it is expected that refinery operators would install new, or modify their existing air pollution control equipment in order to reduce emissions as required by Regulation 12-16. Additional water demand and wastewater generation impacts are expected to result from the operation of several of the possible control technologies that would most likely be used including wet ESPs and wet gas scrubbers.

Wet gas scrubbers installed as a response to Rule 12-16 ~~and/or Rule 11-18~~ were found to be significant for potential future water demand impacts. Thus, mitigation measures are imposed for the operational use of wet gas scrubbers. However, because of the prevalence of drought conditions in California, in spite of implementing the mitigation measures described in Chapter 3.5.5, water demand impacts during operation of the proposed project remain significant, in part because there is currently no guarantee that reclaimed water will be available to all of the affected facilities. Therefore, the proposed project will remain significant after mitigation for water demand. In addition, water demand impacts during operation of the proposed project are also considered to be cumulatively considerable (CEQA Guidelines §15064 (h)(1)).

Water quality impacts associated with installing various types of air pollution control equipment would not exceed applicable water quality significance thresholds and therefore were found to be less than significant. Additionally, future demand impacts of wet ESPs for compliance with Rule 12-16 were found to be less than significant.

1.4.5 UTILITIES AND SERVICE SYSTEMS

The NOP/IS found that utilities and service system impacts relating to water demand and wastewater treatment could be potentially significant. These potential impacts have been thoroughly discussed in Chapter 1.4.4 and Chapter 3.5 (hydrology and water quality) of the EIR. Water demand impacts were found to be potentially significant following mitigation and water quality impacts ~~DEIR and~~ were found to be less than significant.

1.5 EXECUTIVE SUMMARY: CHAPTER 4 – ALTERNATIVES

An EIR is required to describe a reasonable range of feasible alternatives to the proposed project that could feasibly attain most of the basic project objectives and would avoid or substantially lessen any of the significant environmental impacts of the proposed project (CEQA Guidelines §15126.6(a)). As discussed in Chapter 3 of this EIR the proposed project could result in potentially significant impacts to air quality and GHG emissions during construction and hydrology (water demand) during project operation. An EIR is required to describe a reasonable range of feasible alternatives to the proposed project that could feasibly attain most of the basic project objectives and would avoid or substantially lessen any of the significant environmental impacts of the proposed project (CEQA Guidelines §15126.6(a)).

~~Since there are two proposed rules being evaluated under this EIR, two “No Project Alternatives,” and two Project Alternatives (one each for each of proposed rules) will be consider in this analysis.~~

~~1.5.1 Project Alternatives for Proposed Rule 11-18~~

~~For proposed Rule 11-18, Alternative 1.1 is the No Project Alternative (11-18). Under the No Project Alternative (11-18), the proposed rule would not be adopted and, thus, the Air District would not establish risk actions levels of 10/M for cancer health risk and 1.0 for both acute and chronic hazard indices. Although, portions of the rule could be implemented under the Air District’s AB 2588 – Air Toxics “Hot Spots” Program, such as incorporating the new OEHHA health risk assessment protocols and health risk values and conducting health risk screening analyses and health risk assessments. Facilities with a cancer health risk greater than 10/M or an acute or chronic hazard index greater than 1.0[2] would only have to notify all exposed persons of their exposure. Facilities with a cancer risk greater than 100/M or a hazard indices greater than~~

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[2] ~~Health risks of 10/M cancer and 1.0 hazard indices are current action levels for notification under the Air District’s AB 2588 Air Toxics “Hot Spots” Program.~~

~~10 would have to both 1) notify exposed individuals, and 2) reduce the facility health risk below the risk action level in accordance to the Air District AB 2588 Program, California Health and Safety Code, §§44300-44394.~~[3]

~~Under Alternative 1.2, the Air District would establish risk action levels at 25/M for cancer risk and 2.5 for hazard indices instead of 10/M and 1.0 respectively. Further, the significant risk level for the compliance alternative for the application of best available retrofit control technology for toxics (TBARCT) would be set at 5/M for cancer and 0.5 hazard indices or removed.[4] All other aspects of the proposed rule would remain in place, including the provisions for the two compliance options: developing a risk reduction plan or demonstrating that all significant sources of risk are controlled with TBARCT. Under this alternative, the scope of the project would be significantly reduced because the rule would not apply to those facilities with health risks that are less than 25/M for cancer or 2.5 for hazard indices. As a result, the number of facilities affected by the rule would be reduced by from approximately 1,000 to fewer than 100 – an order of magnitude reduction. the requirements of the rule would still apply to major sources of risk, such as refineries, cement manufacturing, and waste water treatment facilities; however, the level to which those facilities must reduce their health risk would be 25/M instead of 10/M. Under this alternative, the number of individuals that remain exposed to elevated health risk levels posed by these facilities would be much greater than that under the proposal.~~

~~Since Alternative 1.2 would eliminate all of the potentially significant impacts and achieve most of the project objectives, it would be considered the environmentally superior alternative.~~

~~1.5.2 Project Alternatives for Proposed Rule 12-16~~

~~For proposed Rule 12-16, Alternative 2.1 is the No Project Alternative (12-16).~~ Under the No Project Alternative~~ (12-16)~~, the proposed rule would not be adopted and, thus, facility-wide emissions limits on GHGs, PM (PM_{10} and $PM_{2.5}$), NOx, and SO_2 would not be established. Therefore, the control of these emissions would likely continue to be addressed by the Air District current suite of programs, rules, regulations and any future measures contained in the draft 2017 Clean Air Plan and the State statues affecting climate pollutants. These methods of control include:

- Air District Rules affecting emissions of PM, NOx, and SO_2 from refineries and associated facilities.
- Control measures in the 2010 CAP not yet adopted;
- Rules and rule amendments in the Refinery Strategy;
- Control measures in draft 2017 CAP (not too speculative), including Rule 13.1; and
- AB 32 Cap and Trade Program, SB 32 and AB 197

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[3] ~~Health risks of 100/M cancer and 10.0 hazard indices are the current action levels for risk reduction under AB 2588. It should be noted that Air District staff did not identify any facilities with a preliminary health risks greater than these action levels.~~

~~[4] Without the TBARCT compliance option, the rule would be, in effect, an implementation of the AB 2588 program with lower risk action levels.~~

The primary differences between Rule 12-16 and the No Project Alternative (12-16) is that the collection of measures listed referenced above would not only prevent the increase of climate and combustion criteria pollutants, but would result in substantial decreases of these pollutants over time (the proposal does not require emissions reductions).

Alternative 2.2 would be the implementation of the combination of proposed Rule 11-18 and draft Rule 13-1. This alternative would consist of a combination of the environmental benefits and impacts of adopting and implementing proposed Rule 11-18 and draft Rule 13-1. Under this alternative, Rule 11-18 would reduce refinery health risks due to the emissions of toxic air contaminants to the lowest achievable levels, greatly reducing the health risks experienced by communities from refinery toxic emissions. Under proposed Rule 11-18, facilities that posed a health risk greater than the risk action levels of 10/M for cancer and 1.0 for hazard indices would have to either 1) reduce the facility health risk below the actions levels through the implementation of a risk reduction plan, or 2) demonstrate that all significant sources of risk at the facility are controlled with TBARCT.

Further, draft Rule 13-1 would ensure that refinery emission of GHGs are either limited to their current maximum capacity or are constrained by the refineries' carbon intensity based on their maximum capacity (also incorporating cost-saving energy efficiency measures). Draft Rule 13-1 would complement and serve as a backstop for State climate protection efforts, which are anticipated to require a 20 percent reduction in refinery GHG emissions by 2030. Draft Rule 13-1 would:

- Set a carbon intensity limit for each refinery consistent with current operations
- Set a mass-based GHG emissions limit as an alternate compliance option
- Provide incentives for new energy improvement projects
- Accommodate new regulatory requirements and Air District permits

Alternative 2.2 would achieve all the project objectives to a greater extent than the no proposed project alternative, with a reduced level of environmental impacts as compared to the proposed project. A combination of Rule 11-18 and Rule 13-1 would directly reduce health risks from refining operations through the implementation of risk reduction measures and limit GHG emissions from refining operation. Therefore, the Alternative 2.2 is the preferred alternative.

~~Since Alternative 2.2 would eliminate all of the potentially significant impacts and achieve all of the project objectives, it would be considered the environmentally superior alternative, providing an improvement in air quality not provided by the other project alternatives.~~

1.6 EXECUTIVE SUMMARY: CHAPTER 5

Chapter 5 provides the references used in the preparation of the EIR.

TABLE 1-1

Summary of Environmental Impacts, Mitigation Measures and Residual Impacts

Impact	Mitigation Measures	Residual Impacts
Air Quality		
The construction activities that may be required to implement ~~Rule 11-18 and~~ Rule 12-16 may result in NOx emissions that would exceed the significance thresholds resulting in potentially significant air quality impacts.	Develop a Construction Emission Management Plan; to minimize emissions from vehicles and trucks; limit truck idling; maintain construction equipment to manufacturer's recommendations; identify construction areas served by electricity; Use cranes rate 200 hp or greater with Tier 4 engines or equivalent (if available); and use off-road equipment rated 50 to 200 hp with Tier 4 or equivalent engines (if available).	NOx emissions during construction activities are potentially significant under ~~Rules 11-18 and Rules~~ Rule 12-16 following mitigation, but would cease when construction activities are complete.
Construction activities that may be required to implement Rule ~~11-18 and Rules~~ 12-16 are expected to result in emissions of ROG, PM10 and PM2.5 that would be less than significant.	None Required	Construction emissions of ROG, PM10 and PM2.5 would be less than significant under ~~Rules 11-18 and~~ Rule 12-16.
~~The annual NOx emission threshold may be exceed due to implementation of Rule 11-18.~~	~~None identified for the control of emissions from air pollution control equipment as the equipment is considered BACT.~~	~~Operational emissions of NOx would remain significant due to implementation of Rule 11-18.~~
The NOx emission thresholds exceed due to implementation of Rule 12-16 are not expected to be exceeded.	None Required	Operational emissions of NOx would be less than significant due to implementation of Rule 12-16.
Operational activities that may be required to implement Rule ~~11-18 and Rules~~ 12-16 are expected to result in emissions of ROG, PM10 and PM2.5 that would be less than significant.	None Required	Operational emissions of ROG, PM10 and PM2.5 would be less than significant.
TAC emissions associated with implementation of Rule ~~11-18 and~~ 12-16 are expected to be less than significant.	None Required	Potential TAC emissions under ~~Rules 11-18 and~~ Rule 12-16 are less than significant.

TABLE 1-1

Summary of Environmental Impacts, Mitigation Measures and Residual Impacts

Impact	Mitigation Measures	Residual Impacts
Greenhouse Gas Emissions		
~~Air pollution control technologies that would most likely be implemented under Rule 11-18 could generate GHG emission impacts that would be considered significant.~~	~~None identified but some GHG emissions may be offset under the AB32 Cap and Trade Program. .~~	~~GHG emissions are expected to remain significant under Rule 11-18.~~
Air pollution control technologies that would most likely be implemented under Rule 12-16 is expected to generate GHG emission that would be considered less than significant.	None Required.	GHG emissions are expected to be less than significant under Rule 12-16.
Hazards and Hazardous Materials		
Fire or explosion impacts from the use of baghouses under ~~Rules~~ Rule 12-16 ~~or 11-18~~ are potentially significant.	Mitigation measures include a comprehensive dust control program; ground filter elements; install explosion rupture panels; remove dusts from filters prior to replacing filters; perform hot work away from collectors; do not use power tools in areas with high dust concentrations; and ensure adherence to applicable NFPA standards.	Hazards impacts from the use of baghouses are expected to be less than significant following mitigation.
Fire or explosion impacts from the use of dry ESPs under Rule 12-16 are potentially significant.	Mitigation measures include using CO sensors; digital electronic controls; covering wires with shrouds; and conduct routine inspections. None required.	Hazards associated with the use of dry ESPs are expected to be less than significant following mitigation.
Transportation and use of hazardous materials in SCRs and WGS are expected to remain less than significant under ~~11-18 and/or~~ Rule 12-16	None Required	Transportation and use of hazardous materials would remain less than significant.
Hydrology and Water Quality		
The potential water demand created by the need for new air pollution control equipment, particularly wet gas scrubbers, would result in a significant impact on water demand associated with ~~both~~ ~~Rules 11-18 and~~ Rule 12-16.	Mitigation measures include the requirement to use recycled water, if available.	Water demand impacts are expected to remain significant under ~~both~~ ~~Rules 11-18 and~~ Rule 12-16.

TABLE 1-1

Summary of Environmental Impacts, Mitigation Measures and Residual Impacts

Impact	Mitigation Measures	Residual Impacts
Wastewater generated from the installation of air pollution control equipment to comply with ~~Rules 11-18 and~~ Rule 12-16 are not expected to exceed any applicable water quality significance thresholds. Therefore, no wastewater impacts are expected.	None required.	Wastewater impacts are expected to remain less than significant.

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Mr Douglas,
According to 1.4.1 AIR Quality, 1.4.1.1 Air Quality Setting, the second paragraph states that the Eastern District is designated as non-attainment area (**nonattainment** area is an area considered to have air quality **worse** than the National Ambient Air Quality Standards as defined in the Clean Air Act Amendments of 1970) yet on Table 3.2-2 there is lacking or missing emissions information for **Bethal Island** (no PM), **Crockett** (lacking info.), **Fairfield** (lacking info. and no PM), **Martinez** (lacking info. and no PM), **Patterson Pass** (Lacking info. and no PM) and San Ramone(lacking info. and no PM).

- Why has this information been omitted?
- How does the BAAQMD base a decision with incomplete information?
- Why is no Emmissions data available for the city of Martinez and Richmond where refineries are located

Thank you for your time,
Christopher Potter

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May 8, 2017

Mr. Victor Douglas
Principal Air Quality Engineer
Bay Area Air Quality Management District
375 Beale Street, Suite 600
San Francisco, CA 94105

RE: Draft Environmental Impact Report for Proposed Rules 11-18 and 12-16

Dear Mr. Douglas,

On behalf of the members of the California Council for Environmental and Economic Balance (CCEEB), we provide comments on the proposed Draft Environmental Impact Report (DEIR) for proposed Regulation 11, Rule 18 (Rule 11-18) and Regulation 12, Rule 16 (Rule 12-16) and supporting documentation. CCEEB is a coalition of business, labor, and public leaders that advances strategies for a sound economy and a healthy environment. CCEEB represents a large number sources that operate facilities in the air basin and in the State.

The EIR is "the heart of CEQA." *Laurel Heights Improvement Ass'n v. Regents of Univ. of Cal.* (1988) 47 Cal.3d 376, 392. It is "an environmental 'alarm bell' whose purpose it is to alert the public and its responsible officials to environmental changes before they have reached ecological points of no return. The EIR is also intended 'to demonstrate to an apprehensive citizenry that the agency has, in fact, analyzed and considered the ecological implications of its action.' Because the EIR must be certified or rejected by public officials, it is a document of accountability." *Id.* The multitude of drafting errors in the Draft EIR (DEIR) and the lack of consistency between the Project as described in the DEIR and as described in the current draft of proposed Rule 11-18 make the DEIR nearly impossible to understand or comment upon. Much of the document is incoherent or the description of the project so inconsistent with the draft proposed rule, that it is difficult to understand the impact analysis, let alone comment on it. This is a clear violation of CEQA's mandate for clear and concise information.

We highlight some specific errors below to illustrate this point.

Project Description

The "fundamental purpose of an EIR 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.'" *Vineyard Area Citizens for Responsible Growth v. City of Rancho Cordova* (2007) 40 Cal.4th 412, 428 (emphasis added). In order for an EIR to adequately evaluate the environmental ramifications of a project, it must first provide a comprehensive description of the project itself.

"An accurate, stable and finite project description is the *sine qua non* of an informative and legally sufficient EIR." *San Joaquin Raptor/Wildlife Rescue Center v. County of Stanislaus* (1994) 27 Cal.App.4th 713, 730 (quoting *County of Inyo v. City of Los Angeles* (1977) 71 Cal.App.3d 185, 193). An accurate project description is "the heart of the EIR process" and "necessary for an intelligent evaluation of the potential environmental effects of a proposed activity." *Sacramento Old City Ass'n. v. City Council* (1991) 229 Cal.App.3d 1011, 1023; *San Joaquin Raptor/Wildlife Rescue Center,* 27 Cal.App.4th at 730. While extensive detail is not necessary, the law requires that EIRs describe proposed projects with sufficient detail and accuracy to permit informed decision making. *See* CEQA Guidelines § 15124 (project description). Thus, a vague, inaccurate, or incomplete project description renders the analysis of significant environmental impacts inherently unreliable. Consequently, courts have found that, even if an EIR is adequate in all other respects, the use of a "truncated project concept" mandates the conclusion that the lead agency did not proceed in a manner required by law. *San Joaquin Raptor/Wildlife Rescue Center*, 27 Cal.App.4th at 730.

Here, the DEIR does not come close to meeting the established legal standards for an accurate project description. As to proposed Rule 11-18 specifically, the DEIR is based on the initial draft rule, as released on October 14, 2016, and the accompanying *Draft Staff Report*. In comments to staff, sent on December 2, 2016, we raised a number of outstanding issues with the draft rule. We have not received a response to our comments, nor has staff released comments made by other stakeholders. It is our understanding that work is continuing on the draft rule, and because of the work still needed on the draft rule, this DEIR is premature.

The inconsistencies between the DEIR and the current version of proposed Rule 11-18, and with the knowledge that the District will later release a new version of the draft rule, and the lack of clarity in describing the proposed rules, make the DEIR fail as an informational document under CEQA. *Sacramento Old City Ass'n. v. City Council* (1991) 229 Cal.App.3d 1011, 1023. Further, to the extent that changes are made to the draft rule, we expect that further environmental review and revisions to the DEIR will be made and the DEIR recirculated as required under CEQA.

The failure to wait to undertake environmental review until a stable project description exists creates CEQA issues that cascade through the document. There are many gaps in the DEIR regarding potential impacts that staff find too speculative to include in its analysis. In some key instances, we disagree with staff's opinion, and believe the DEIR is incomplete in part because proposed Reg. 11-18 is incomplete. While meeting its rule adoption schedule is of interest to the District, it should not be, and legally cannot be, used as justification for an inadequate CEQA analysis.

Section 2.4.2.1.1: Administrative Procedures

The Draft EIR states that, for proposed Rule 11-18, staff will conduct a Health Risk Screening Analysis (HRSA) based upon annual toxic emissions inventories reported to the District. The HRSA would be used to prioritize a facility and assign it to one of four "Implementation Phases" that dictate compliance schedules. Staff would then conduct Health Risk Assessments (HRAs) for each facility, with the results used to determine whether a facility had triggered risk action levels requiring a risk reduction plan. Thus, in the DEIR, the District makes a material distinction between an HRSA and an HRA. The DEIR then states that a facility has five years to implement risk reductions.

Throughout this section, the DEIR is inconsistent with the draft rule. First, in Rule 11-18, there is no reference to District annual reporting requirements or a facility's annual toxic emissions inventory. Yet the DEIR states, "Air District staff believes that new facility-wide HRAs should be performed including improved emission inventories…." It is not clear what changes to emission reporting and inventory calculations staff foresees, or how these changes would be implemented.

Second, Rule 11-18 contains a vague definition of "Health Risk Screening Analysis" and moreover, Regulation 2, Rule 5 was recently amended to strike the definition of "HRSA" and replace it with a definition of "Health Risk Assessment." Throughout Rule 2-5, the term HRSA was universally replaced with HRA.[1] That is, under Reg. 2-5, an HRSA and HRA are fundamentally the same thing and not different steps or methods of analysis, as implied in the DEIR (the District no longer defines or uses the term HRSA in any of its rules).

Additionally, no significance criteria for toxic air contaminants (TACs) (i.e. cancer risk, acute and chronic HI) are included in the DEIR. It is not possible to properly determine impacts if there are no significance criteria. Page 3.2-47 claims that increased ammonia emissions resulting in increased acute and chronic HI would be less than significant, but no significance threshold is shown. The District needs to include significance criteria in

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[1] Regulation 2, Rule 5 Staff Report, page 22: "Section 2-5-211: Health Risk Screening Analysis: The Air District is proposing to change the term and acronym 'Health Risk Screening Analysis (HRSA)' to 'Health Risk Assessment (HRA)' for consistency with OEHHA's terminology."

the DEIR with a discussion detailing why the criteria proposed is relevant. The EIR will be deficient without the significance criteria.

Third, and most importantly, the DEIR states that a facility has five years to reduce risks once a risk reduction plan has been approved. This contradicts Section 11-18-402, which states that a facility must get below the risk action level “as soon as feasible but by no later than *three (3) years* from the date of *submission*.” [Emphasis added.]

In no way is the description of proposed Rule 11-18 in this section of the Project Description of the DEIR “[a]n accurate, stable and finite project description.” *San Joaquin Raptor/Wildlife Rescue Center v. County of Stanislaus* (1994) 27 Cal.App.4th 713, 730 (quoting *County of Inyo v. City of Los Angeles* (1977) 71 Cal.App.3d 185, 193).

Section 2.4.2.1.4: Source Coverage

The DEIR correctly states that Rule 11-18 would apply to a wide variety of stationary sources, “…including data centers, petroleum refineries, chemical plants, wastewater treatment facilities, foundries, forges, landfill operations, hospitals, crematoria, gasoline dispensing facilities (i.e., gasoline stations), colleges and universities, military facilities and installations and airline operations.” Section 1.3.3.1 has a similar but slightly different list which adds cement manufacturing, power plants, and manufacturing facilities. However, neither section mentions several additional and important facility types that would also be regulated under the rule, including:

- Commercial and institutional buildings
- Commercial construction
- Correctional institutions
- Fire stations
- Food and beverage processors
- Hotels
- K-12 schools
- Multifamily residential buildings
- Research and development centers
- Retail stores
- Telecommunication carriers
- Television broadcasting stations
- Transportation and transit facilities
- Water supply and irrigation agencies

Table 2.5-1 also omits these additional sectors. The failure to comprehensively explain the rule, and which facilities it would apply to, is in contradiction to CEQA’s requirement that EIRs describe proposed projects with sufficient detail and accuracy to permit informed decision making. *See* CEQA Guidelines § 15124 (project description). The DEIR does not describe the Project in sufficient detail to allow for appropriate environmental analysis.

CCEEB also believes that analysis of risk reduction projects, including construction and operational impacts, may be warranted for some of these missing sectors, particularly for those that provide essential public services or where public safety could be factor. Similarly, as staff develops the socioeconomic impact analysis for draft Rule 11-18, we believe these additional sectors should be included.

Section 2.5: Sources Affected and Applicable Control Technologies
Section 2.5 states, "It is not specifically known what types of equipment would be affected by either rule." However, for Rule 11-18, we believe the potential risk reduction strategies and control equipment are reasonably foreseeable—and thus, able to be analyzed for the purposes of the EIR—but that the District has not yet completed the requisite engineering analysis. For example, Rule 11-18 could require installation of Best Available Retrofit Control Technology for Toxics (TBARCT), as defined in Section 11-18-204 of the rule. However, staff has yet to release guidance on what would be considered TBARCT for specific sources. Such documentation is of particular importance for Rule 11-18 because the classification of TBARCT is novel and wholly unique to this rule (i.e., no other air agency in the nation defines or applies TBARCT).[2]

The District will need to conduct its engineering analysis at some point in the near future to support implementation and enforcement of Rule 11-18. As such, it could be better said that it is not specifically known *at this time* what types of equipment would be affected. Indeed, the following subsections of the DEIR go on to describe affected equipment for select sectors, suggesting staff work in progress. If the District cannot say with certainty which sources will be affected by the rules and what potentially applicable control technologies will be used to comply, how can it conduct a legally sufficient analysis of the Project's potential environmental impacts? In its haste to proceed with rulemaking, the District has pushed the DEIR forward with an incomplete engineering analysis, no attempt to identify affected sources, no potential compliance options, and thus a vague and unclear analysis of the potential environmental impacts from risk reduction projects and other methods of compliance with the proposed rules. CEQA requires more.

CEQA requires public agencies to evaluate a Project's impacts to the extent "reasonably feasible" and an EIR must make a "good faith effort at full disclosure." CEQA Guidelines § 15151. There is no good faith effort to disclose when the DEIR is proceeding ahead of rule development and thus a stable project description, from which all of the impact analyses are derived, is lacking.

Here, the DEIR's project description is vague, inaccurate, and incomplete and this renders the analysis of significant environmental impacts inherently unreliable. Courts have found that, even if an EIR is adequate in all other respects, the use of a "truncated

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[2] Conversely, the District provides great detail about what is considered Best Available Control Technology for Toxics (TBACT) for each source under Regulation 2, Rule 5. See the BAAQMD Permitting Manual: TBACT Workbook at http://www.baaqmd.gov/permits/permitting-manuals/bact-tbact-workbook.

project concept" mandates the conclusion that the lead agency did not proceed in a manner required by law. *San Joaquin Raptor/Wildlife Rescue Center,* 27 Cal.App.4th at 730. The District must revise and recirculate the DEIR in order to address the myriad issues with the project description.

Impact Analysis and Mitigation Measures

Where, as here, the DEIR fails to fully and accurately inform decision makers, and the public, of the environmental consequences of proposed actions, it does not satisfy the basic goals of the statute. See Pub. Res. Code § 21061 ("The purpose of an environmental impact report is to provide public agencies and the public in general with detailed information about the effect that 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.") Specific issues with the environmental analysis in the DEIR are discussed below.

Sections 1.4.4.2 and 3.5: Hydrology and Water Quality Impacts

The DEIR notes that the use of certain control equipment, such as wet gas scrubbers, would increase water demand and wastewater treatment. The DEIR finds this impact to be significant and implements mitigation measures (HWQ-1 and HWQ-2) that will not reduce the impact to a level of insignificance. These mitigation options are "cursorily described," are "nonexclusive, undefined, untested and of unknown efficacy," and create "no objective criteria for measuring success." (*Communities for a Better Environment v. City of Richmond*, 184 Cal.App.4th, 93). CEQA requires lead agencies to identify and analyze all feasible mitigation, even if this mitigation will not reduce the impact to a level of insignificance. CEQA Guidelines § 15126.4(a)(l)(A).

In addition, this analysis omits an analysis of the impacts from Rule 11-18 on operations and service levels at water agencies and wastewater treatment plants, which are likely to be subject to rule requirements. If risk reduction projects at these types of facilities could result in changes to water supply or wastewater treatment, these impacts must be included in DEIR's analysis.

Sections 3.3.5 and 3.3.5.2: Greenhouse Gases

Section 3.3.5 states, "Operational GHG emission increase would be offset it they occurred at facilities that are included in the Cap and Trade Program. However, since there is no specific information as to where the air pollution control equipment would occur it would be speculative to assume that GHG emissions would be offset under the AB 32 Cap and Trade Program at this time. Nonetheless, some or all of the GHG emission that may be generated to comply with Regulations 11-18 and 12-16 would be offset under the Cap and Trade Program." From this, it is unclear whether staff assumes GHG emissions increases would or would not be mitigated under Cap and Trade.

The following Section 3.3.5.2 then reiterates that emissions reductions under Cap and Trade are speculative and, thus, Rule 11-18, whether alone or in combination with Rule 12-16, would result in significant cumulative GHG emissions. This only adds to the confusion. This confusing analysis violates CEQA's core informational purpose. *Mira Monte Homeowners Assn. v. County of Ventura* (1985) 165 Cal.App.3d 357, 365 (EIR protects "the right of the public to be informed in such a way that it can intelligently weigh the environmental consequences of a [] contemplated action").

Alternatives Analysis

Under CEQA, a proper analysis of alternatives is essential to comply with the Act's mandate that significant environmental impacts be avoided or substantially lessened where feasible. Pub. Res. Code § 21002; CEQA Guidelines §§ 15002(a)(3), 15021(a)(2), 15126(d); *Citizens for Quality Growth v. City of Mount Shasta* (1988) 198 Cal.App.3d 433, 443-45. Indeed, the analysis of alternatives lies at the "core of an EIR." *Citizens of Goleta Valley v. Board of Supervisors* (1990) 52 Cal.3d 553, 564. A major goal of any EIR is to "ensure that all reasonable alternatives to proposed projects are thoroughly assessed by the responsible official." *San Joaquin Raptor/Wildlife Rescue Center v. County of Stanislaus* (1994) 27 Cal.App.4th 713, 735; *see also* Cal. Pub. Res. Code § 21002.1(a). As stated in *Laurel Heights Improvement Association*, "[w]ithout meaningful analysis of alternatives in the DEIR, neither the courts nor the public can fulfill their proper roles in the CEQA process . . . . [Courts will not] countenance a result that would require blind trust by the public, especially in light of CEQA's fundamental goal that the public be fully informed as to the consequences of action by their public officials." 47 Cal.3d at 404.

Sections 1.5 and 4.0

Conjoining proposed Rules 11-18 and 12-16 in a single environmental impact report presents challenges, especially in regards to possible alternatives. Staff ultimately considered four alternatives: two "no-project" and two "project alternatives," listed in the table below. In reality, the BAAQMD Board could choose to adopt a different combination of rules and/or alternatives than the six presented in the report.

11-18 as proposed	Alt 1.1. 11-18 no project	Alt. 1.2 11-18 25x10-6
12-16 as proposed	Alt. 2.1 12-16 no project	Alt. 2.2 11-18 as proposed + 13-1

Properly developing, evaluating, and comparing project alternatives are key to the environmental review process. The District must identify and "consider a reasonable range of potentially feasible alternatives that will foster informed decision making and public participation." CEQA Guidelines, § 15126.6(a). This range must include alternatives that "feasibly attain most of the basic objectives of the project but would avoid or substantially lessen any of the significant effects of the project." Id. The

District's failure to include as alternatives each permutation of possible rule combinations is fatal to its analysis in the DEIR.

Beyond the irregularity of analyzing two rules in a single EIR, CCEEB is further concerned that Regulation 13, Rule 1 is proposed as part of Alternative 2.2. Proposed Rule 13-1 is in the early stages of development and not part of the DEIR. At this time, it is unclear how refineries would comply with the carbon-intensity limit in Rule 13-1, and as a consequence, we find the alternatives analysis for alternative 2.2 to be highly speculative.

Alternative 1.2: Rule 11-18 with a 25 x 10^6 Risk Reduction Threshold

The DEIR notes that when applying a 25-in-a-million risk reduction threshold—which would be consistent with limits in the South Coast and San Joaquin Valley—the reach of the rule would be reduced from 1,000 to about 86 facilities. "Under this alternative, the number of individuals that remain exposed to elevated health risk levels posed by these facilities would be much greater than that under the proposal."[3] CCEEB asks for greater clarity on this point, especially in terms of how many additional individuals would be exposed to an "elevated" health risk level. We note two issues here. First, as the DEIR indicates, there are no levels of exposure to carcinogens without some risk of cancer, even if the risk is so low as to be practically meaningless. Because of this, the BAAQMD Board must decide what is an *acceptable* level of risk, asking what are the actual marginal health benefits from a 10x10^6 threshold vs. 25x10^6 threshold, at what cost to regional businesses, agencies, and the economy, and at what potential impacts to the environmental exist based on potential compliance methods.

Second, because Rule 11-18 only controls stationary sources, it does nothing to change area and mobile sources, which drive the preponderance of risk in the region. Indeed, industrial and commercial equipment account for only six percent of cancer-weighted air toxic emissions. Thus, even if risk from *all* stationary sources were reduced to zero, overall lifetime cancer risk from air toxics would still be about 650-in-a-million or about 0.0065 percent,[4] down from a 690-in-a-million risk. Since Rule 11-18 proposes a risk reduction threshold higher than zero, the resulting change in overall cancer risk would be even less. For this reason, the actual marginal benefit between proposed Rule 11-18 and its Alternative 1.2 is nominal. Merely stating how many facilities are affected by the regulation oversimplifies the analysis of the environmental differences between the proposed rule and Alternative 1.2.

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[3] Page 1-15.

[4] To put this in perspective, total lifetime cancer risk from all causes is about 40 percent.

Cumulative Impacts

The cumulative impacts analysis is similarly flawed. Under the CEQA Guidelines, "a cumulative impact consists of an impact which is created as a result of the combination of the project evaluated in the EIR together with other projects causing related impacts" CEQA Guidelines § 15130(a)(1). Because "[c]umulative impacts can result from individually minor but collectively significant projects" (CEQA Guidelines 15355(b)), an impact that appears less than significant (or mitigable to such a level) when only the project is scrutinized may turn out to contribute to a significant cumulative impact. In that case, the EIR must determine whether the project's contribution is "cumulatively considerable," that is, whether its "incremental effects . . . are significant when viewed in connection with the effects of past projects, the effects of other current projects, and the effects of probable future projects." CEQA Guidelines § 15065(a)(3).

Sections 3.1.5 and 3.2.6

Section 3.1.5 of the DEIR on states, "[T]his EIR evaluates the cumulative impacts associated with a variety of regulatory activities. As such, this EIR evaluates the cumulative environmental impacts associated with implementation of other air quality regulations as outlined in the 2017 Clean Air Plan, the most recent air plan for the Bay Area (BAAQMD, 2017)." No mention is made of either Rule 11-18, 12-16 or 13-1 in this section.

Section 3.2.6 later explains that, "With regard to related projects or projects with related environmental impacts, because the proposed project consists of promulgating either Rule 11-18, Rule 12-16, or both, related projects would consist of other past, present, and future BAAQMD rules and regulations, as well as implementing control measures in the 2017 Clean Air Plan control measures." [sic]

It is unclear whether the analysis is analyzing the proposed project in conjunction with proposed rule 13-1, analyzing both rules 11-18 and 12-16 in conjunction with proposed rule 13-1, or neither. The DEIR must be revised to clarify the cumulative analysis undertaken in the document and include all reasonably foreseeable future projects (such as proposed Rule 13-1) in that analysis.

General Comments

CCEEB agrees with the DEIR that, "All major stationary sources of GHG are included under a statewide cap created by CARB's Cap-and-Trade rule. The total GHG emissions from all sources combined is required to decline over time to meet statewide GHG reduction goals. Since any local caps in the Bay Area would not reduce the total allowable GHG emissions under a statewide cap, it's unclear how local caps would benefit global climate."[5] The report goes on to say, "…the facilities that would be subject

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[5] Page 2-41.

to draft Rule 12-16 are already subject to GHG emissions reduction requirements pursuant to the statewide AB 32 Cap-and-Trade system. Consequently, GHG emission reductions would occur regardless of whether or not draft Rule 12-16 is adopted."[6]

As the DEIR points out, mandating GHG reductions at capped facilities merely shifts those emissions to other facilities (creating leakage), whereas any increase in GHG emissions at a facility is mitigated under the Cap-and-Trade program. This same problem of duplication and overlap applies to Regulation 13, Rule 1 and should be considered in any CEQA document assessing that proposed rule.

Thank you for the opportunity to submit these comments. CCEEB will likely have further feedback as we work to further understand the implications of the EIR for Rules 11-18 and 12-16. In the meantime, we welcome any questions you may have. Please feel free to contact me at billq@cceeb.org and 415-512-7890 ext. 115, or my colleague Janet Whittick at janetw@cceeb.org and ext. 111.

Sincerely,

Bill Quinn

Bill Quinn
CCEEB Chief Operating Officer and Bay Area Partnership Project Manager

cc: Mr. Gerald D. Secundy, CCEEB
Ms. Janet Whittick, CCEEB
Greg Nudd, BAAQMD

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[6] Ibid.

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May 8, 2017

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VIA EMAIL

Mr. Victor Douglas
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Re: Comments on Draft Environmental Impact Report (SCH #2016102043) For Proposed Air District Regulations 11-18 and 12-16

Dear Mr. Douglas:

We appreciate this opportunity to submit comments on behalf of Chevron U.S.A. Inc. on the Draft Environmental Impact Report prepared by the Bay Area Air Quality Management District addressing two proposed Air District regulations: Regulation 11-18, Toxic Risk Reduction Rule, and Regulation 12-16, Petroleum Refining Emissions Limits and Risk Thresholds.

Chevron appreciates the Air District's mission in protecting the air quality of the Bay Area and its residents. We also understand the concerns of the California Air Resources Board, the Air District, and the public about emissions of greenhouse gases and the effects of climate change. Further, we value our longstanding role as a member in this community.

It is in this context that we express our concerns that the Air District's current rulemaking proposals do not adequately recognize the environmental, economic and social trade-offs that are involved and the unintended negative consequences that the proposed regulations may have. For example, as recognized in the Staff Report prepared by Air District staff, the imposition of emissions caps at individual facilities may have broader impacts in terms of constraining the statewide market for transportation fuels, thereby leading to increased transport of fuels from other locations to meet demand. This unintended chain of events could actually increase GHG emissions statewide rather than reducing them, and also could increase emissions of criteria air pollutants and toxic air contaminants in California's bays and harbors due to increased shipments of fuels. Further, the imposition of emissions caps at individual facilities could prevent the future installation and operation of new technologies and equipment at those facilities, where these innovations could make fuels cleaner and thereby help to achieve substantial reductions in emissions from mobile sources across the state, but also could result in small emissions increases at the facilities that would be prohibited because of an inflexible regulatory cap. These trade-offs can be complex and difficult and we are concerned that the current regulatory proposals may be environmentally counter-productive in the long run. We would like to make sure that the big-picture environmental effects and trade-offs of the Air District's proposals are thoroughly and carefully vetted before a final decision is made that could trigger a chain of unfortunate and unintended consequences.

It is for these reasons that we share the concerns about Air District's proposed regulations that have been raised by the Western States Petroleum Association. One of the important concerns identified by WSPA is that the Air District has segmented its analysis under the California Environmental Quality Act of its proposed regulatory program as a whole for addressing refinery emissions, and that the Air District is dividing up its review of this overall program into smaller pieces, which has the effect of preventing a clear and comprehensive understanding of the adverse environmental consequences that the Air District's adoption of this program could cause.

In addition to this "piecemealing" problem, our review has identified several additional CEQA issues with the Draft EIR. In order to fulfill CEQA's goals of fostering informed decision-making and meaningful public participation, we respectfully maintain that the Air District should revise the environmental analysis in the Draft EIR and then recirculate the revised analysis in a new draft EIR for another round of public review and comment.

In particular, our review has revealed the following issues with the environmental analysis the Draft EIR, each of which is addressed separately in the sections below:

- The environmental analysis should recognize and evaluate the potentially significant climate change and air quality effects that could result from the adoption of proposed Regulation 12-16. The March 2017 Staff Report touches on some of the problems that could arise if there is a constraint on the market for transportation fuels.

- The Draft EIR should explain more thoroughly how adoption of the proposed regulations could contribute to significant cumulative environmental impacts, including cumulative impacts on air quality and water supplies.

- The Draft EIR should evaluate the negative impacts that proposed Regulation 12-16 could have in terms of preventing future projects that may provide important environmental benefits, but that would be precluded as a result of the fixed emissions caps that would be imposed under the regulation.

- In order to better understand the regulatory options available to the Air District, the Draft EIR should explore a broader range of alternatives to proposed Regulation 11-18.

- Lastly, the Draft EIR does not support a finding that proposed Regulation 12-16 may be approved, particularly in light of the significant and unavoidable environmental impacts that the regulation would cause.

1. The Draft EIR Ignores Potentially Significant Climate Change and Air Quality Impacts From Regulation 12-16

The Air District's March 2017 Staff Report for Regulation 12-16 indicates that there are two potential scenarios to consider when evaluating the impacts of capping refinery emissions. According to the Staff Report, one scenario is that the refineries would make physical improvements in order to reduce emissions to allow for potential increases in refinery capacity while staying below the applicable emissions caps. The Draft EIR focuses on this scenario, evaluating the types of physical equipment improvements that may be necessary to comply with the emissions caps and the potential environmental impacts from constructing and operating the improvements. The Draft EIR finds that the caps under Regulation 12-16 would lead to significant and unavoidable air quality impacts from construction activities to undertake the physical equipment improvements and significant and unavoidable water demand impacts from continued operation of the equipment.

But the Air District's Staff Report also outlines a second potential scenario, under which refineries would be forced to limit their production in order to meet the applicable caps. As the Air District has explained, while the baseline refinery production levels that were used to establish the caps reflected "years of relatively low gasoline consumption in California," there has been a recent trend of increasing consumption. (Staff Report, at p. 31; Draft EIR, at p. 3.3-27.) The Staff Report explains that if this trend of increasing demand continues, the emissions caps under proposed Regulation 12-16 "may end up being a significant constraint on the market." (Staff Report, at p. 32.)

The Staff Report further explains that a significant constraint on the market similarly could occur "if overall statewide refining capacity is reduced." (*Id.*) The Staff Report points to a recent example of this phenomenon – namely, the shutdown in 2015 of the ExxonMobil refinery in Torrance, California. While this shutdown of a single California refinery resulted in only a modest 10 percent reduction in fuel supply, "imports of refined products increased ten-fold, ***resulting in additional GHG impacts from shipping***." (*Id.*, emphasis added.) Based on the effects from shutdown, the Staff Report cautioned that "when the supply of fuels is constrained, the impacts can be dramatic and statewide." (*Id.*) The Staff Report concluded that Rule 12-16 may have a significant effect on the Bay Area and the rest of California "if statewide refinery capacity was significantly reduced due to a refinery closure or incident similar to the 2015 ExxonMobil incident." (*Id.*)

The increased imports of fuels into California to make up for the supply shortfall resulting from the Torrance shutdown came from all over the world, including from Russia, India and Europe.[1]

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Because of its unique product specifications and the long distance from international gasoline markets, California (and the West Coast more generally) does not typically import much gasoline. As a result, the state's ability to increase output of refined petroleum products in response to rapid changes in demand is an important mechanism of flexibility, and a reduction in this "surge" capability could artificially constrain supply for the California transportation fuels market.[2]

In turn, having to increase the import of fuels from places such as Russia, India and Europe results in increased GHG emissions, as well as increased emissions of both criteria pollutants and toxic air pollutants, due to the increased ship traffic in the bays, waters and harbors of the state and the associated truck trips.

Despite the important discussion in the Air District's Staff Report about the increased GHG emissions that already have resulted from supply constraints in California – and the significant potential for such supply constraints to occur again as a result of the emissions caps under Regulation 12-16 – the Draft EIR states that any effort to evaluate this issue "results in unreasonable levels of speculation." (Draft EIR, at p. 3.3-27.) But the Staff Report shows that the Draft EIR can and should evaluate the proposed regulation's potential to constrain supply and thereby increase GHG emissions, and that this type of environmental consequence, which transpired only a few short years ago, is reasonably foreseeable. It is important that both the public and the decision-makers are fully informed about the potential adverse consequences of the proposed regulation.

In our view, it seems to be inconsistent for the Draft EIR to state that one of the objectives of proposed Regulation 12-16 is to prevent increases in refinery emissions that could occur due to increases in oil feed quantity, while at the same time claiming it is not possible to study the environmental consequences, identified by the Air District's staff report, that could result from doing just that – limiting increases in oil feed quantity. In other words, it appears that the Draft EIR has not studied the very impacts that could result from achieving one of the basic objectives of the proposed project.

Another objective of proposed Regulation 12-16 is to prevent increases in refinery emissions that could occur due to changes in oil feed quality or that could occur due to an increase in the emissions intensity of the production of transportation fuels. However, the Draft EIR does not provide a clear description of how changes in oil feed quality would result in increased emissions or of what the emissions increases could be. As a result, the decision-makers and the public do not have a clear basis upon which to weigh the environmental impacts of the proposed regulation

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against the environmental benefits, or to assess how the proposed regulation could affect future refinery operations or how it would or would not achieve the stated project objectives.

In sum, the Draft EIR should be revised to provide a thorough and careful evaluation of the potential climate change and air quality effects that the emissions caps in Regulation 12-16 could cause by constraining the state's supply of transportation fuels. To provide a meaningful opportunity for public review, the revised analysis should then be presented in a recirculated draft EIR.

2. The Cumulative Impact Analysis Is Inadequate

CEQA requires that an EIR discuss whether and how the incremental effects of a proposed project would be significant when viewed in connection with the effects of past projects, the effects of other current projects, and the effects of probable future projects. CEQA Guidelines §§ 15064(h)(1), 15065(a)(3), 15130. As specified by Section 15130 of the CEQA Guidelines, the following elements are necessary to an adequate discussion of cumulative impacts:

> (1) Either (A) A list of past, present, and probable future projects producing related or cumulative impacts, including, if necessary, those projects outside the control of the agency, or (B) A summary of projections contained in an adopted general plan or related planning document, or in a prior environmental document which has been adopted or certified, which described or evaluated regional or areawide conditions contributing to the cumulative impact. Any such planning document shall be referenced and made available to the public at a location specified by the lead agency.
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> (2) When utilizing a list under (1)(B) above, factors to consider when determining whether to include a related project should include the nature of each environmental resource being examined, the location of the project and its type.
>
> (3) Lead agencies should define the geographic scope of the area affected by the cumulative effect and provide a reasonable explanation for the geographic limitation used.
>
> (4) A summary of the expected environmental effects to be produced by those projects with specific reference to additional information stating where that information is available.
>
> (5) A reasonable analysis of the cumulative impacts of the relevant projects.

Here, the short discussion of cumulative impacts in the Draft EIR does not reveal to the public and the decision-makers the serious consequences that could occur as a result of adopting the proposed regulations in conjunction with the effects of other past, present and reasonably foreseeable Air District regulations and control measures. For example, the introductory discussion of cumulative impacts states merely that the EIR "evaluates the cumulative environmental impacts associated with implementation of other air quality regulations as outlined in the 2017 Clean Air Plan." (Draft EIR, at p. 3.1-4.) The introduction to the discussion of cumulative air quality impacts similarly states that "related projects would consist of other past, present, and probable future BAAQMD rules and regulations, as well as implementing control measures in the 2017 Clean Air Plan." (Draft EIR at pp. 3.2-52 to 3.2-53.)

The Draft EIR then discusses the cumulative air quality impacts, but the discussion, which totals little more than one page of text, does not contain sufficient detail as to what the combined effects could be. There is no description of the related projects that bear on the air quality impacts of the two proposed regulations, no assessment of what the air quality impacts of these related projects are or could be, and no evaluation of how the effects associated with the two proposed regulations would interact or aggregate with the impacts from the related projects. (*Id.* at pp. 3.2-53 to 3.2-54.)

The discussion of cumulative water demand impacts similarly lacks meaningful content. This discussion, which totals two short paragraphs of text, simply reiterates the Draft EIR's prior conclusions regarding the project-specific impacts of the two proposed regulations, without any discussion of the specific items that are required under the CEQA Guidelines for an adequate evaluation of cumulative impacts. There is no reference to any of the related projects, let alone how the project-specific water demand impacts of the two proposed regulations, which are found to be significant and unavoidable, would interact or aggregate with the related projects' impacts on water usage and demand. (*Id.* at p. 3.5-23.)

In sum, the cumulative impact discussion in the Draft EIR should be revised to present a clearer picture of what the combined impacts could be from the proposed regulations together with other past, present and reasonably foreseeable future Air District rules and control measures. The revised analysis should then be presented in a recirculated draft EIR, so that there is a meaningful opportunity for public review.

3. The Draft EIR Fails to Evaluate the Negative Impacts that Proposed Regulation 12-16 Could Cause by Preventing Environmentally Beneficial Projects

One of California's climate change strategies, as embodied in the 2017 Climate Change Scoping Plan Update prepared by the California Air Resources Board, is the production of cleaner fuels to reduce GHG emissions from mobile sources. Mobile sources create nearly 50 percent of GHG emissions in the state, as well as 80 percent of emissions of oxides of nitrogen and 90 percent of particulate matter emissions. To produce cleaner fuels to advance the state's goals, new equipment likely will be needed at California refineries. Further, the operation of this new equipment likely will result in an increase in some stationary source emissions at the refineries. For example, such new equipment could cause some increases in GHG and other emissions at the refineries due to construction activities to install the equipment and the continued operation of the equipment as part of the refinery processes, while at the same time contributing to dramatic and important reductions in statewide emissions of GHGs from mobile sources.

California has in the past experienced a similar example of this phenomenon. In the mid-1990s, California state law required all gasoline sold in the state to meet California Phase 2 Reformulated Gasoline standards. California refineries installed new equipment and modified existing equipment to produce gasoline that met the California RFG standards. According to the California Air Resource Board, the resulting statewide emissions reductions were substantial (69,350 tons/year for VOCs, 40,150 tons/year for NO_x, 10,950 tons/year for SO_2, 474,500 tons/year CO).[3] These emissions reductions dwarfed the emissions increases at refineries that occurred as a result of operation of the new and modified equipment. For example, at the Chevron Richmond Refinery, which is one of the largest refineries in California, offsets were needed for site-specific increases of 104 tons/year for VOCs (less than 0.2% of the statewide reductions); 151 tons/year for NO_x (less than 0.4% of the statewide reductions); 220 tons/year for SO_2 (2% of the statewide reductions); and 26 tons/year for CO (less than 0.01% of the statewide reductions).[4]

This discussion serves to illustrate the environmental tradeoffs that often accompany the implementation of new, environmentally beneficial technologies. The refinery emissions caps that would be imposed by the adoption of Regulation 12-16, however, would preclude the consideration of these tradeoffs and the implementation of such new technologies if the necessary improvements would result in increased emissions exceeding the caps, even if the impacts from such increased emissions would be substantially outweighed by environmental benefits offered by the new technologies.

In addition to the important policy implications associated with precluding this type of tradeoff, the effect of preventing future refinery improvement projects that could provide substantial environmental benefits is a potential, reasonably foreseeable adverse environmental effect of adopting Regulation 12-16. This effect should be included as part of a recirculated draft EIR.

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[3] See CARB Fact Sheet, which is available at the following internet address: https://www.arb.ca.gov/fuels/gasoline/pub/cbg_fs1.htm.

[4] See BAAQMD, Engineering Evaluation for Chevron's Reformulated Gasoline and FCC Modernization Project (Application 9978) (Apr. 25, 1994).

4. The Draft EIR Fails to Evaluate A Reasonable Range of Alternatives to Proposed Regulation 11-18

The fundamental purpose of conducting an alternatives analysis under CEQA is to identify feasible ways of accomplishing the proposed project while at the same time reducing the project's environmental impacts. Thus, in enacting CEQA, the Legislature declared that "it is the policy of the state that public agencies should not approve projects as proposed if there are feasible alternatives or feasible mitigation measures available which would substantially lessen the significant environmental effects of such projects." Pub. Res. Code § 21002. To that end, an EIR is required to evaluate a reasonable range of alternatives to the proposed project "which would feasibly attain most of the basic objectives of the project but would avoid or substantially lessen any of the significant effects of the project." CEQA Guidelines § 15126.6.

Here, the only alternatives to proposed Regulation 11-18 that are evaluated in the Draft EIR are the No Project Alternative and Alternative 1.2, which would establish risk action levels at 25 per million for cancer risk and 2.5 for the acute and chronic hazard indices, instead of the proposed action levels of 10 per million for cancer risk and 1.0 for the hazard indices. The Draft EIR concludes that Alternative 1.2 would reduce the significant and unavoidable air quality, GHG and water demand impacts from Regulation 11-18, but that the alternative would not achieve the project objectives to the same extent as the proposed regulation.

In evaluating only one action alternative, the Draft EIR does not evaluate a reasonable *range* of alternatives. Importantly, it has not been demonstrated that achieving the risk levels identified in the proposed regulation is technologically feasible at a facility such as a refinery. If these levels are not achievable at a particular facility, the regulation would require implementation of the best available retrofit control technology for toxic pollutants (TBARCT) on every significant source of toxic air contaminant emissions at the facility. But it has not been shown whether the emissions reductions from implementing TBARCT improvements at such a facility would substantially reduce health risks from hazardous air pollutants, while it has been shown in the Draft EIR that such improvements could result in significant and unavoidable impacts from emissions of criteria air pollutants. A range of alternatives that includes more than just Alternative 1.2 is particularly important under CEQA given the uncertainty over these issues.

For example, one alternative could be to adopt the risk thresholds of proposed Regulation 11-18 for smaller facilities where achieving such thresholds is more likely to be achievable without significant adverse consequences, while adopting the risk thresholds of Alternative 1.2 for larger facilities where the adverse effects of the proposed regulation may outweigh its benefits. Without an analysis of the reasonable spectrum of available regulatory approaches, it is not clear what the trade-offs are as between these different approaches, including a potential hybrid approach, with respect to both the environmental impacts that may be posed and the objectives that could be achieved. Such an analysis would help to ensure that these issues are carefully and thoroughly vetted before a final decision is made.

To provide an informative evaluation for policy makers and the public, the alternatives analysis for proposed Regulation 11-18 should be redone and presented in a recirculated draft EIR.

5. The Discussion of Alternatives Does Not Support a Decision to Adopt Proposed Regulation 12-16

The discussion of alternatives in the Draft EIR suffers from another significant problem. Specifically, it does not provide a proper basis under CEQA for approving Regulation 12-16.

The Draft EIR recognizes that the adoption of Rule 12-16 would lead to significant and unavoidable air quality impacts, significant and unavoidable water demand impacts, and significant hazard impacts requiring mitigation. As explained above, there are additional potentially significant impacts in terms of emissions of GHGs, criteria pollutants and toxic air contaminants that the Draft EIR has not yet disclosed. With respect to the impacts that have been identified, the Draft EIR concludes that Alternative 2.2 – which would consist of not adopting Regulation 12-16 and adopting Regulation 11-18 in combination with draft Regulation 13-1[5] instead – would eliminate or substantially reduce those impacts. (Draft EIR at pp. 4-13 to 4-15.) For this reason, the Draft EIR identifies Alternative 2.2 as the environmentally superior alternative. (*Id.* at p. 4-16.)

In addition, the Draft EIR explains that Alternative 2.2 "would achieve all the project objectives to a greater extent than the proposed project" of adopting Regulation 12-16. (Id. at p. 4-18.)

The Draft EIR's findings about Alternative 2.2 show that the Air District lacks a basis under CEQA for approving proposed Regulation 12-16. Where there are significant and unavoidable impacts from the proposed project and there is an alternative that would avoid or substantially lessen those impacts, the public agency may approve the proposed project only if there are specific economic, legal, social, technological or other considerations, supported by substantial evidence, that make the alternative infeasible. CEQA Guidelines § 15091(a)(3), (b). Here, the discussion in the Draft EIR indicates that the proposed project (adoption of Regulation 12-16) would result in significant and unavoidable impacts. It also shows that at least one alternative – Alternative 2.2 – would be capable of substantially lessening those impacts. And there is no evidence that such an alternative would be infeasible. Under these circumstances, CEQA's requirements preclude the approval of proposed Regulation 12-16.

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[5] Draft Rule 13-1 would set a carbon intensity limit for each refinery consistent with current operations (or set a mass-based GHG emissions limit as an alternative compliance option) and provide incentives for energy improvements.

6. Conclusion

To fulfill its role in promoting informed decision-making and meaningful public participation, the Draft EIR should be substantially revised, and the revised analysis should be presented in a recirculated draft for another round of public review and comment.

Sincerely yours,

Marc R. Bruner

cc: Shawn Lee, Manager, Health, Environment & Safety, Chevron Products Company
Amy Lincoln, Senior Counsel, Environmental & Safety Law Group, Chevron Corporation
Barbara Schussman, Perkins Coie

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May 8, 2017

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VIA EMAIL

Mr. Victor Douglas
Bay Area Air Quality Management District
375 Beale Street, Suite 600
San Francisco, CA 94105
vdouglas@baaqmd.gov

Re: Comments on Draft Environmental Impact Report (SCH #2016102043) For Proposed Air District Regulations 11-18 and 12-16

Dear Mr. Douglas:

We appreciate this opportunity to submit comments on behalf of Chevron U.S.A. Inc. on the Draft Environmental Impact Report prepared by the Bay Area Air Quality Management District addressing two proposed Air District regulations: Regulation 11-18, Toxic Risk Reduction Rule, and Regulation 12-16, Petroleum Refining Emissions Limits and Risk Thresholds.

Chevron appreciates the Air District's mission in protecting the air quality of the Bay Area and its residents. We also understand the concerns of the California Air Resources Board, the Air District, and the public about emissions of greenhouse gases and the effects of climate change. Further, we value our longstanding role as a member in this community.

It is in this context that we express our concerns that the Air District's current rulemaking proposals do not adequately recognize the environmental, economic and social trade-offs that are involved and the unintended negative consequences that the proposed regulations may have. For example, as recognized in the Staff Report prepared by Air District staff, the imposition of emissions caps at individual facilities may have broader impacts in terms of constraining the statewide market for transportation fuels, thereby leading to increased transport of fuels from other locations to meet demand. This unintended chain of events could actually increase GHG emissions statewide rather than reducing them, and also could increase emissions of criteria air pollutants and toxic air contaminants in California's bays and harbors due to increased shipments of fuels. Further, the imposition of emissions caps at individual facilities could prevent the future installation and operation of new technologies and equipment at those facilities, where these innovations could make fuels cleaner and thereby help to achieve substantial reductions in emissions from mobile sources across the state, but also could result in small emissions increases at the facilities that would be prohibited because of an inflexible regulatory cap. These trade-offs can be complex and difficult and we are concerned that the current regulatory proposals may be environmentally counter-productive in the long run. We would like to make sure that the big-picture environmental effects and trade-offs of the Air District's proposals are thoroughly and carefully vetted before a final decision is made that could trigger a chain of unfortunate and unintended consequences.

It is for these reasons that we share the concerns about Air District's proposed regulations that have been raised by the Western States Petroleum Association. One of the important concerns identified by WSPA is that the Air District has segmented its analysis under the California Environmental Quality Act of its proposed regulatory program as a whole for addressing refinery emissions, and that the Air District is dividing up its review of this overall program into smaller pieces, which has the effect of preventing a clear and comprehensive understanding of the adverse environmental consequences that the Air District's adoption of this program could cause.

In addition to this "piecemealing" problem, our review has identified several additional CEQA issues with the Draft EIR. In order to fulfill CEQA's goals of fostering informed decision-making and meaningful public participation, we respectfully maintain that the Air District should revise the environmental analysis in the Draft EIR and then recirculate the revised analysis in a new draft EIR for another round of public review and comment.

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- The environmental analysis should recognize and evaluate the potentially significant climate change and air quality effects that could result from the adoption of proposed Regulation 12-16. The March 2017 Staff Report touches on some of the problems that could arise if there is a constraint on the market for transportation fuels.

- The Draft EIR should explain more thoroughly how adoption of the proposed regulations could contribute to significant cumulative environmental impacts, including cumulative impacts on air quality and water supplies.

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In sum, the Draft EIR should be revised to provide a thorough and careful evaluation of the potential climate change and air quality effects that the emissions caps in Regulation 12-16 could cause by constraining the state's supply of transportation fuels. To provide a meaningful opportunity for public review, the revised analysis should then be presented in a recirculated draft EIR.

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>
> (5) A reasonable analysis of the cumulative impacts of the relevant projects.

Here, the short discussion of cumulative impacts in the Draft EIR does not reveal to the public and the decision-makers the serious consequences that could occur as a result of adopting the proposed regulations in conjunction with the effects of other past, present and reasonably foreseeable Air District regulations and control measures. For example, the introductory discussion of cumulative impacts states merely that the EIR "evaluates the cumulative environmental impacts associated with implementation of other air quality regulations as outlined in the 2017 Clean Air Plan." (Draft EIR, at p. 3.1-4.) The introduction to the discussion of cumulative air quality impacts similarly states that "related projects would consist of other past, present, and probable future BAAQMD rules and regulations, as well as implementing control measures in the 2017 Clean Air Plan." (Draft EIR at pp. 3.2-52 to 3.2-53.)

The Draft EIR then discusses the cumulative air quality impacts, but the discussion, which totals little more than one page of text, does not contain sufficient detail as to what the combined effects could be. There is no description of the related projects that bear on the air quality impacts of the two proposed regulations, no assessment of what the air quality impacts of these related projects are or could be, and no evaluation of how the effects associated with the two proposed regulations would interact or aggregate with the impacts from the related projects. (*Id.* at pp. 3.2-53 to 3.2-54.)

The discussion of cumulative water demand impacts similarly lacks meaningful content. This discussion, which totals two short paragraphs of text, simply reiterates the Draft EIR's prior conclusions regarding the project-specific impacts of the two proposed regulations, without any discussion of the specific items that are required under the CEQA Guidelines for an adequate evaluation of cumulative impacts. There is no reference to any of the related projects, let alone how the project-specific water demand impacts of the two proposed regulations, which are found to be significant and unavoidable, would interact or aggregate with the related projects' impacts on water usage and demand. (*Id.* at p. 3.5-23.)

In sum, the cumulative impact discussion in the Draft EIR should be revised to present a clearer picture of what the combined impacts could be from the proposed regulations together with other past, present and reasonably foreseeable future Air District rules and control measures. The revised analysis should then be presented in a recirculated draft EIR, so that there is a meaningful opportunity for public review.

3. The Draft EIR Fails to Evaluate the Negative Impacts that Proposed Regulation 12-16 Could Cause by Preventing Environmentally Beneficial Projects

One of California's climate change strategies, as embodied in the 2017 Climate Change Scoping Plan Update prepared by the California Air Resources Board, is the production of cleaner fuels to reduce GHG emissions from mobile sources. Mobile sources create nearly 50 percent of GHG emissions in the state, as well as 80 percent of emissions of oxides of nitrogen and 90 percent of particulate matter emissions. To produce cleaner fuels to advance the state's goals, new equipment likely will be needed at California refineries. Further, the operation of this new equipment likely will result in an increase in some stationary source emissions at the refineries. For example, such new equipment could cause some increases in GHG and other emissions at the refineries due to construction activities to install the equipment and the continued operation of the equipment as part of the refinery processes, while at the same time contributing to dramatic and important reductions in statewide emissions of GHGs from mobile sources.

California has in the past experienced a similar example of this phenomenon. In the mid-1990s, California state law required all gasoline sold in the state to meet California Phase 2 Reformulated Gasoline standards. California refineries installed new equipment and modified existing equipment to produce gasoline that met the California RFG standards. According to the California Air Resource Board, the resulting statewide emissions reductions were substantial (69,350 tons/year for VOCs, 40,150 tons/year for NO_x, 10,950 tons/year for SO_2, 474,500 tons/year CO).[3] These emissions reductions dwarfed the emissions increases at refineries that occurred as a result of operation of the new and modified equipment. For example, at the Chevron Richmond Refinery, which is one of the largest refineries in California, offsets were needed for site-specific increases of 104 tons/year for VOCs (less than 0.2% of the statewide reductions); 151 tons/year for NO_x (less than 0.4% of the statewide reductions); 220 tons/year for SO_2 (2% of the statewide reductions); and 26 tons/year for CO (less than 0.01% of the statewide reductions).[4]

This discussion serves to illustrate the environmental tradeoffs that often accompany the implementation of new, environmentally beneficial technologies. The refinery emissions caps that would be imposed by the adoption of Regulation 12-16, however, would preclude the consideration of these tradeoffs and the implementation of such new technologies if the necessary improvements would result in increased emissions exceeding the caps, even if the impacts from such increased emissions would be substantially outweighed by environmental benefits offered by the new technologies.

In addition to the important policy implications associated with precluding this type of tradeoff, the effect of preventing future refinery improvement projects that could provide substantial environmental benefits is a potential, reasonably foreseeable adverse environmental effect of adopting Regulation 12-16. This effect should be included as part of a recirculated draft EIR.

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[3] See CARB Fact Sheet, which is available at the following internet address: https://www.arb.ca.gov/fuels/gasoline/pub/cbg_fs1.htm.

[4] See BAAQMD, Engineering Evaluation for Chevron's Reformulated Gasoline and FCC Modernization Project (Application 9978) (Apr. 25, 1994).

4. The Draft EIR Fails to Evaluate A Reasonable Range of Alternatives to Proposed Regulation 11-18

The fundamental purpose of conducting an alternatives analysis under CEQA is to identify feasible ways of accomplishing the proposed project while at the same time reducing the project's environmental impacts. Thus, in enacting CEQA, the Legislature declared that "it is the policy of the state that public agencies should not approve projects as proposed if there are feasible alternatives or feasible mitigation measures available which would substantially lessen the significant environmental effects of such projects." Pub. Res. Code § 21002. To that end, an EIR is required to evaluate a reasonable range of alternatives to the proposed project "which would feasibly attain most of the basic objectives of the project but would avoid or substantially lessen any of the significant effects of the project." CEQA Guidelines § 15126.6.

Here, the only alternatives to proposed Regulation 11-18 that are evaluated in the Draft EIR are the No Project Alternative and Alternative 1.2, which would establish risk action levels at 25 per million for cancer risk and 2.5 for the acute and chronic hazard indices, instead of the proposed action levels of 10 per million for cancer risk and 1.0 for the hazard indices. The Draft EIR concludes that Alternative 1.2 would reduce the significant and unavoidable air quality, GHG and water demand impacts from Regulation 11-18, but that the alternative would not achieve the project objectives to the same extent as the proposed regulation.

In evaluating only one action alternative, the Draft EIR does not evaluate a reasonable *range* of alternatives. Importantly, it has not been demonstrated that achieving the risk levels identified in the proposed regulation is technologically feasible at a facility such as a refinery. If these levels are not achievable at a particular facility, the regulation would require implementation of the best available retrofit control technology for toxic pollutants (TBARCT) on every significant source of toxic air contaminant emissions at the facility. But it has not been shown whether the emissions reductions from implementing TBARCT improvements at such a facility would substantially reduce health risks from hazardous air pollutants, while it has been shown in the Draft EIR that such improvements could result in significant and unavoidable impacts from emissions of criteria air pollutants. A range of alternatives that includes more than just Alternative 1.2 is particularly important under CEQA given the uncertainty over these issues.

For example, one alternative could be to adopt the risk thresholds of proposed Regulation 11-18 for smaller facilities where achieving such thresholds is more likely to be achievable without significant adverse consequences, while adopting the risk thresholds of Alternative 1.2 for larger facilities where the adverse effects of the proposed regulation may outweigh its benefits. Without an analysis of the reasonable spectrum of available regulatory approaches, it is not clear what the trade-offs are as between these different approaches, including a potential hybrid approach, with respect to both the environmental impacts that may be posed and the objectives that could be achieved. Such an analysis would help to ensure that these issues are carefully and thoroughly vetted before a final decision is made.

To provide an informative evaluation for policy makers and the public, the alternatives analysis for proposed Regulation 11-18 should be redone and presented in a recirculated draft EIR.

5. The Discussion of Alternatives Does Not Support a Decision to Adopt Proposed Regulation 12-16

The discussion of alternatives in the Draft EIR suffers from another significant problem. Specifically, it does not provide a proper basis under CEQA for approving Regulation 12-16.

The Draft EIR recognizes that the adoption of Rule 12-16 would lead to significant and unavoidable air quality impacts, significant and unavoidable water demand impacts, and significant hazard impacts requiring mitigation. As explained above, there are additional potentially significant impacts in terms of emissions of GHGs, criteria pollutants and toxic air contaminants that the Draft EIR has not yet disclosed. With respect to the impacts that have been identified, the Draft EIR concludes that Alternative 2.2 – which would consist of not adopting Regulation 12-16 and adopting Regulation 11-18 in combination with draft Regulation 13-1[5] instead – would eliminate or substantially reduce those impacts. (Draft EIR at pp. 4-13 to 4-15.) For this reason, the Draft EIR identifies Alternative 2.2 as the environmentally superior alternative. (*Id.* at p. 4-16.)

In addition, the Draft EIR explains that Alternative 2.2 "would achieve all the project objectives to a greater extent than the proposed project" of adopting Regulation 12-16. (Id. at p. 4-18.)

The Draft EIR's findings about Alternative 2.2 show that the Air District lacks a basis under CEQA for approving proposed Regulation 12-16. Where there are significant and unavoidable impacts from the proposed project and there is an alternative that would avoid or substantially lessen those impacts, the public agency may approve the proposed project only if there are specific economic, legal, social, technological or other considerations, supported by substantial evidence, that make the alternative infeasible. CEQA Guidelines § 15091(a)(3), (b). Here, the discussion in the Draft EIR indicates that the proposed project (adoption of Regulation 12-16) would result in significant and unavoidable impacts. It also shows that at least one alternative – Alternative 2.2 – would be capable of substantially lessening those impacts. And there is no evidence that such an alternative would be infeasible. Under these circumstances, CEQA's requirements preclude the approval of proposed Regulation 12-16.

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[5] Draft Rule 13-1 would set a carbon intensity limit for each refinery consistent with current operations (or set a mass-based GHG emissions limit as an alternative compliance option) and provide incentives for energy improvements.

6. Conclusion

To fulfill its role in promoting informed decision-making and meaningful public participation, the Draft EIR should be substantially revised, and the revised analysis should be presented in a recirculated draft for another round of public review and comment.

Sincerely yours,

Marc R. Bruner

cc: Shawn Lee, Manager, Health, Environment & Safety, Chevron Products Company
Amy Lincoln, Senior Counsel, Environmental & Safety Law Group, Chevron Corporation
Barbara Schussman, Perkins Coie

From: David <davidk5160@icloud.com>
Sent: Sunday, May 7, 2017 10:29 PM
To: Victor Douglas
Subject: Comments on Draft EIR: Regulation 11-18 & 12-16

Dear Mr. Douglas,

I am a City of Pittsburg resident and work for the Chevron Refinery in Richmond, Ca. I have concerns with some of the items in the Draft Environmental Impact Report on Regulation 11-18 and 12-16 (dated March 2017) and have the following comments I would like to make on the draft EIR:

- Table 3.2-2 - Bay Area Air Pollution Summary - 2015
    - COMMENT: Why is most of the data for Richmond and Martinez left out of this table? There are two refineries in Martinez and one in Richmond. Since these rules directly affect refineries in these two cities I would expect to see more air quality data.
- Section 1.4.2.2 Page 1-10 "For example, it is impossible for the Air District to predict the exact level of gasoline consumption in 2018 and how that would relate to Bay Area refinery capacity and how the market might react if production at Bay Area refineries were constrained by Rule 12-16. Therefore, the Air District is assuming, based on historical data that potential GHG emission impacts from the proposed project are concluded to be less than significant."

    - COMMENT: Why were the affects of AB-32 on refineries excluded from the EIR? They currently affect refineries and should be included. Market researchers and analysts have the ability to forecast gasoline demand.

Regards,

David Kubeck
Pittsburg, CA Resident

Bay Area Air Quality Management District
375 Beale Street, Suite 600
San Francisco CA 94105

VIA EMAIL
vdouglas@baaqmd.gov
Victor Douglas

May 8, 2017

Re: Health impacts and implications should be included in the No Project and alternative scenarios and the environmental and regulatory settings sections of the EIR for BAAQMD Rule 12-16

We are writing to encourage the Air District to include a comprehensive health and safety assessment in the final EIR of Rule 12-16, as detailed in the following submission. In particular, by providing a preliminary assessment of potential mortality impacts in the absence of Rule 12-16's preventive measures, this submission demonstrates the feasibility and importance of including a health assessment in the EIR. It is important that such an assessment account for:

- the preventive nature of Rule 12-16
- the influx of heavier crude oil feedstock that is projected in the absence of emissions caps
- resulting exposures and impacts on vulnerable populations, including people who live in proximity to the refineries, have low socio economic standing and / or disadvantaged racial identity, are infants, young children or the elderly, live in already polluted settings, and/or have underlying health conditions

Respectfully
Signatures, listed alphabetically on the following page,

David Bezanson PhD	Clinical psychologist, retired
Claire V Broome MD	Adjunct Professor, Rollins School of Public Health Emory University Assistant Surgeon General, US Public Health Service (retired)
Wendel Brunner MD, PhD, MPH	Former Director of Public Health, Contra Costa Health Services
Robert M. Gould, MD	President, Physicians for Social Responsibility, San Francisco Bay Area Chapter Associate Adjunct Professor, Program on Reproductive Health and the Environment, Dept. of Obstetrics, Gynecology & Reproductive Sciences UCSF School of Medicine (for identification purposes only)
Jonathan Heller PhD	Co-Director and Co-Founder, Human Impact Partners Oakland CA
Richard J Jackson MD MPH	Former California State Public Health Officer Director, CDC National Center for Environmental Health (retired)
Janice L Kirsch MD MPH	Medical oncologist and hematologist
Chaz Langelier MD, PhD	Postdoctoral Scholar Center for AIDS Research University of California, San Francisco (for identification purposes only)
Raymond Neutra MD DrPH	Chief Division of Environmental and Occupational Disease Control, California Department of Public Health (retired)
Thomas B Newman MD MPH	Professor Emeritus of Epidemiology & Biostatistics and Pediatrics, University of California, San Francisco (for identification purposes only)
Bart Ostro PHD	Former Chief of Air Pollution Epidemiology Section, California EPA, currently Research Faculty, Air Quality Research Center, UC Davis
Linda Rudolph MD MPH	Director, Center for Climate Change and Health, Public Health Institute Oakland, CA
Seth BC Shonkoff PhD, MPH	Executive Director | PSE Healthy Energy Visiting Scholar | Dept. Environmental Science, Policy, & Management, UCB Affiliate | Energy Technologies Area, Lawrence Berkeley National Lab
Patrice Sutton, MPH	Research Scientist, Program on Reproductive Health and the Environment, University of California, San Francisco (for identification purposes only)

Coordinated by

Heather Kuiper DrPH MPH	Public Health Consultant, Oakland CA

May 8, 2012

To the Bay Area Air Quality Management District Board:

This submission alerts the Air District that the Rule 12-16 draft EIR does not adequately analyze or discuss the health impacts that were identified in a letter submitted December 2, 2016 during the Notice of Preparation and Initial Study for the Rule 12-16 DEIR. In particular, the draft EIR does not adequately recognize the preventive nature of Rule 12-16, thus omitting health implications from the "No Project" alternative.

Preventing increases in harmful exposures is a well-established health protection measure. (Curie 2011, Pope 2009, Goodman 2002, Hedley 2002, Dominici 2006). A preventive approach to air quality is important, due to an otherwise anticipated increase in Bay Area refineries' use of heavier, dirtier oil feedstock, [1] (BAAQMD 2012a) which will lead to higher exposures to fine particulate matter (PM2.5). PM2.5 is definitively established as a cause of adverse health impacts, including mortality. Given the dense population of the Bay Area, increased PM2.5 will have large population impacts, presenting a major public health threat. Rule 12-16 is an important public health tool as it caps refinery emissions at current levels, thereby preventing increases in exposure to PM2.5.

Omission of the No Project Alternative (not implementing Rule 12-16) and its health impact

Because Rule 12-16 is a preventive measure, the Air District can anticipate that the "No Project" scenario will increase mortality in the Bay Area population, especially among the disadvantaged. The assessment,[2] detailed in Appendix A, measures the impact of long-term exposure to increased PM2.5 resulting from transitions to heavier oil feedstock. Adjusting for other exposures, it finds that:

- **Rule 12-16 could cumulatively prevent 800 to 3000 deaths of Bay Area residents given a refinery facility lifetime of 40 years following conversion to heavier crude**
- **The additional mortality burden for the Bay Area's disadvantaged residents could be 8 – 12 times that of the Bay Area's general population**
- **Annual monetary valuation of these deaths alone could reach up to $123.2 million, or cumulatively, up to $4.84 billion dollars. (CAP, 2017 p C/7)**

This assessment is conservative in its parameters and many of the model parameters are drawn from BAAQMD's own work. For example, it does not consider indoor air exposures, which may be higher, (Brody, 2009), impacts of ultrafine particulates (Ostro, 2015), or increased combustion, production, and handling of pet coke (US EPA). The submitted analysis is also conservative in scope: It does not include PM2.5-related morbidity, neurological, cognitive, and developmental impairment, (especially of children), hospitalizations, lost productivity, reduced activity, and health-related socio-economic impacts. Significantly, the analysis does not include health impacts associated with flares and other acute PM2.5 exposures, including mortality, cardiac events, hospitalizations, and increased susceptibility to adverse health conditions from the underlying stressors of living in proximity to pollution sources (DeFur 2007, Cutchin 2008, Luginaah 202). It also does not include the significant local climate-related

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[1] This assessment is predicated on a finding that, without 12-16, Bay Area refineries will likely undergo large-scale capital conversions for refining heavier crude oils and natural bitumen (including and especially tar sands crude), resulting in increased PM2.5 emissions and toxicity, and increased greenhouse gas emissions. (BAAQMD 2012a, Karras, 2016)

[2] This assessment draws from calculations of emissions increases attributable to heavier crude oil feedstock produced by Greg Karras of Communities for a Better Environment (Karras, 2016) It was conducted in collaboration with CBE.

health hazards and impacts that will be attributable to the Bay Area's increased refining of heavier crude feedstock.

Even so, this analysis demonstrates that is reasonable and feasible for the District to develop and consider health impact projections in its final EIR. The signatories request that the Air District include the attached assessment (Appendix A) in its final EIR and also supplement it with estimates of additional health impacts attributable to increased PM2.5 and greenhouse gas emissions, especially for vulnerable populations. See also Appendices B, and C for information that can support such additional analysis.

Modify the draft EIR's assessment of alternatives

Emission intensity caps (Rule 13-1) and mass emission caps (Rule 12-16) are complementary measures and their combination could protect health better than Rule 12-16 alone. This alternative is not considered in the draft EIR although Rule 13-1 is discussed in combination with Rule 11-18. CEQA requires an alternative to accomplish the main objectives of the project at hand, yet Rules 13-1 and 11-18 do not provide health protection equivalent to 12-16. Rule 11-18 targets various toxic air contaminants but not greenhouse gases and particulate matter and is fundamentally different in terms of health protection strategy and outcome. Rule 13-1, *as currently drafted*, omits direct control of PM2.5 and could allow facility-wide refinery emissions to increase; it is does not provide protections comparable to Rule 12-16. Regardless, it is premature to consider Rule 13-1 in the Rule 12-16 EIR.

Expand the existing environmental and regulatory settings assessments

The following considerations should be included in the environmental settings assessment:

- Cities in the San Francisco Bay Area are among the most polluted in the U.S. (ALA, 2017) High baseline air pollution augments susceptibility to adverse health threats. Due to this baseline condition, Bay Area residents will likely experience augmented health risk and burden from increased emissions. Further, the Air District, Cal EPA, the US EPA and the World Health Organization, all find that, "people exposed to PM at levels below the current EPA standards may still experience negative health effects." (BAAQMD, 2012 p 17). There are no safe levels of particulate matter, and given high baseline pollution, every PM2.5 exposure increment will contribute to increased risk of mortality, morbidity, and lost productivity for Bay Area residents.

- This high baseline pollution is not uniformly or fairly distributed, "PM concentrations – and population exposure to PM – can vary significantly at the local scale… People who live or work near major roadways, ports, distribution centers, or other major emission sources… may be disproportionately exposed to certain types of PM (e.g. ultrafine particles)…" (BAAQMD, 2012, p 14) There is growing evidence that proximity to oil refineries places residents at disproportionate risk for adverse health outcomes. Appendix C provides a partial list of this evidence base. There is also documentation that residents in proximity to refineries are disproportionately vulnerable by virtue of race, economic standing, and higher prevalence of underlying health conditions (Cushing 2016, Pastor 2010). The final EIR should recognize as part of the current landscape that failure to prevent increased refinery emissions will have environmental justice repercussions since they will predominantly occur in communities where residents are low income and/or are people of color and already disproportionately burdened by poor underlying health and multiple-source pollution exposures.

- The draft EIR should recognize that state and local policy specifically precludes placing disproportionate burden on impacted, disadvantaged populations. Senate Bill 32 and Assembly

Bill 197 recognize and protect these populations by requiring consideration of equity and social costs in reducing greenhouse gases and equitable resolution of them, prioritizing direct emissions reductions at large stationary sources. CEQA and the District's own mission also affirm a health mandate. Protecting public health and eliminating health disparities are stated goals of the 2017 Clean Air Plan. Rule 12-16 should be understood in light of this state-level policy framework for environmental health protection and the District's own mission.

- Current conditions with regards to Bay Area emissions are not static. Instead, the setting for Rule 12-16 is trending toward increases in the processing of heavier, higher-emitting, lower quality crude oils, expansion of projects to do so, and expanding fossil fuel export. (BAAQMD, 2013) Switching to heavier crudes will inherently increase emissions of PM2.5 and greenhouse gases, making it imperative that measures be put in place to prevent these future increases in emissions, *in addition to* measures decreasing current emissions. Without the preventive caps offered by Rule 12-16, other District measures will be limited by a context of rising emissions.

- The corresponding increase in fossil fuel exports will lead to an increase in exogenous air pollution in the Bay Area since a portion of the byproducts of combustion of fossil fuels exported from the Bay Area will return to us from Asia through transpacific atmospheric transport. This exogenous air pollution will directly threaten health and also impede progress toward the targets and goals of the Clean Air Plan, 2017. Exogenous / overseas sources of pollution are of increasing concern as they have been directly implicated in deaths in local populations and documented as a greater proportion of exposure than locally-sourced pollution in some settings. (Annenberg 2014, Christensen 2015, Zhang 2007, 2008, 2009).

Lastly, the health comments submitted to the District in December 2016 were omitted from Appendix A of the draft EIR and we ask that they be included.

The signatories believe these adjustments are necessary for the EIR to be complete and accurate and respectfully request they be made in time for Rule 12-16's potential adoption in September.

APPENDIX A:

Impact of Rule 12-16 on mortality associated with exposure to PM2.5 from processing heavier oil in Bay Area refineries

Table 1 Potential health impact of 12-16: Averted all-cause deaths attributable to chronic exposures to oil refinery PM2.5 (see Appendix for calculations)

	Regional Population (9 Bay Area Counties)			**Impacted Population*** (<=2.5 miles from refinery)		
	Low	Med	High	Low	Med	High
PARAMETERS						
Risk						
a. Risk of all-cause death for adults (>30 yrs) per 1$\mu g/m^3$ PM2.5 increase in long-term exposure	1.008	1.01	1.012	1.008	1.01	1.012
b. Incremental Risk: risk of all-cause death for adults attributable to increment in long-term PM2.5 exposure (risk/ per 1$\mu g/m^3$ PM2.5 increase)	*0.008*	*0.01*	*0.012*	*0.008*	*0.01*	*0.012*
Exposure						
c. Baseline anthropogenic** exposure ($\mu g/m^3$ $PM_{2.5}$)		5.7			5.1	
d. Proportion of baseline anthropogenic exposure attributable to baseline refinery activity		.05			0.5	
e. Percent change from baseline anthropogenic emissions due to higher emitting oil emissions	40%	70%	100%	40%	70%	100%
f. Conversion factor (change in PM2.5 exposure per change in PM2.5 emissions)		0.5		0.4	0.5	0.6
g. Averted exposure: the annual increased PM2.5 concentration attributed to heavier oil that is averted by Rule 12-16 ($\mu g/m^3$ $PM_{2.5}$)	*0.057*	*0.10*	*0.143*	*0.408*	*0.893*	*1.53*
Population and Mortality						
h. Adult Population (>25)		5,144,345			81,666	
i. Base all-cause adult death rate / person / year		*0.0083403*			*0.0091899*	
IMPACT						
j. Prevented adult all-cause deaths due to 12-16 averting increases in heavier oil PM2.5 emissions* **	**20**	**43**	**73**	**2**	**7**	**14**
k. Rate of prevented adult all-cause death due to 12-16 averting increases in heavier oil PM2.5 emissions /100,000 population /yr	**0.38**	**0.83**	**1.43**	**3.00**	**8.21**	**16.88**
l. Cumulative prevented deaths due to 12-16 (40 yrs)	**800**	**1700**	**2900**	**98**	**270**	**550**

* The distance of 2.5 miles was selected to correspond with findings from Brody (2009) and Pastor (2010). Those living < 2.5 miles of refineries (Table 5) can roughly be interpreted as a proxy for impacted, vulnerable, and/or Environmental Justice populations. The Air District's CARE program prioritizes communities and populations most impacted by air pollution, i.e., those with higher air pollution levels and worse health outcomes for diseases affected by air pollutions. Vulnerable populations also include those with heightened vulnerability to PM due to age (<5, elderly), low SES, minority race/ethnic status, and underlying health conditions. This proxy is conservative because *disparate impacts on vulnerable populations may occur beyond 2.5 miles.*

** Anthropogenic exposure is the ambient PM2.5 concentration above background levels (e.g., from sea salt).

*** Annual and cumulative deaths are presented as whole numbers. The resulting rounding error explains any discrepancy between presented deaths and rate.

Notes for Table 1

a. For every 1µg/m3 PM2.5 increase in exposure there is x% increased risk of all-cause mortality, e.g., a 1% increased risk of all-cause death per 1µg/m3 PM2.5 exposure increase. Risk estimates are from BAAQMD's literature review, of for example Pope et. al (2002), Krewsk et. al, (2000), and others. Risk may be underestimated as it does not account for 1) greater energy intensity and toxicity of PM2.5 associated with heavy oil and natural refining, 2) ultrafine PM, and 3) greater vulnerability of impacted populations.

b. Calculated as (all cause death risk in exposed) – (all cause death risk in unexposed), i.e, (risk per increase of 1µg/m^3 PM2.5) – (no increase in exposure) = 1.01 – 1 = .01. For every exposure change of 1µg/m^3 PM2.5 there is a corresponding 1% change in all-cause mortality attributable to PM2.5

c. _Regional_: CAP 2017 p C/7

Impacted Population (<2/5 miles from refinery): From Brody et. al.(2009) baseline PM2.5 exposure was directly measured in Richmond at distances approximately 2.5 miles from the dominant $PM_{2.5}$ source in the refinery. To isolate exposure above background, control site measures in Bolinas were subtracted from Richmond measures, yielding µg/m3 PM2.5. The PM2.5 was chemically fingerprinted to the refinery, finding, for example, high levels, of vanadium and nickel, which in this setting are isolated to refinery emissions (versus traffic). Validating this measure, CARB "ADAM" data for 2013 subtracts annual mean PM2.5 measures at Pt. Reyes from measures at the monitoring station nearest to the refinery, yielding 5.04 µg/m3 PM2.5. A baseline exposure of 4.5 µg/m3 PM2.5 likely underestimates annual exposure because 1) the Brody study was conducted during the summer when PM2.5 concentrations are lowest and 2) Due to wind patterns, and refinery distribution, populations near the other refineries may experience a concentrating of PM2.5. For these reasons, a conservative adjustment was made to factor in higher wintertime concentrations. The annual median concentration was divided by the median concentration Apr–Sep for three years of monitoring at the three closes sites (San Pablo, Vallejo, Concord). The mean of the resulting ratios was multiplied by the Brody measure (2009) such that 4.5 x 1.13 = 5.1 µg/m3 PM2.5 anthropogenic [ ].

d. Portion of the baseline anthropogenic exposure that is attributable to baseline refinery activity
Regional: CAP, 2017 p 2/20
Impacted Population: We set the portion at .5 since Brody et. al. (2009) used chemical fingerprinting to find that heavy oil combustion (refineries being the predominant source in the study area) is the most important contributor, more important than traffic, to elevated anthropogenic PM2.5 concentrations in the study area (<2.5 miles from refinery). We consider this measure reasonable in light of 1) BAAQMD grid modeling that ranged from .2 - .6, 2) an independent assessment of the Districts aerial emissions intensity data (2015) found that, on a mass/$mile^2$ basis, within 2.5 miles of the refineries, the areal source strength is more than twice (0.7) the regional average for all sources (CBE, 2015), and 3) accommodation of some lofting of emissions from hot stacks (2017 Staff Report). These parameters nevertheless likely underestimate, since downwind refinery communities could experience consolidation of PM2.5 from multiple refineries. Further, statewide analyses link high exposure to refinery proximity (<2.5 miles) (Pastor et. al. 2010).

e. Karras (2016) estimated a range of annual tons of PM2.5 emissions that Rule 12-16 would avert, such that, meaning that annually, Rule 12-16 would prevent increases of 364, 728, or 1090 short tons PM2.5 / yr of heavier oil-associated emission, or 40%, 70%, and 100% from current refinery emission rates could be averted through Rule 12-16. Medium Case (0.7) is the midpoint of the 0.4 - 1.0 range

f. The conversion factor translates emissions into exposure. It is derived from the regional weighted average change in PM$_{2.5}$ exposure for a given change in direct emissions of PM$_{2.5}$. Verified by measurements and assuming a 24 hour “backyard exposure,” BAAQMD modeled PM2.5 exposure change on a region-wide 4x4km grid relative to a 20% reduction in all-source PM2.5 emissions finding a range from .2 - .6. (CAP, 2017 D/13),
Regional: We applied .5 as the central measure to recognize that the location of population, emission sources, and meteorological conditions coincide. BAAQMD also applied approximately .5 for their regional average conversion. The conversion factor may underestimate impacted population exposures since refineries are strong PM2.5 emission sources near densely populated communities.
Impacted Population: For the <2.5 miles group, given population density and proximity to refineries, which are strong emitters, we used .4 for the lower bound. The upper bound, .6, may underestimate exposure for this group, given monitoring station locations.

g. The increased concentration of PM2.5 (exposure) attributed to heavier oil refining that is averted by Rule 12-16 (μg/m^3 PM$_{2.5}$). Calculated as (baseline total anthropogenic exposure) x (portion of baseline anthropogenic exposure attributable to baseline refinery emissions) x (Portion change from baseline anthropogenic emissions due to higher emitting oil emissions that is averted by 12-16) x (conversion factor). For the Medium regional case: 5.7 μg/m3 PM2.5 x .05 x .7 x .5 = *0.10* μg/m3 PM2.5. The attributable exposure may be underestimated because it does not account for: 1). NOx and SO2 PM-precursor emissions, and 2) the greater concentration of toxics associated with refining of heavy crude feedstock.

h. See Tables 2 and 3

i. Calculated as (annual deaths / total population) / yr. May overestimate or underestimate death rate over time should risk factors systematically improve or worsen.

j. Prevented deaths calculated as Attributable Risk x Attributable Exposure x all-cause per cap death rate x population. For middle regional scenario: .01 x .1 x .00589 x 7,447,686 = 44 deaths prevented by Rule 12-16.

k. Calculated as (deaths prevented / population) x 100,000 population / year.

l. Cumulative Impact calculated as deaths prevented x 40 years, since capital projects to accommodate heavier crude feedstock generally operate for 30 - 50 years. This number underestimates cumulative impact if population increases, as is anticipated.

Table 2. Bay Area communities ≤ 2.5 miles from refineries; local-scale population data [a]

Census	Refinery [b]	Tract distance to fence line (miles)		Fraction [c]	Population	
Tract	≤ 2.5 miles	closest	furthest	≤ 2.5 miles	Total	≤ 2.5 miles
3650.02	Chevron	0.5	2.5	1.00	5,462	5,462
3660.02	Chevron	2.3	3.3	0.20	6,093	1,219
3680.01	Chevron	1.5	2.5	1.00	5,327	5,327
3680.02	Chevron	2.0	2.7	0.71	3,404	2,431
3720	Chevron	1.8	3.1	0.54	7,353	3,959
3740	Chevron	2.0	2.8	0.63	4,506	2,816
3750	Chevron	1.3	1.8	1.00	4,389	4,389
3760	Chevron	0.4	1.5	1.00	5,962	5,962
3770	Chevron	0.4	2.4	1.00	6,962	6,962
3780	Chevron	0.0	3.1	0.81	3,435	2,770
3790	Chevron	1.1	3.1	0.70	6,117	4,282
2506.04	Phillips 66	2.1	3.7	0.25	3,842	961
3560.01	Phillips 66	0.0	3.5	0.71	3,759	2,685
3570	Phillips 66	1.0	5.5	0.33	3,018	1,006
3580	Phillips 66	0.0	2.0	1.00	5,298	5,298
3591.04	Phillips 66	2.0	3.0	0.50	1,932	966
3591.05	Phillips 66	2.0	3.0	0.50	4,542	2,271
3592.03	Phillips 66	1.0	3.3	0.65	6,726	4,387
3923	Phillips 66	1.0	2.0	1.00	3,102	3,102
3150	Shell &/or Tesoro	0.0	7.0	0.36	3,281	1,172
3160	Shell &/or Tesoro	0.5	2.0	1.00	1,483	1,483
3170	Shell &/or Tesoro	0.1	1.0	1.00	2,144	2,144
3180	Shell &/or Tesoro	0.7	4.7	0.45	3,267	1,470
3190	Shell &/or Tesoro	0.2	2.0	1.00	7,412	7,412
3200.01	Shell &/or Tesoro	0.0	2.0	1.00	3,615	3,615
3200.03	Shell &/or Tesoro	0.7	1.6	1.00	2,805	2,805
3200.04	Shell &/or Tesoro	0.2	2.0	1.00	6,216	6,216
3211.01	Shell &/or Tesoro	1.4	2.5	1.00	6,549	6,549
3270	Shell &/or Tesoro	2.0	6.0	0.13	6,695	837
3290	Shell &/or Tesoro	2.0	3.6	0.31	6,309	1,972
2520	Valero	1.8	3.5	0.41	4,157	1,712
2521.02	Valero	0.0	6.0	0.42	3,874	1,614
2521.04	Valero	0.0	4.0	0.63	5,536	3,460
2521.05	Valero	1.7	3.0	0.62	3,256	2,004
2521.06	Valero	0.5	2.0	1.00	4,132	4,132
2521.07	Valero	0.0	1.5	1.00	3,592	3,592
2521.08	Valero	1.0	2.0	1.00	3,165	3,165
		Sum of these tract data:			**168,717**	**121,608**

a) 2010 Census: https://factfinder.census.gov/faces/tableservices/jsf/pages/productview.xhtml?fpt=table

b) Plant or plants within 2.5 miles of part or all of the census tract, identified by current owner/operator.

c)) Estimation of population for tracts partly within a 2.5-mile radius: Tract fraction ≤ 2.5 miles = (2.5 - distance of bisection with radius in miles) ÷ (furthest distance – bisection distance in miles). Results are used to estimate the fraction of the total tract population ≤ 2.5 miles from a refinery. This method's simplifying assumption that population is distributed evenly within each tract despite geography and distance from refineries may result in overestimates or underestimates of local-scale population for those tracts that are partly within 2.5 miles of a refinery.

Table 3. Demographic and Vital Statistics for Bay Area Counties, 2013

		Age Group (years)										
Counties	<1	1-4	5-14	15-24	25-34	35-44	45-54	55-64	65-74	75-84	85+	TOTAL
Alameda												
Deaths	88	10	21	117	160	260	647	1,270	1,604	2,041	3,376	9,597
Population	19,493	76,842	190,900	203,954	232,027	231,327	222,525	191,268	111,600	55,333	28,101	1,563,370
Death Rate*	451.4	13.0	11.0	57.4	69.0	112.4	290.8	664.0	1437.3	3688.6	12013.8	613.9
Contra Costa												
Deaths	50	8	9	77	110	162	439	835	1,235	1,647	2,576	7,148
Population	12,240	49,755	146,153	145,402	129,256	143,616	163,677	140,700	86,747	42,739	21,577	1,081,862
Death Rate	408.5	16.1	6.2	53.0	85.1	112.8	268.2	593.5	1423.7	3853.6	11938.6	660.7
Marin												
Deaths	13	3	3	15	16	32	96	169	269	422	849	1,887
Population	2,334	9,858	30,334	26,078	23,766	32,876	41,089	40,325	28,899	13,245	7,460	256,264
Death Rate	557.0	30.4	9.9	57.5	67.3	97.3	233.6	419.1	930.8	3186.1	11380.7	736.4
Napa												
Deaths	6	1	1	9	10	23	51	125	188	269	511	1,194
Population	1,412	6,196	17,164	19,139	17,225	17,305	19,546	18,767	12,674	6,715	3,688	139,831
Death Rate	424.9	16.1	5.8	47.0	58.1	132.9	260.9	666.1	1483.4	4006.0	13855.7	853.9
San Francisco												
Deaths	30	4	6	40	91	172	351	749	809	1,268	2,134	5,655
Population	9,034	32,463	58,301	78,811	172,506	144,989	112,817	102,892	63,511	38,509	19,994	833,827
Death Rate	332.1	12.3	10.3	50.8	52.8	118.6	311.1	727.9	1273.8	3292.7	10673.2	678.2
San Mateo												
Deaths	19	2	5	35	52	94	257	477	673	1,102	1,920	4,636
Population	9,031	36,415	90,434	83,106	96,589	107,539	110,625	97,585	60,491	32,391	17,651	741,857
Death Rate	210.4	5.5	5.5	42.1	53.8	87.4	232.3	488.8	1112.6	3402.2	10877.6	624.9
Santa Clara												
Deaths	83	12	16	99	117	232	571	1,041	1,388	2,314	3,584	9,457
Population	24,112	95,493	245,789	228,340	264,949	282,446	270,707	211,136	126,347	68,609	32,667	1,850,595
Death Rate	344.2	12.6	6.5	43.4	44.2	82.1	210.9	493.0	1098.6	3372.7	10971.3	511.0
Solano												
Deaths	29	5	7	48	68	93	187	442	520	722	851	2,972
Population	5,127	20,641	55,419	59,872	56,830	53,419	61,449	56,360	32,286	15,914	6,731	424,048
Death Rate	565.6	24.2	12.6	80.2	119.7	174.1	304.3	784.2	1610.6	4536.9	12643.0	700.9
Sonoma												
Deaths	17	5	7	30	47	67	215	519	626	893	1,606	4,032
Population	5,070	21,413	58,627	65,627	64,121	59,350	69,251	71,808	45,050	20,879	11,874	493,070
Death Rate	335.3	23.4	11.9	45.7	73.3	112.9	310.5	722.8	1389.6	4277.0	13525.3	817.7
Bay Area												
Deaths	335	50	75	470	671	1135	2814	5627	7312	10678	17407	46578
Population	87853	349076	893121	910329	1057269	1072867	1071686	930841	567605	294334	149743	7384724
Death Rate	381.3	14.3	8.4	51.6	63.5	105.8	262.6	604.5	1288.2	3627.9	11624.6	630.7
<2.5 miles from refinery**												
Deaths	6	1	1	10	14	21	51	103	142	191	277	817
Population	1,402	5,685	16,278	16,577	15,027	15,911	18,180	15,913	9,612	4,736	2,286	121,608
Death Rate	454.9	18.5	7.9	60.9	95.7	129.4	278.1	648.0	1474.4	4039.0	12106.1	672.0

	Regional			<2.5miles		
	Death	Pop	Rt.	Death	Pop	Rt.
Adults >25 yr***	42905	5,144,345	834.03	751	81,666	918.992

*Death rates are age-specific expressed per 100,000 population. Age-adjusted rates are calculated using the 2000 U.S. Standard Population.

** Deaths in the Impacted Population (<2.5 miles from refinery) were derived using a death rate that divided Contra Costa and Solano Counties' combined deaths by their combined populations and applying this rate to the population living within 2.5 miles of a refinery for one year (from Table 2) (9,521 ÷ 1,518,002) x 121,608 = 763. This estimate may underestimate refinery effects on impacted populations because baseline death rates in communities near refineries may be greater than county-wide average rates. The age specific populations and deaths for the <2.5 miles group were arrived at by multiplying the total population by the age-specific death and population distribution of the combined Contra Costa and Solano Counties .

***The total adult deaths were adjusted to remove suicides and accidents by multiplying the unadjusted total by 6%, which represented the average and most frequent percent of deaths by suicide/accident for each county.

Population ≤ 2.5 miles from refinery fence lines estimated from census tract data. See Table 2
Source: State of California, Department of Public Health, Death Records. State of California, Department of Finance, Race/Ethnic Population with Age and Sex Detail, 2010-2060. Sacramento, CA, December 2014
State of California, Department of Finance, Race/Ethnic Population with Age and Sex Detail, 2010-2060. Sacramento, CA, December 2014.

APPENDIX B

Summary of pollutant – health outcome pairs to inform fuller health assessment of the No-Project Alternative

Table 1 Pollutant–health outcome pairs for which HRAPIE project recommends concentration–response functions (modified from WHO 2013b)

Pollutant metric	Health outcome	Group	RR (95 % CI) per 10 $\mu g/m^3$
$PM_{2.5}$, annual mean	Mortality, all-cause (natural), age 30+ years	A*	1.062 (1.040–1.083)
$PM_{2.5}$, annual mean	Mortality, cerebrovascular disease (includes stroke), ischaemic heart disease, COPD and trachea, bronchus and lung cancer, age 30+ years	A	GBD 2010 study (IHME 2013)[a]
PM_{10}, annual mean	Postneonatal (age 1–12 months) infant mortality, all-cause	B*	1.04 (1.02, 1.07)
PM_{10}, annual mean	Prevalence of bronchitis in children, age 6–12 (or 6–18) years	B*	1.08 (0.98–1.19)
PM_{10}, annual mean	Incidence of chronic bronchitis in adults (age 18+ years)	B*	1.117 (1.040–1.189)
$PM_{2.5}$, daily mean	Mortality, all-cause, all ages	A	1.0123 (1.0045–1.0201)
$PM_{2.5}$, daily mean	Hospital admissions, CVDs (including stroke), all ages	A*	1.0091 (1.0017–1.0166)
$PM_{2.5}$, daily mean	Hospital admissions, respiratory diseases, all ages	A*	1.0190 (0.9982–1.0402)
$PM_{2.5}$, 2-week average, converted to $PM_{2.5}$, annual average	RADs, all ages	B**	1.047 (1.042–1.053)
$PM_{2.5}$, 2-week average, converted to $PM_{2.5}$, annual average	Work days lost, working-age population (age 20–65 years)	B*	1.046 (1.039–1.053)
PM_{10}, daily mean	Incidence of asthma symptoms in asthmatic children aged 5–19 years	B*	1.028 (1.006–1.051)
O_3, summer months (April–September), average of daily maximum 8-h mean over 35 ppb	Mortality, respiratory diseases, age 30+ years	B	1.014 (1.005–1.024)
O_3, daily maximum 8-h mean over 35 ppb	Mortality, all (natural) causes, all ages	A*	1.0029 (1.0014–1.0043)
O_3, daily maximum 8-h mean over 10 ppb	Mortality, all (natural) causes, all ages	A	1.0029 (1.0014–1.0043)
O_3, daily maximum 8-h mean over 35 ppb	Mortality, CVDs and respiratory diseases, all ages	A	CVD: 1.0049 (1.0013–1.0085); respiratory: 1.0029 (0.9989–1.0070)
O_3, daily maximum 8-h mean over 10 ppb	Mortality, CVDs and respiratory diseases, all ages	A	CVD: 1.0049 (1.0013–1.0085); respiratory: 1.0029 (0.9989–1.0070)
O_3, daily maximum 8-h mean over 35 ppb	Hospital admissions, CVDs (excluding stroke) and respiratory diseases, age 65+ years	A*	CVD: 1.0089 (1.0050–1.0127); respiratory: 1.0044 (1.0007–1.0083)
O_3, daily maximum 8-h mean over 10 ppb	Hospital admissions, CVDs (excluding stroke) and respiratory diseases, age 65+ years	A	CVD: 1.0089 (1.0050–1.0127); respiratory: 1.0044 (1.0007–1.0083)
O_3, daily maximum 8-h mean over 35 ppb	MRADs, all ages	B*	1.0154 (1.0060–1.0249)
O_3, daily maximum 8-h mean over 10 ppb	MRADs, all ages	B	1.0154 (1.0060–1.0249)
NO_2, annual mean over 20 $\mu g/m^3$	Mortality, all (natural) causes, age 30+ years	B*	1.055 (1.031–1.080)
NO_2, annual mean	Prevalence of bronchitic symptoms in asthmatic children aged 5–14 years	B*	1.021 (0.990–1.060) per 1 $\mu g/m^3$ change in annual mean NO_2
NO_2, daily maximum 1-h mean	Mortality, all (natural) causes, all ages	A*	1.0027 (1.0016–1.0038)
NO_2, daily maximum 1-h mean	Hospital admissions, respiratory diseases, all ages	A	1.0015 (0.9992–1.0038)

APPENDIX C:

Partial listing of evidence establishing association between residential proximity to refineries and adverse health outcomes

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Bay Area Air Quality Management District
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VIA EMAIL
vdouglas@baaqmd.gov
Victor Douglas

May 8, 2017

Re: Health impacts and implications should be included in the No Project and alternative scenarios and the environmental and regulatory settings sections of the EIR for BAAQMD Rule 12-16

We are writing to encourage the Air District to include a comprehensive health and safety assessment in the final EIR of Rule 12-16, as detailed in the following submission. In particular, by providing a preliminary assessment of potential mortality impacts in the absence of Rule 12-16's preventive measures, this submission demonstrates the feasibility and importance of including a health assessment in the EIR. It is important that such an assessment account for:

- the preventive nature of Rule 12-16
- the influx of heavier crude oil feedstock that is projected in the absence of emissions caps
- resulting exposures and impacts on vulnerable populations, including people who live in proximity to the refineries, have low socio economic standing and / or disadvantaged racial identity, are infants, young children or the elderly, live in already polluted settings, and/or have underlying health conditions

Respectfully
Signatures, listed alphabetically on the following page,

Claire V Broome MD	Adjunct Professor, Rollins School of Public Health Emory University Assistant Surgeon General, US Public Health Service (retired)
Wendel Brunner MD, PhD, MPH	Former Director of Public Health, Contra Costa Health Services
Robert M. Gould, MD	President, Physicians for Social Responsibility, San Francisco Bay Area Chapter Associate Adjunct Professor, Program on Reproductive Health and the Environment, Dept. of Obstetrics, Gynecology & Reproductive Sciences UCSF School of Medicine (for identification purposes only)
Jonathan Heller PhD	Co-Director and Co-Founder, Human Impact Partners Oakland CA
Richard J Jackson MD MPH	Former California State Public Health Officer Director, CDC National Center for Environmental Health (retired)
Janice L Kirsch MD MPH	Medical oncologist and hematologist
Raymond Neutra MD DrPH	Chief Division of Environmental and Occupational Disease Control, California Department of Public Health (retired)
Thomas B Newman MD MPH	Professor Emeritus of Epidemiology & Biostatistics and Pediatrics, University of California, San Francisco (for identification purposes only)
Bart Ostro PHD	Former Chief of Air Pollution Epidemiology Section, California EPA, currently Research Faculty, Air Quality Research Center, UC Davis
Linda Rudolph MD MPH	Director, Center for Climate Change and Health, Public Health Institute Oakland, CA
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Patrice Sutton, MPH	Research Scientist, Program on Reproductive Health and the Environment, University of California, San Francisco (for identification purposes only)

Coordinated by

Heather Kuiper DrPH MPH	Public Health Consultant, Oakland CA

May 8, 2012

To the Bay Area Air Quality Management District Board:

This submission alerts the Air District that the Rule 12-16 draft EIR does not adequately analyze or discuss the health impacts that were identified in a letter submitted December 2, 2016 during the Notice of Preparation and Initial Study for the Rule 12-16 DEIR. In particular, the draft EIR does not adequately recognize the preventive nature of Rule 12-16, thus omitting health implications from the "No Project" alternative.

Preventing increases in harmful exposures is a well-established health protection measure. (Curie 2011, Pope 2009, Goodman 2002, Hedley 2002, Dominici 2006). A preventive approach to air quality is important, due to an otherwise anticipated increase in Bay Area refineries' use of heavier, dirtier oil feedstock, [1] (BAAQMD 2012a) which will lead to higher exposures to fine particulate matter (PM2.5). PM2.5 is definitively established as a cause of adverse health impacts, including mortality. Given the dense population of the Bay Area, increased PM2.5 will have large population impacts, presenting a major public health threat. Rule 12-16 is an important public health tool as it caps refinery emissions at current levels, thereby preventing increases in exposure to PM2.5.

Omission of the No Project Alternative (not implementing Rule 12-16) and its health impact

Because Rule 12-16 is a preventive measure, the Air District can anticipate that the "No Project" scenario will increase mortality in the Bay Area population, especially among the disadvantaged. The assessment,[2] detailed in Appendix A, measures the impact of long-term exposure to increased PM2.5 resulting from transitions to heavier oil feedstock. Adjusting for other exposures, it finds that:

- **Rule 12-16 could cumulatively prevent 800 to 3000 deaths of Bay Area residents given a refinery facility lifetime of 40 years following conversion to heavier crude**
- **The additional mortality burden for the Bay Area's disadvantaged residents could be 8 – 12 times that of the Bay Area's general population**
- **Annual monetary valuation of these deaths alone could reach up to $123.2 million, or cumulatively, up to $4.84 billion dollars. (CAP, 2017 p C/7)**

This assessment is conservative in its parameters and many of the model parameters are drawn from BAAQMD's own work. For example, it does not consider indoor air exposures, which may be higher, (Brody, 2009), impacts of ultrafine particulates (Ostro, 2015), or increased combustion, production, and handling of pet coke (US EPA). The submitted analysis is also conservative in scope: It does not include PM2.5-related morbidity, neurological, cognitive, and developmental impairment, (especially of children), hospitalizations, lost productivity, reduced activity, and health-related socio-economic impacts. Significantly, the analysis does not include health impacts associated with flares and other acute PM2.5 exposures, including mortality, cardiac events, hospitalizations, and increased susceptibility to adverse health conditions from the underlying stressors of living in proximity to pollution sources (DeFur 2007, Cutchin 2008, Luginaah 202). It also does not include the significant local climate-related

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[1] This assessment is predicated on a finding that, without 12-16, Bay Area refineries will likely undergo large-scale capital conversions for refining heavier crude oils and natural bitumen (including and especially tar sands crude), resulting in increased PM2.5 emissions and toxicity, and increased greenhouse gas emissions. (BAAQMD 2012a, Karras, 2016)

[2] This assessment draws from calculations of emissions increases attributable to heavier crude oil feedstock produced by Greg Karras of Communities for a Better Environment (Karras, 2016) It was conducted in collaboration with CBE.

health hazards and impacts that will be attributable to the Bay Area's increased refining of heavier crude feedstock.

Even so, this analysis demonstrates that is reasonable and feasible for the District to develop and consider health impact projections in its final EIR. The signatories request that the Air District include the attached assessment (Appendix A) in its final EIR and also supplement it with estimates of additional health impacts attributable to increased PM2.5 and greenhouse gas emissions, especially for vulnerable populations. See also Appendices B, and C for information that can support such additional analysis.

Modify the draft EIR's assessment of alternatives

Emission intensity caps (Rule 13-1) and mass emission caps (Rule 12-16) are complementary measures and their combination could protect health better than Rule 12-16 alone. This alternative is not considered in the draft EIR although Rule 13-1 is discussed in combination with Rule 11-18. CEQA requires an alternative to accomplish the main objectives of the project at hand, yet Rules 13-1 and 11-18 do not provide health protection equivalent to 12-16. Rule 11-18 targets various toxic air contaminants but not greenhouse gases and particulate matter and is fundamentally different in terms of health protection strategy and outcome. Rule 13-1, *as currently drafted*, omits direct control of PM2.5 and could allow facility-wide refinery emissions to increase; it is does not provide protections comparable to Rule 12-16. Regardless, it is premature to consider Rule 13-1 in the Rule 12-16 EIR.

Expand the existing environmental and regulatory settings assessments

The following considerations should be included in the environmental settings assessment:

- Cities in the San Francisco Bay Area are among the most polluted in the U.S. (ALA, 2017) High baseline air pollution augments susceptibility to adverse health threats. Due to this baseline condition, Bay Area residents will likely experience augmented health risk and burden from increased emissions. Further, the Air District, Cal EPA, the US EPA and the World Health Organization, all find that, "people exposed to PM at levels below the current EPA standards may still experience negative health effects." (BAAQMD, 2012 p 17). There are no safe levels of particulate matter, and given high baseline pollution, every PM2.5 exposure increment will contribute to increased risk of mortality, morbidity, and lost productivity for Bay Area residents.

- This high baseline pollution is not uniformly or fairly distributed, "PM concentrations – and population exposure to PM – can vary significantly at the local scale… People who live or work near major roadways, ports, distribution centers, or other major emission sources… may be disproportionately exposed to certain types of PM (e.g. ultrafine particles)…" (BAAQMD, 2012, p 14) There is growing evidence that proximity to oil refineries places residents at disproportionate risk for adverse health outcomes. Appendix C provides a partial list of this evidence base. There is also documentation that residents in proximity to refineries are disproportionately vulnerable by virtue of race, economic standing, and higher prevalence of underlying health conditions (Cushing 2016, Pastor 2010). The final EIR should recognize as part of the current landscape that failure to prevent increased refinery emissions will have environmental justice repercussions since they will predominantly occur in communities where residents are low income and/or are people of color and already disproportionately burdened by poor underlying health and multiple-source pollution exposures.

- The draft EIR should recognize that state and local policy specifically precludes placing disproportionate burden on impacted, disadvantaged populations. Senate Bill 32 and Assembly

Bill 197 recognize and protect these populations by requiring consideration of equity and social costs in reducing greenhouse gases and equitable resolution of them, prioritizing direct emissions reductions at large stationary sources. CEQA and the District's own mission also affirm a health mandate. Protecting public health and eliminating health disparities are stated goals of the 2017 Clean Air Plan. Rule 12-16 should be understood in light of this state-level policy framework for environmental health protection and the District's own mission.

- Current conditions with regards to Bay Area emissions are not static. Instead, the setting for Rule 12-16 is trending toward increases in the processing of heavier, higher-emitting, lower quality crude oils, expansion of projects to do so, and expanding fossil fuel export. (BAAQMD, 2013) Switching to heavier crudes will inherently increase emissions of PM2.5 and greenhouse gases, making it imperative that measures be put in place to prevent these future increases in emissions, *in addition to* measures decreasing current emissions. Without the preventive caps offered by Rule 12-16, other District measures will be limited by a context of rising emissions.

- The corresponding increase in fossil fuel exports will lead to an increase in exogenous air pollution in the Bay Area since a portion of the byproducts of combustion of fossil fuels exported from the Bay Area will return to us from Asia through transpacific atmospheric transport. This exogenous air pollution will directly threaten health and also impede progress toward the targets and goals of the Clean Air Plan, 2017. Exogenous / overseas sources of pollution are of increasing concern as they have been directly implicated in deaths in local populations and documented as a greater proportion of exposure than locally-sourced pollution in some settings. (Annenberg 2014, Christensen 2015, Zhang 2007, 2008, 2009).

Lastly, the health comments submitted to the District in December 2016 were omitted from Appendix A of the draft EIR and we ask that they be included.

The signatories believe these adjustments are necessary for the EIR to be complete and accurate and respectfully request they be made in time for Rule 12-16's potential adoption in September.

APPENDIX A:

Impact of Rule 12-16 on mortality associated with exposure to PM2.5 from processing heavier oil in Bay Area refineries

Table 1 Potential health impact of 12-16: Averted all-cause deaths attributable to chronic exposures to oil refinery PM2.5 (see Appendix for calculations)

	Regional Population (9 Bay Area Counties)			Impacted Population* (<=2.5 miles from refinery)		
	Low	Med	High	Low	Med	High
PARAMETERS						
Risk						
a. Risk of all-cause death for adults (>30 yrs) per 1$\mu g/m^3$ PM2.5 increase in long-term exposure	1.008	1.01	1.012	1.008	1.01	1.012
b. Incremental Risk: risk of all-cause death for adults attributable to increment in long-term PM2.5 exposure (risk/ per 1$\mu g/m^3$ *PM2.5 increase)*	*0.008*	*0.01*	*0.012*	*0.008*	*0.01*	*0.012*
Exposure						
c. Baseline anthropogenic** exposure ($\mu g/m^3$ $PM_{2.5}$)		5.7			5.1	
d. Proportion of baseline anthropogenic exposure attributable to baseline refinery activity		.05			0.5	
e. Percent change from baseline anthropogenic emissions due to higher emitting oil emissions	40%	70%	100%	40%	70%	100%
f. Conversion factor (change in PM2.5 exposure per change in PM2.5 emissions)		0.5		0.4	0.5	0.6
g. Averted exposure: the annual increased PM2.5 concentration attributed to heavier oil that is averted by Rule 12-16 ($\mu g/m^3$ $PM_{2.5}$*)*	*0.057*	*0.10*	*0.143*	*0.408*	*0.893*	*1.53*
Population and Mortality						
h. Adult Population (>25)		5,144,345			81,666	
i. Base all-cause adult death rate / person / year		*0.0083403*			*0.0091899*	
IMPACT						
j. Prevented adult all-cause deaths due to 12-16 averting increases in heavier oil PM2.5 emissions***	**20**	**43**	**73**	**2**	**7**	**14**
k. Rate of prevented adult all-cause death due to 12-16 averting increases in heavier oil PM2.5 emissions /100,000 population /yr	**0.38**	**0.83**	**1.43**	**3.00**	**8.21**	**16.88**
l. Cumulative prevented deaths due to 12-16 (40 yrs)	**800**	**1700**	**2900**	**98**	**270**	**550**

* The distance of 2.5 miles was selected to correspond with findings from Brody (2009) and Pastor (2010). Those living < 2.5 miles of refineries (Table 5) can roughly be interpreted as a proxy for impacted, vulnerable, and/or Environmental Justice populations. The Air District's CARE program prioritizes communities and populations most impacted by air pollution, i.e., those with higher air pollution levels and worse health outcomes for diseases affected by air pollutions. Vulnerable populations also include those with heightened vulnerability to PM due to age (<5, elderly), low SES, minority race/ethnic status, and underlying health conditions. This proxy is conservative because *disparate impacts on vulnerable populations may occur beyond 2.5 miles.*

** Anthropogenic exposure is the ambient PM2.5 concentration above background levels (e.g., from sea salt).

*** Annual and cumulative deaths are presented as whole numbers. The resulting rounding error explains any discrepancy between presented deaths and rate.

Notes for Table 1

a. For every 1µg/m3 PM2.5 increase in exposure there is x% increased risk of all-cause mortality, e.g., a 1% increased risk of all-cause death per 1µg/m3 PM2.5 exposure increase. Risk estimates are from BAAQMD's literature review, of for example Pope et. al (2002), Krewsk et. al, (2000), and others. Risk may be underestimated as it does not account for 1) greater energy intensity and toxicity of PM2.5 associated with heavy oil and natural refining, 2) ultrafine PM, and 3) greater vulnerability of impacted populations.

b. Calculated as (all cause death risk in exposed) – (all cause death risk in unexposed), i.e, (risk per increase of 1µg/m^3 PM2.5) – (no increase in exposure) = 1.01 – 1 = .01. For every exposure change of 1µg/m^3 PM2.5 there is a corresponding 1% change in all-cause mortality attributable to PM2.5

c. _Regional_: CAP 2017 p C/7

Impacted Population (<2/5 miles from refinery): From Brody et. al.(2009) baseline PM2.5 exposure was directly measured in Richmond at distances approximately 2.5 miles from the dominant $PM_{2.5}$ source in the refinery. To isolate exposure above background, control site measures in Bolinas were subtracted from Richmond measures, yielding µg/m3 PM2.5. The PM2.5 was chemically fingerprinted to the refinery, finding, for example, high levels, of vanadium and nickel, which in this setting are isolated to refinery emissions (versus traffic). Validating this measure, CARB "ADAM" data for 2013 subtracts annual mean PM2.5 measures at Pt. Reyes from measures at the monitoring station nearest to the refinery, yielding 5.04 µg/m3 PM2.5. A baseline exposure of 4.5 µg/m3 PM2.5 likely underestimates annual exposure because 1) the Brody study was conducted during the summer when PM2.5 concentrations are lowest and 2) Due to wind patterns, and refinery distribution, populations near the other refineries may experience a concentrating of PM2.5. For these reasons, a conservative adjustment was made to factor in higher wintertime concentrations. The annual median concentration was divided by the median concentration Apr–Sep for three years of monitoring at the three closes sites (San Pablo, Vallejo, Concord). The mean of the resulting ratios was multiplied by the Brody measure (2009) such that 4.5 x 1.13 = 5.1 µg/m3 PM2.5 anthropogenic [ ].

d. Portion of the baseline anthropogenic exposure that is attributable to baseline refinery activity
Regional: CAP, 2017 p 2/20
Impacted Population: We set the portion at .5 since Brody et. al. (2009) used chemical fingerprinting to find that heavy oil combustion (refineries being the predominant source in the study area) is the most important contributor, more important than traffic, to elevated anthropogenic PM2.5 concentrations in the study area (<2.5 miles from refinery). We consider this measure reasonable in light of 1) BAAQMD grid modeling that ranged from .2 - .6, 2) an independent assessment of the Districts aerial emissions intensity data (2015) found that, on a mass/$mile^2$ basis, within 2.5 miles of the refineries, the areal source strength is more than twice (0.7) the regional average for all sources (CBE, 2015), and 3) accommodation of some lofting of emissions from hot stacks (2017 Staff Report). These parameters nevertheless likely underestimate, since downwind refinery communities could experience consolidation of PM2.5 from multiple refineries. Further, statewide analyses link high exposure to refinery proximity (<2.5 miles) (Pastor et. al. 2010).

e. Karras (2016) estimated a range of annual tons of PM2.5 emissions that Rule 12-16 would avert, such that, meaning that annually, Rule 12-16 would prevent increases of 364, 728, or 1090 short tons PM2.5 / yr of heavier oil-associated emission, or 40%, 70%, and 100% from current refinery emission rates could be averted through Rule 12-16. Medium Case (0.7) is the midpoint of the 0.4 - 1.0 range

f. The conversion factor translates emissions into exposure. It is derived from the regional weighted average change in $PM_{2.5}$ exposure for a given change in direct emissions of $PM_{2.5}$. Verified by measurements and assuming a 24 hour "backyard exposure," BAAQMD modeled PM2.5 exposure change on a region-wide 4x4km grid relative to a 20% reduction in all-source PM2.5 emissions finding a range from .2 - .6. (CAP, 2017 D/13),
Regional: We applied .5 as the central measure to recognize that the location of population, emission sources, and meteorological conditions coincide. BAAQMD also applied approximately .5 for their regional average conversion. The conversion factor may underestimate impacted population exposures since refineries are strong PM2.5 emission sources near densely populated communities.
Impacted Population: For the <2.5 miles group, given population density and proximity to refineries, which are strong emitters, we used .4 for the lower bound. The upper bound, .6, may underestimate exposure for this group, given monitoring station locations.

g. The increased concentration of PM2.5 (exposure) attributed to heavier oil refining that is averted by Rule 12-16 ($\mu g/m^3$ $PM_{2.5}$). Calculated as (baseline total anthropogenic exposure) x (portion of baseline anthropogenic exposure attributable to baseline refinery emissions) x (Portion change from baseline anthropogenic emissions due to higher emitting oil emissions that is averted by 12-16) x (conversion factor). For the Medium regional case: 5.7 µg/m3 PM2.5 x .05 x .7 x .5 = *0.10* µg/m3 PM2.5. The attributable exposure may be underestimated because it does not account for: 1). NOx and SO2 PM-precursor emissions, and 2) the greater concentration of toxics associated with refining of heavy crude feedstock.

h. See Tables 2 and 3

i. Calculated as (annual deaths / total population) / yr. May overestimate or underestimate death rate over time should risk factors systematically improve or worsen.

j. Prevented deaths calculated as Attributable Risk x Attributable Exposure x all-cause per cap death rate x population. For middle regional scenario: .01 x .1 x .00589 x 7,447,686 = 44 deaths prevented by Rule 12-16.

k. Calculated as (deaths prevented / population) x 100,000 population / year.

l. Cumulative Impact calculated as deaths prevented x 40 years, since capital projects to accommodate heavier crude feedstock generally operate for 30 - 50 years. This number underestimates cumulative impact if population increases, as is anticipated.

Table 2. Bay Area communities ≤ 2.5 miles from refineries; local-scale population data [a]

Census	Refinery [b]	Tract distance to fence line (miles)		Fraction [c]	Population	
Tract	≤ 2.5 miles	closest	furthest	≤ 2.5 miles	Total	≤ 2.5 miles
3650.02	Chevron	0.5	2.5	1.00	5,462	5,462
3660.02	Chevron	2.3	3.3	0.20	6,093	1,219
3680.01	Chevron	1.5	2.5	1.00	5,327	5,327
3680.02	Chevron	2.0	2.7	0.71	3,404	2,431
3720	Chevron	1.8	3.1	0.54	7,353	3,959
3740	Chevron	2.0	2.8	0.63	4,506	2,816
3750	Chevron	1.3	1.8	1.00	4,389	4,389
3760	Chevron	0.4	1.5	1.00	5,962	5,962
3770	Chevron	0.4	2.4	1.00	6,962	6,962
3780	Chevron	0.0	3.1	0.81	3,435	2,770
3790	Chevron	1.1	3.1	0.70	6,117	4,282
2506.04	Phillips 66	2.1	3.7	0.25	3,842	961
3560.01	Phillips 66	0.0	3.5	0.71	3,759	2,685
3570	Phillips 66	1.0	5.5	0.33	3,018	1,006
3580	Phillips 66	0.0	2.0	1.00	5,298	5,298
3591.04	Phillips 66	2.0	3.0	0.50	1,932	966
3591.05	Phillips 66	2.0	3.0	0.50	4,542	2,271
3592.03	Phillips 66	1.0	3.3	0.65	6,726	4,387
3923	Phillips 66	1.0	2.0	1.00	3,102	3,102
3150	Shell &/or Tesoro	0.0	7.0	0.36	3,281	1,172
3160	Shell &/or Tesoro	0.5	2.0	1.00	1,483	1,483
3170	Shell &/or Tesoro	0.1	1.0	1.00	2,144	2,144
3180	Shell &/or Tesoro	0.7	4.7	0.45	3,267	1,470
3190	Shell &/or Tesoro	0.2	2.0	1.00	7,412	7,412
3200.01	Shell &/or Tesoro	0.0	2.0	1.00	3,615	3,615
3200.03	Shell &/or Tesoro	0.7	1.6	1.00	2,805	2,805
3200.04	Shell &/or Tesoro	0.2	2.0	1.00	6,216	6,216
3211.01	Shell &/or Tesoro	1.4	2.5	1.00	6,549	6,549
3270	Shell &/or Tesoro	2.0	6.0	0.13	6,695	837
3290	Shell &/or Tesoro	2.0	3.6	0.31	6,309	1,972
2520	Valero	1.8	3.5	0.41	4,157	1,712
2521.02	Valero	0.0	6.0	0.42	3,874	1,614
2521.04	Valero	0.0	4.0	0.63	5,536	3,460
2521.05	Valero	1.7	3.0	0.62	3,256	2,004
2521.06	Valero	0.5	2.0	1.00	4,132	4,132
2521.07	Valero	0.0	1.5	1.00	3,592	3,592
2521.08	Valero	1.0	2.0	1.00	3,165	3,165
		Sum of these tract data:			**168,717**	**121,608**

a) 2010 Census: https://factfinder.census.gov/faces/tableservices/jsf/pages/productview.xhtml?fpt=table

b) Plant or plants within 2.5 miles of part or all of the census tract, identified by current owner/operator.

c)) Estimation of population for tracts partly within a 2.5-mile radius: Tract fraction ≤ 2.5 miles = (2.5 - distance of bisection with radius in miles) ÷ (furthest distance – bisection distance in miles). Results are used to estimate the fraction of the total tract population ≤ 2.5 miles from a refinery. This method's simplifying assumption that population is distributed evenly within each tract despite geography and distance from refineries may result in overestimates or underestimates of local-scale population for those tracts that are partly within 2.5 miles of a refinery.

Table 3. Demographic and Vital Statistics for Bay Area Counties, 2013

	Age Group (years)											
Counties	<1	1-4	5-14	15-24	25-34	35-44	45-54	55-64	65-74	75-84	85+	TOTAL
Alameda												
Deaths	88	10	21	117	160	260	647	1,270	1,604	2,041	3,376	9,597
Population	19,493	76,842	190,900	203,954	232,027	231,327	222,525	191,268	111,600	55,333	28,101	1,563,370
Death Rate*	451.4	13.0	11.0	57.4	69.0	112.4	290.8	664.0	1437.3	3688.6	12013.8	613.9
Contra Costa												
Deaths	50	8	9	77	110	162	439	835	1,235	1,647	2,576	7,148
Population	12,240	49,755	146,153	145,402	129,256	143,616	163,677	140,700	86,747	42,739	21,577	1,081,862
Death Rate	408.5	16.1	6.2	53.0	85.1	112.8	268.2	593.5	1423.7	3853.6	11938.6	660.7
Marin												
Deaths	13	3	3	15	16	32	96	169	269	422	849	1,887
Population	2,334	9,858	30,334	26,078	23,766	32,876	41,089	40,325	28,899	13,245	7,460	256,264
Death Rate	557.0	30.4	9.9	57.5	67.3	97.3	233.6	419.1	930.8	3186.1	11380.7	736.4
Napa												
Deaths	6	1	1	9	10	23	51	125	188	269	511	1,194
Population	1,412	6,196	17,164	19,139	17,225	17,305	19,546	18,767	12,674	6,715	3,688	139,831
Death Rate	424.9	16.1	5.8	47.0	58.1	132.9	260.9	666.1	1483.4	4006.0	13855.7	853.9
San Francisco												
Deaths	30	4	6	40	91	172	351	749	809	1,268	2,134	5,655
Population	9,034	32,463	58,301	78,811	172,506	144,989	112,817	102,892	63,511	38,509	19,994	833,827
Death Rate	332.1	12.3	10.3	50.8	52.8	118.6	311.1	727.9	1273.8	3292.7	10673.2	678.2
San Mateo												
Deaths	19	2	5	35	52	94	257	477	673	1,102	1,920	4,636
Population	9,031	36,415	90,434	83,106	96,589	107,539	110,625	97,585	60,491	32,391	17,651	741,857
Death Rate	210.4	5.5	5.5	42.1	53.8	87.4	232.3	488.8	1112.6	3402.2	10877.6	624.9
Santa Clara												
Deaths	83	12	16	99	117	232	571	1,041	1,388	2,314	3,584	9,457
Population	24,112	95,493	245,789	228,340	264,949	282,446	270,707	211,136	126,347	68,609	32,667	1,850,595
Death Rate	344.2	12.6	6.5	43.4	44.2	82.1	210.9	493.0	1098.6	3372.7	10971.3	511.0
Solano												
Deaths	29	5	7	48	68	93	187	442	520	722	851	2,972
Population	5,127	20,641	55,419	59,872	56,830	53,419	61,449	56,360	32,286	15,914	6,731	424,048
Death Rate	565.6	24.2	12.6	80.2	119.7	174.1	304.3	784.2	1610.6	4536.9	12643.0	700.9
Sonoma												
Deaths	17	5	7	30	47	67	215	519	626	893	1,606	4,032
Population	5,070	21,413	58,627	65,627	64,121	59,350	69,251	71,808	45,050	20,879	11,874	493,070
Death Rate	335.3	23.4	11.9	45.7	73.3	112.9	310.5	722.8	1389.6	4277.0	13525.3	817.7
Bay Area												
Deaths	335	50	75	470	671	1135	2814	5627	7312	10678	17407	46578
Population	87853	349076	893121	910329	1057269	1072867	1071686	930841	567605	294334	149743	7384724
Death Rate	381.3	14.3	8.4	51.6	63.5	105.8	262.6	604.5	1288.2	3627.9	11624.6	630.7
<2.5 miles from refinery**												
Deaths	6	1	1	10	14	21	51	103	142	191	277	817
Population	1,402	5,685	16,278	16,577	15,027	15,911	18,180	15,913	9,612	4,736	2,286	121,608
Death Rate	454.9	18.5	7.9	60.9	95.7	129.4	278.1	648.0	1474.4	4039.0	12106.1	672.0

	Regional			<2.5miles		
	Death	Pop	Rt.	Death	Pop	Rt.
Adults >25 yr***	42905	5,144,345	834.03	751	81,666	918.992

*Death rates are age-specific expressed per 100,000 population. Age-adjusted rates are calculated using the 2000 U.S. Standard Population.

** Deaths in the Impacted Population (<2.5 miles from refinery) were derived using a death rate that divided Contra Costa and Solano Counties' combined deaths by their combined populations and applying this rate to the population living within 2.5 miles of a refinery for one year (from Table 2) (9,521 ÷ 1,518,002) x 121,608 = 763. This estimate may underestimate refinery effects on impacted populations because baseline death rates in communities near refineries may be greater than county-wide average rates. The age specific populations and deaths for the <2.5 miles group were arrived at by multiplying the total population by the age-specific death and population distribution of the combined Contra Costa and Solano Counties .

***The total adult deaths were adjusted to remove suicides and accidents by multiplying the unadjusted total by 6%, which represented the average and most frequent percent of deaths by suicide/accident for each county.

Population ≤ 2.5 miles from refinery fence lines estimated from census tract data. See Table 2
Source: State of California, Department of Public Health, Death Records. State of California, Department of Finance, Race/Ethnic Population with Age and Sex Detail, 2010-2060. Sacramento, CA, December 2014
State of California, Department of Finance, Race/Ethnic Population with Age and Sex Detail, 2010-2060. Sacramento, CA, December 2014.

APPENDIX B

Summary of pollutant – health outcome pairs to inform fuller health assessment of the No-Project Alternative

Table 1 Pollutant–health outcome pairs for which HRAPIE project recommends concentration–response functions (modified from WHO 2013b)

Pollutant metric	Health outcome	Group	RR (95 % CI) per 10 μg/m^3
$PM_{2.5}$, annual mean	Mortality, all-cause (natural), age 30+ years	A*	1.062 (1.040–1.083)
$PM_{2.5}$, annual mean	Mortality, cerebrovascular disease (includes stroke), ischaemic heart disease, COPD and trachea, bronchus and lung cancer, age 30+ years	A	GBD 2010 study (IHME 2013)[a]
PM_{10}, annual mean	Postneonatal (age 1–12 months) infant mortality, all-cause	B*	1.04 (1.02, 1.07)
PM_{10}, annual mean	Prevalence of bronchitis in children, age 6–12 (or 6–18) years	B*	1.08 (0.98–1.19)
PM_{10}, annual mean	Incidence of chronic bronchitis in adults (age 18+ years)	B*	1.117 (1.040–1.189)
$PM_{2.5}$, daily mean	Mortality, all-cause, all ages	A	1.0123 (1.0045–1.0201)
$PM_{2.5}$, daily mean	Hospital admissions, CVDs (including stroke), all ages	A*	1.0091 (1.0017–1.0166)
$PM_{2.5}$, daily mean	Hospital admissions, respiratory diseases, all ages	A*	1.0190 (0.9982–1.0402)
$PM_{2.5}$, 2-week average, converted to $PM_{2.5}$, annual average	RADs, all ages	B**	1.047 (1.042–1.053)
$PM_{2.5}$, 2-week average, converted to $PM_{2.5}$, annual average	Work days lost, working-age population (age 20–65 years)	B*	1.046 (1.039–1.053)
PM_{10}, daily mean	Incidence of asthma symptoms in asthmatic children aged 5–19 years	B*	1.028 (1.006–1.051)
O_3, summer months (April–September), average of daily maximum 8-h mean over 35 ppb	Mortality, respiratory diseases, age 30+ years	B	1.014 (1.005–1.024)
O_3, daily maximum 8-h mean over 35 ppb	Mortality, all (natural) causes, all ages	A*	1.0029 (1.0014–1.0043)
O_3, daily maximum 8-h mean over 10 ppb	Mortality, all (natural) causes, all ages	A	1.0029 (1.0014–1.0043)
O_3, daily maximum 8-h mean over 35 ppb	Mortality, CVDs and respiratory diseases, all ages	A	CVD: 1.0049 (1.0013–1.0085); respiratory: 1.0029 (0.9989–1.0070)
O_3, daily maximum 8-h mean over 10 ppb	Mortality, CVDs and respiratory diseases, all ages	A	CVD: 1.0049 (1.0013–1.0085); respiratory: 1.0029 (0.9989–1.0070)
O_3, daily maximum 8-h mean over 35 ppb	Hospital admissions, CVDs (excluding stroke) and respiratory diseases, age 65+ years	A*	CVD: 1.0089 (1.0050–1.0127); respiratory: 1.0044 (1.0007–1.0083)
O_3, daily maximum 8-h mean over 10 ppb	Hospital admissions, CVDs (excluding stroke) and respiratory diseases, age 65+ years	A	CVD: 1.0089 (1.0050–1.0127); respiratory: 1.0044 (1.0007–1.0083)
O_3, daily maximum 8-h mean over 35 ppb	MRADs, all ages	B*	1.0154 (1.0060–1.0249)
O_3, daily maximum 8-h mean over 10 ppb	MRADs, all ages	B	1.0154 (1.0060–1.0249)
NO_2, annual mean over 20 μg/m^3	Mortality, all (natural) causes, age 30+ years	B*	1.055 (1.031–1.080)
NO_2, annual mean	Prevalence of bronchitic symptoms in asthmatic children aged 5–14 years	B*	1.021 (0.990–1.060) per 1 μg/m^3 change in annual mean NO_2
NO_2, daily maximum 1-h mean	Mortality, all (natural) causes, all ages	A*	1.0027 (1.0016–1.0038)
NO_2, daily maximum 1-h mean	Hospital admissions, respiratory diseases, all ages	A	1.0015 (0.9992–1.0038)

APPENDIX C:

Partial listing of evidence establishing association between residential proximity to refineries and adverse health outcomes

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Victor Douglas

From: James Griggs <jrgriggs5@yahoo.com>
Sent: Monday, May 8, 2017 12:08 PM
To: Victor Douglas
Subject: Environmental Impact Report (EIR) for Rule 11-18 (HRAs and Toxic Emissions) and Rule 12-16 (Refinery GHG Caps)

Hi Mr. Douglas,

I am an employee of Chevron, working at the Richmond Refinery, and am writing to you to express my concerns about the proposed Rules 11-18 and 12-16. In 2016, the state-of-the-art systems that monitor our refinery's emissions, showed zero exceedances of federal health-based standards in Richmond. The Richmond Refinery's contribution to ozone-forming pollutants is very small compared to other sources (2% during Summer months and 12% during Winter months). The refinery poses no significant environmental, nor adverse health impact to the local area. Your organization's data states that estimated lifetime cancer risk for Bay Area residents over a 70-year lifespan from all TACs (cancer causing agents) combined, declined from 4100 cases per million in 1990, to 690 cases per million in 2014, which is an 80% decrease. Thus, I am confused as to why the two new rules are deemed to be necessary. Can you explain to me why you believe the new rules are necessary?

Thanks,

James T. Griggs

Victor Douglas

From: Kurt Liebe <kurtliebe@gmail.com>
Sent: Thursday, May 4, 2017 3:59 PM
To: Victor Douglas
Subject: BAAQMD Public Comment: Environmental Impact Report (EIR) for Rule 11-18 (HRAs and Toxic Emissions) and Rule 12-16 (Refinery GHG Caps).

Dear Mr. Douglas,

Please accept my public comment regarding the combined Environmental Impact Report (EIR) for Rule 11-18 (HRAs and Toxic Emissions) and Rule 12-16 (Refinery GHG Caps). The proposed regulations have a negative consequence on me, my family, my co-workers, and neglect the economic health of the Bay Area region.

I am a resident of Richmond, personally contribute a significant amount of tax benefit to Richmond, Contra Costa County, and California as a whole, and enjoy the benefits of living in a great and clean socio-economic environment that the Bay provides. My family and I would like to continue doing so. Specific arguments against the two rules follow.

Rule 11-18

- **While the intent of Rule 11-18 is to address concerns about health risks to refinery communities, more than 1,000 facilities will be impacted, including hospitals, schools and data centers being subjected to potentially expensive control requirements.**
  - Many businesses with emergency diesel engines could incur costs ranging from about $6,000 to $400,000. These are burdensome costs that all of society must bear.

- **Rule 11-18 lacks a clear scientific explanation for why the dramatic change in risk threshold is appropriate, especially in light of the Bay Area's dramatically improved air quality.**
  - There is no justification for the proposed 10 in 1 million cancer risk threshold.
  - The proposed 10 in 1 million cancer risk threshold is inconsistent with the State's threshold of 25 in 1 million
  - The average Bay Area risk from *exposure* to TACs has been reduced by 83%; and
  - Over the last few decades TAC *emissions* from stationary sources in the Bay Area have decreased by 87%.

- **Rule 11-18 is likely to result in little or no real improvement on risks to public health.**
  - Only 4% of acute toxicity weighted emissions in the Bay Area come from industrial & commercial equipment – the equivalent percentage of emissions as recreational boat usage.
  - Vehicles and wood smoke are a significant cause of air emissions and are ignored in the rule.

- **Rule 11-18 creates concern and confusion due to inconsistencies with prior enacted Rules and lack of sufficient outreach and education with the business impacted.**

Emissions from cargo carrier should not be included in refineries' emissions as they do not control the owners and operators of the ship.

Rule 12-16

- **Refineries already have permit limits, emission limits, and mass limits verified with analyzers.**
- **Greenhouse gases are already regulated by the California Air Resources Board (CARB) so this is an unnecessary duplication.**
- **CARB's Cap and Trade program is working and a local cap will lead to higher global green house gases.**

Thank you for considering my comments regarding BAAQMD Rules 11-18 and 12-16. BAAQMD and I share a passion for the health of everyone living in the Bay Area. However, existing rules in place provide a level of protection and world class environmental leadership that does not require further modification and restriction.

Sincerely,

Kurt D. Liebe, PE
508 Sea View Drive
Richmond, CA 94801
kurtliebe@gmail.com

From: Laurie Ropel <laurieljr@yahoo.com>
Sent: Monday, May 8, 2017 1:42 PM
To: Victor Douglas
Subject: Rule 11-18 and 12-16 EIR Comments

Dear Mr. Douglas,

I am concerned that the Rule 11-18 and 12-16 EIR does not adequately address environmental impacts of these rules.
1. The EIR's project description is supposed to be consistent with the currently proposed rules, but instead the project description is based on a previous draft of the rules.
2. The EIR does not adequately address the environmental impacts of the rules because the equipment that will be installed in order to comply with the rules has not been determined yet.
3. The EIR does not include the full scope of businesses that will be impacted by Rule 11-18. How were restaurants evaluated against the 10 in 1 million risk threshold? Several restaurants that cook meat, known to produce toxic polycyclic aromatic hydrocarbons, are located adjacent to or very close to residences. Rule 11-18 may set requirements for restaurants that the restaurant industry has not been informed of.
4. I am concerned that the EIR inadequately addresses greenhouse gas emissions associated with Rule 12-16. The District Advisory Council concluded that rule 12-16 has the potential to increase global GHG emissions when the Bay area needs to import fuels to meet demand, because the Bay Area refineries reached their capped GHG limits. The EIR does not adequately inform the public or address the global GHG increases that likely would result from this rule. The California cap and trade program would not prevent emissions from shipping fuel from overseas.

Sincerely,
Laurie Mintzer
Resident of Contra Costa County

From: Lucas Mejicanos <mejiclm@yahoo.com>
Sent: Monday, May 8, 2017 4:47 PM
To: Victor Douglas; mejiclm@yahoo.com
Subject: Comments Proposed regulation 12, Rule 16: Petroleum Refining Facility -Wide Emissions Limits

Mr. Victor Douglas, Bay Area Air Quality Management
District, 375 Beale Street, Suite 600, San Francisco CA, 94105

Issue: data shown in EIR - Table 3.2.2 Bay Area Air Pollution Summary -2015 shows the Martinez and Richmond Area with no data or very scattered. These are the locations with the biggest refineries in the Bay Area!

Comment: how the limits are being set for this regulation with very poor and non-representative data. Other areas like San Ramon have more concerning levels of pollution, but they are not addressed by this EIR and proposed regulation. Please explain.

Thank you,

Lucas Mejicanos

From: Lynn Rice <lynnrice@gmail.com>
Sent: Thursday, May 4, 2017 8:25 AM
To: Victor Douglas
Subject: Questions on EIR

Mr. Victor Douglas,

As a resident of East Richmond, I was reading through the BAAQM's draft EIR and have a couple questions:

- Considering the spatial distance between your monitoring stations and the variation in weather and wind currents, is it accurate to simply take an average of measured pollutants and use that model to calculate air quality metric compliance or is more sophisticated modeling and mapping required? For example, I feel that, in my location, the air quality in San Rafael would be much more impactful to the quality in my neighborhood than that in San Ramon.
- I noticed that the City of Richmond has very little data available. Could you advise on why this data is absent?

Thank you in advance for your feedback,

Lynn Rice

5411 Clinton Ave.

Richmond, CA 94805

Victor Douglas

From:	mjjohnsonwp99@gmail.com
Sent:	Monday, May 8, 2017 6:14 AM
To:	Victor Douglas
Subject:	EIR Comments

Mr. Douglas,

I'm writing to comment on the EIR on newly proposed regulations posted on your website (Rule 11-18 and 12-16). In several instances, the evidence and facts presented does not appear to support the issue. I've included a few examples below:

In paragraph 1.4.1.1 it states there were only 12 days where the stated air quality standard was exceeded in 2015 as measured by the Air District. This occurred in Livermore, Patterson Pass, and San Ramon. Those areas, however, will not be addressed by the proposed rules on refineries. Air Quality data does not appear to support the need for the proposed regulations. If this is not the case, additional air quality data should be presented for the areas most impacted by refinery operations in north and west Contra Costa County. If the data is not available, independent studies should be conducted to understand it better.

Table 3.2-2 Bay Area Air Pollution Summary – 2015 shows Richmond (the city with the largest refinery in CCC) as having the cleanest air in the county. How can this be? Was data omitted from the report? In order to present a thorough and detailed case, this data must be included in the report.

Page 1-10 states that it is impossible for the Air District to predict gasoline consumption in 2018 and how it would relate to refinery capacity along with how the market could react if refineries were constrained under Rule 12-16. This is a glaring gap in the EIR. Models are available and there are consultants/companies that can be hired to deliver a much more thorough analysis of market conditions and the impact of the rule. More time needs to be spent here prior to considering such regulations. If market conditions cannot be predicted, then how can you propose to limit refinery production through further emission controls? I am already paying too much for gas and very concerned your failure to conduct the proper research could increase the cost further or otherwise unnecessarily constrain supply. You must conduct a thorough study to understand this better. Stating it is simply unpredictable is irresponsible, especially since demand for refinery products is increasing. Please take the time and spend the money necessary to do this analysis right.

For rule 11-18, according to Air District data, diesel particulates are the leading emission that causes cancer. However, refineries are not the primary source of this emission. Mobile sources and the power industry outpace refineries according to the Air District. Also, the port of Oakland and vicinity has a higher cancer rate than any other area in the East Bay. The EIR should provide additional detail to explain why the district is not including the Port of Oakland or the other leading causes of diesel particulate emissions if reducing cancer risk is the real issue of concern. The rule appears to specifically target refineries which are not the leading emitter of diesel particulates. This makes your report appear biased, which is unfortunate.

I hope you take the time to ensure an accurate report is presented to the public after review and amendment. It currently appears to be incomplete and poorly supported.

Sincerely,
Matthew Johnson
Contra Costa County Resident

Sent from Mail for Windows 10

From: Nicole Mendoza <nikkirevecho@gmail.com>
Sent: Monday, May 8, 2017 3:00 PM
To: Victor Douglas
Cc: vrobles@chevron.com
Subject: Comment Regarding EIR for proposed Rules 12-16 and 11-18

May 8, 2017

Attention Mr. Victor Douglas
Bay Area Air Quality Management District
375 Beale Street, Suite 600
San Francisco, CA 94105
vdouglas@BAAQMD.gov

RE: Comment Regarding EIR for proposed Rules 12-16 and 11-18

To Whom It May Concern,

I write in question of the Environmental Impact Report (EIR) for proposed rules 12-16 and 11-18 alleged to address air pollution and protect public health and the global climate.

- Table 3.2-2 – there is no data to represent the city of Martinez, Benicia or Rodeo and almost no data at all to represent the city of Richmond; all cities that have running refineries. Why is that? Chevron has fenceline monitors that have been in place since at least 2014 which should provide data for the ozone, monoxide and dioxide pollutants. I suggest adding the data captured from the fenceline monitors in Richmond and provide data from other cities that house refineries to accurately depict the air quality in those areas since refineries are the biggest targets in the proposed rules 12-16 and 11-18.
- Section 1.4.1.1 Air Quality Setting – indicates that The State 8-hour standard was exceeded on 12 days in 2015 in the Air District; most frequently in the Eastern District (Livermore, Patterson Pass, and San Ramon). The federal 8-hour standard was exceeded on 12 days in 2015. None of these excesses occurred in areas in or around refineries, indicating mobile sources are once again the major contributors to polluters in the Bay Area. Seems as though much of this effort focuses on refinery's whereas if there were more stringent regulations around mobile sources, there would be more significant improvement in air quality if that were the real intention.
- Table 3.2-4 – indicates that petroleum refining and processing is one of the smallest contributors of pollutants because they are already so heavily regulated. If improving the air quality and health are really the focus, why not drive more attention to regulating mobile sources (the worst polluter indicated over and over again in all of the tables and charts you provide)? Suggest more effort be put towards the regulation of mobile sources to see actual and substantial improvements in air quality.

While I applaud the effort put forward to improve air quality in the Bay Area, I question the focus that so heavily relies on limiting refinery production when mobile sources are the worst contributors.

Thank you for your consideration.

Sincerely,
Nicole M. Mendoza
Richmond Resident

Phillips 66
San Francisco Refinery
1380 San Pablo Avenue
Rodeo, CA 94572
phone 510.799.4411
fax 510.245.4476

May 8, 2017

ESDR-150-17
05-C-03-G

VIA Email

Mr. Victor Douglas (VDouglas@baaqmd.gov)
Manager, Rule Development Section
Bay Area Air Quality Management District
375 Beale Street, Suite 600
San Francisco, CA 94105

RE: Phillips 66 Company: Comments on BAAQMD's DEIR for Regulation 12, Rule 16 and Draft Regulation 11, Rule 18

Mr. Douglas:

Phillips 66 Company (Phillips 66) is providing comments in this letter related to the Draft Environmental Impact Report (DEIR) for two new Bay Area Air Quality Management District (District) rules currently being developed – Regulation 12, Rule 16: Petroleum Refining Facility-Wide Emission Limits (Reg. 12-16) and Regulation 11, Rule 18: Reduction of Risk from Air Toxic Emissions at Existing Facilities (Reg. 11-18).

In addition, Phillips 66 supports and adopts the comments of the Western States Petroleum Association (WSPA) and the California Council for Environmental and Economic Balance (CCEEB) on the above-referenced Regulations submitted on May 8, 2017.

Regulation 12, Rule 16

The California Environmental Quality Act ("CEQA") requires that the District's Environmental Impact Report for the project consider the entire project. As you are aware, the CEQA Guidelines define a "project" to be the whole of an action, which in this case includes all regulations associated with Board Resolution 2014-07 targeting emissions reductions from refineries. The District has not included all of these other regulations in the project description or even evaluated their cumulative effects.

There is a reasonable likelihood that proposed Regulation 12, Rule 16 will curtail refinery production below levels already achievable in practice and currently permitted, which infringes on Phillips 66's vested rights. The proposed rule severely inhibits (or may altogether prevent) the ability of Bay Area refineries to build new equipment or process units that may be required to meet future Federal and/or California Air Resource Board (CARB) fuel standards or to respond to increases in demand. These factors make it reasonable to assume that Regulation 12, Rule 16 may make one or more refineries obsolete and potentially force their closure which would lead to increased import of motor fuels from out of the Bay Area. In light of this, the District needs to evaluate the environmental, socioeconomic and other factors associated with restricting refinery operations. The potential to affect fuel supply in the Bay

Area must be thoroughly evaluated. For instance, the District must evaluate the GHG impacts of importing gasoline from outside the State or from foreign countries should a fuel shortage be caused or exacerbated by proposed Reg 12-16. These potential impacts were not evaluated in the DEIR.

Adoption of the proposed Regulation 12, Rule 16 would be beyond the Board's legal authority. District Staff has arrived at this same conclusion (*BAAQMD Draft Staff Report*, pages 3, 19, and 20). If the Board adopted this proposed rule, it would be a transparent attempt to utilize legislative authority that the Board does not rightfully have, which will have been hijacked by the Board solely to impose the Board's own purported policy choices on a discreet sector of the economy and regulated community.

Regulation 11, Rule 18

No significance criteria for toxic air contaminants (TACs) (i.e. cancer risk, acute and chronic HI) are included in the DEIR. It is not possible to properly determine impacts if there are no significance criteria. Page 3.2-47 claims that increased ammonia emissions resulting in increased acute and chronic HI would be less than significant, but no significance threshold is shown. The District needs to include significance criteria in the DEIR with a discussion detailing why the criteria proposed is relevant. The EIR will be deficient without the significance criteria.

One of the stated objectives of Regulation 11-18 in the DEIR is to "Ensure the facilities that impact the most sensitive and overburdened communities reduce their associated health risk in an efficient and expeditious manner". However, the DEIR fails to clearly define or even describe where the "most sensitive and overburdened communities" are. As the District is aware, there is a Community Air Risk Evaluation (CARE) program study that the District initiated. The CARE study report designates certain communities that could meet the "sensitive and overburdened" criteria. There is no mention of the CARE study in the DEIR as it relates to Regulation 11-18. It should be noted that the results of the CARE study indicate that refineries are not the main contributors to public health risks from air toxics in part because not all of the refineries are located in CARE communities. As such the DEIR fails to provide information related to such simple questions as what specific sources or sources types are located in or near the "sensitive and overburdened" communities? The DEIR must provide a more thorough description of what communities they are protecting to satisfy the DEIR's stated objective for the proposed Rule. The EIR will be deficient without this analysis.

The District did not provide a thorough scientific justification for why a risk threshold of 10 in a million (10/M) was arbitrarily chosen and a justification should be included. The District's own Community Air Risk Evaluation (CARE) study estimated that average background air quality in the Bay Area is roughly 50 times greater than the proposed risk threshold of 10/M. The District must determine if the Rule is implemented whether or not all reducing risk from all facilities to below 10/M would even have a significant effect on the overall risk from background air quality.

District staff had previously reported a 25/M risk threshold to the Board, but this threshold has been removed and replaced with the 10/M threshold without any explanation. The District should include an explanation. The EIR will be deficient if a more thorough analysis and justification is not included in the document. The analysis should include consideration of a valid significance threshold for health risk to put the 10/M and 25/M risk thresholds in proper perspective.

The *BAAQMD Draft Staff Report* explains that the District will use the annual toxic emissions inventories reported to the District to conduct site-specific HRAs for sources that emit toxic compounds. Section 11-18-403.3, in turn, requires the Risk Reduction Plan to include a source characterization that includes "summary data from the applicable APCO-approved air toxic emission inventory." However, proposed Rule 11-18 provides no further clarity with respect to the emissions inventory component. To help ensure consistency in emission inventory and health risk assessment methods across facilities, Phillips 66 requests that Rule 11-18 clarify that the emission inventory is based on actual emissions, not potential to emit.

The BAAQMD did not provide guidance and a more thorough review of proposed Regulation 11, Rule 18 (Reg 11-18) in relation to the recent changes to Regulation 2-5 and Regulation 2 Rules 1 and 2 (Regs 2-1& 2). These regulations will all potentially have effects on the other regulations and should be thoroughly reviewed to determine if there are any inconsistencies or other potential issues. The EIR will be deficient without considering these issues.

- For instance, potential risk reductions required by Reg 11-18 may require permits and review via Regs 2-1 & 2 and Reg 2-5. What are the effects if Reg 2-5 required TBACT on a project being conducted for Reg 11-18 compliance, when currently Reg 11-18 only requires TBARCT?
- What if a project is required by proposed Reg 11-18 risk reduction requirements but is not issued a permit pursuant to proposed Reg 2-5 because the potential to emit only for the project is included in the Reg 2-5 analysis? Is the facility then out of compliance with Reg 11-18?

TBARCT should be better defined as part of the Reg 11-18 rulemaking. Defining TBARCT is necessary to prepare the socioeconomic analysis and determine the range of probable costs, define the impact of the rule on regional employment and economy, determine the availability of cost-effective alternatives and quantify the emission or risk reduction potential of the rule. Moreover, this would help inform regulated businesses about what would be required and what compliance options are available, which in turn could prompt useful public participation and comments on the draft rule. The current definition of TBARCT in 11-18-204 does not adequately consider cost-effectiveness, as it requires installation of the most stringent retrofit emissions controls available. The DEIR further does not address environmental impacts from all the identified most likely types of control technologies listed in Table 2.5-2. Only a select handful are evaluated, rendering the analysis incomplete. The DEIR should include an analysis of the impacts form all technologies.

The District's choice of facility prioritization for implementation of the proposed Rule appears arbitrary. Multiple times in the *BAAQMD Draft Staff Report*, CARE communities are noted as the areas with the highest risk; however, the District did not consider the CARE communities when determining the prioritization. Further, diesel PM is the largest contributor to Bay Area risk as illustrated in Figure 5 of the *BAAQMD Draft Staff Report*, however, the primary stationary source of diesel PM emissions, diesel engines, are not proposed to be addressed by the rule until the third implementation phase, and reductions from these sources won't be implemented until 2024 at the earliest. The District should prioritize implementation of facilities that are located in CARE communities because they are the areas with the highest overall risk. The EIR will be deficient without an analysis that considers alternative prioritization.

If you have any questions regarding these comments, please contact me at (510) 245-5825.

Sincerely,

Don Bristol

Don Bristol
Environmental Superintendent

cc: Eric Stevenson, BAAQMD (via e-mail: EStevenson@baaqmd.gov)
Greg Nudd, BAAQMD (via e-mail: GNudd@baaqmd.gov)

Bay Area Air Quality Management District
375 Beale Street, Suite 600
San Francisco CA 94105

VIA EMAIL
vdouglas@baaqmd.gov
Victor Douglas

May 8, 2017

RE: Comments on the Draft Environmental Impact Report for Regulation 11-18: Toxic Risk Reduction Rule (Rule 11-18) and Regulation 12-16: Petroleum Refining Facility-Wide Emissions Limits (Rule 12-16)

Dear Mr. Douglas,

The Bay Area Air Quality Management District ("Air District") has an historic opportunity to address the local pollution and climate change impacts from the refining industry's shift to more polluting and hazardous oils. Over the past few years, the Bay Area has seen a flood of proposed refinery expansion projects to enable the refining of lower quality oil feedstock. Rule 12-16 (hereafter also referenced as "Emission Caps") protects public health and the climate from potentially irreversible air pollution impacts that this industry wide shift in crude oil feedstock threatens to cause.

This comment is accompanied by refinery[1] and health expert reports that demonstrate the potential for disparate and significant local health effects of this refinery oil switch. Those impacts are greater on vulnerable populations across the region, and increasingly disparate and severe on the most vulnerable communities nearest refineries. Rule 12-16 could prevent refinery greenhouse gas and particulate matter air pollution from increasing by 40–100%. Rule 12-16 could also prevent 800–3,000 premature deaths due to increasing refinery particulate pollution in the Bay Area over 40 years, and prevent a disparately severe mortality burden 8–12 times the region wide burden from pollution in communities within 2.5 miles of refineries.

Emission Caps are a reasonable, no cost and no impact preventative response that place facility wide emission limits on Bay Area refineries, preventing any combustion emission pollution increases and reducing the risk of pollution spikes from hazards such as the August 2012 Chevron Richmond Refinery fire.

Unfortunately, the Draft Environmental Impact Report for Rule 12-16 ("DEIR") largely ignores the air pollution concerns underlying the rule. As the DEIR fails to

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[1] Expert report of Greg Karras regarding the DEIR, May 2017 ("Karras 2017").

adequately acknowledge that essential issue, it cannot inform the Air District Board of Directors and the public of the significant environmental impacts that Rule 12-16 is designed to prevent. Failure to present the true purpose of Rule 12-16 directly impairs the legal defensibility of the urgently needed preventative measure. Compounding this error, the Air District mischaracterizes Rule 12-16 as a mere policy recommendation from Communities for a Better Environment ("CBE") "and their associated organizations." This prejudices any objective review of Rule 12-16. The DEIR thus fails as an informational document.

As set forth below, the DEIR suffers from numerous deficiencies that render it inadequate under the California Environmental Quality Act ("CEQA")[2] and the CEQA Guidelines.[3] We respectfully request that the Board of Directors reject the DEIR as an environmental review document, and direct staff to revise the DEIR to comply with CEQA. Furthermore, for the reasons outlined below, time is of the essence. The Air District is on schedule to meet its September 2017 hearing to consider adoption of Regulation 13, Rule 1, Facility Wide GHG Limits ("Rule 13-1"). There is ample time to revise the DEIR in time for consideration of Emission Caps and Rule 13-1 concurrently for adoption this September.

As detailed more fully below, in order to comply with CEQA, the DEIR must be corrected as follows:

1. Revise the Environmental Setting, No Project Alternative and other sections of the DEIR to disclose and evaluate the Bay Area industry trend to refining lower quality oils and the resultant foreseeable increases in pollution from Bay Area refineries;

2. Revise the Project Description and other sections of the DEIR to describe the preventative purpose of Rule 12-16, in particular regard to preventing disparately severe increases in pollution and public health impacts on vulnerable populations, especially in communities located in close proximity to refineries, and how compliance may be achieved at no cost and no environmental impact; and

3. Prepare a DEIR for both Rules 12-16 and 13-1 on the current schedule for Rule 13-1 so that both rules may be considered for adoption, and potentially together as the environmentally superior alternative to each Rule alone, in September of this year.

I. The DEIR Fails to Include an Accurate Environmental Setting

The DEIR details the existing environmental setting in the Bay Area in regards to several environmental areas: air quality; climate change and greenhouse gas ("GHG") emissions; hazards; hydrology and water quality; noise; transportation and traffic; and utilities and service systems. However, each of these sections ignores the project objectives of Rule 12-16 and therefore provides an inaccurate and irrelevant analysis of

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[2] Pub. Res. Code § § 21000 *et seq.*

[3] 14 Cal. Code Regs. § § 15000 *et seq.*

Emission Caps, placing a misplaced focus instead on the environmental impacts of the installation of pollution control equipment.[4]

As stated in the DEIR, the objectives of the Emission Caps are to:

- Protect air quality, public health, and the climate from increases in annual facility- wide mass emissions of GHGs, PM, NOx, and sulfur oxides (SOx) *caused by changes in refinery oil feed quality or quantity, refinery or support equipment or operation, or combinations of these causes*, by preventing any significant increase in these emissions;

- Protect the climate and public health by preventing any significant increase in these emissions at refineries and associated facilities *from increasing the emission intensity* of the production of transportation fuels;

- Protect community and public health by preventing any significant increase in these emissions from worsening hazards for which HRA methods may not account, including but not limited to *acute and chronic ambient PM, NOx, SOx, and PM exposure hazards*;

- Complement other air quality, public health, and climate measures by *discouraging investment in new refinery equipment that would lead to increased emissions* of GHG, PM, NOx, or SOx from Bay Area refineries.[5]

We emphasize that each of these objectives aim to address increasing combustion emissions from refinery operations processing a lower quality oil feedstock, such as Canadian tar sands-derived oils, and other similarly "heavy" oils. Nevertheless, in its discussion of the Environmental Setting, the DEIR omits critical discussion of the recent Bay Area refinery expansion projects, such as the Chevron Richmond Refinery Modernization Project, that would enable increased refining of these same oils.

CEQA Guidelines § 15125(c) provides that "[k]nowledge of the regional setting is critical to the assessment of environmental impacts [and] [s]pecial emphasis should be placed on environmental resources that are rare or unique to the region." The courts have affirmed this principle, holding that the absence of accurate and complete information regarding the project setting precludes the adequate investigation and discussion of the environmental impacts of the project.[6] Evidently, the Air District has not corrected the deficiencies that we noted regarding the Notice of Preparation and Initial Study for the DEIR.[7] Again, the DEIR fails to adequately describe the environmental setting in three

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[4] We note we agree with the Air District that refinery emissions will increase in the foreseeable future. The DEIR analysis of impacts from add-on controls to meet limits already met now assumes increasing refinery emissions, but it ignores this baseline condition in all other contexts. This contradiction makes its project description unstable as further detailed below.

[5] DEIR at 2-4.

[6] *San Joaquin Raptor/Wildlife Rescue Center v. County of Stanislaus* (1994) 27 Cal. App. 4th 713.

[7] Those comments are referred to as the *December 2016 Legal Comment of 350 Bay Area, CBD, CBE, NRDC, and Sierra Club on the DEIR Scope* in this comment's recommendations, are incorporated into this comment by reference, and attached as Attachment A.

significant respects: first, by omitting the current regional crude shift to a lower quality, and more polluting, oil feedstock; second, by omitting the disproportionate impact of such increased pollution on vulnerable populations and local low-income communities of color; and third, by omitting discussion of how that impact is emphasized by the contrast of growing foreign exports of fuel and decreasing domestic consumption.

A. The Environmental Setting Must Discuss the Trend Toward Refining Increased Volumes of Lower Quality Oils in the Bay Area

As noted in the Concept Paper for this rulemaking, the quality of crude imports to the U.S. has decreased over the past decades, as refineries have imported heavier and more sulfur-rich fuel.[8] The Concept Paper continues: "the use of lower quality crude at refineries could…increase emissions of air contaminants…Emissions could also increase as a result of accidents related to the increased corrosiveness of lower quality crudes."[9]

Furthermore, in its Response to Comments on the Initial Draft of Regulation 12, Rule 15, the Air District has acknowledged that "it is reasonable to expect" that the Bay Area refineries will "follow the general industry-wide trend towards increased processing of lower quality crudes," and that processing these crudes tends to "cause more emissions."[10]

The environmental concern surrounding shifting crude quality feedstock at Bay Area refineries is consistent with industry reports and data. The Society of Petroleum Engineers concluded in 2009 that Canadian tar sands offer "the most promising source for California refineries" to replace currently dropping crude supplies.[11] In addition, several of the Bay Area refineries, including Valero, Phillips 66, and Tesoro, have issued investor reports announcing plans to import Canadian crudes.[12] The Alberta Energy Resources Conservation Board and the Canadian Association of Petroleum Producers have also announced plans to export more tar sands oil for processing by California refineries.[13] A 2007 report in Oil & Gas Journal describes industry plans to expand the market for price-discounted oil produced in the Canadian oil sands by, among other things, sending large amounts of this oil to California refineries as a new potential growth market.[14] A 2015 Canadian Association of Petroleum Producers crude oil forecast, markets, and transportation report outlines plans for exporting more tar sands oil to California refineries via pipeline, ship, and rail.[15] A 2015 report by CBE and

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[8] Petroleum Refining Emissions Tracking, Regulatory Concept Paper, *available at* http://www.baaqmd.gov/~/media/files/planning-and-research/rules-and-regs/workshops/2013/1215_dr_rpt032113.pdf?la=en.

[9] *See* Karras 2017.

[10] *Id.*

[11] *Id.*

[12] *Id.*

[13] *Id.*

[14] *Id.*

[15] *Id.*

ForestEthics identifies oil industry projects which could potentially replace up to 40–50% of California refinery crude feed by rail alone.[16]

Moreover, the Air District has permitted a series of these very refinery expansion projects that would enable the refining of these lower quality and more polluting oils. In 2013, the Air District permitted the Kinder Morgan Richmond Terminal Crude by Rail Project; in 2014, the Chevron Richmond Refinery Modernization Project; in 2015, the Phillips 66 Rodeo Refinery Propane Recovery Project. Other similar expansion projects in the Bay Area are currently proposed, such as the Nustar Shore Terminals LLC Selby Terminal Crude Oil Project. However, these projects, and the overall trend to the refining of lower quality oil feedstock in the Bay Area, are completely omitted from discussion in the Environmental Setting of the DEIR. Pursuant to CEQA Guidelines § 15125(c), the commenters therefore make the following recommendation:

Recommendation # 1: Revise sections of the Environmental Setting to disclose: the industry trend to refining lower quality oils in the Bay Area; recent and foreseeable refinery expansion projects or capacity to refine greater quantities of lower quality oils in the Bay Area; an estimate of the potential increase in combustion emissions (GHGs, particulate matter (PM), NO_x and SO_x) that Rule 12-16 is designed to limit; and the potential for emission increases as a result of accidents that Rule 12-16 is designed to prevent.

B. The Draft EIR Environmental Setting Must Include an Assessment of the Local and Disproportionate Impact of Refinery Pollution

Importantly, Bay Area refineries do not have any overall facility limits on pollution: "none of these facilities have an explicit stated overall mass emission limits that apply to the entire refinery."[17] Although the DEIR suggests that individual permit limits for individual sources within the refinery facility effectively limit pollution, the DEIR also admits that *all* Bay Area refineries have "grandfathered" emission sources that were not subject to New Source Review.[18] By then mentioning that these same sources are also governed by Air District regulations, the DEIR misleads the public into believing that aggregating these individual source limits would essentially produce the same result as the proposed Emission Caps. In reality, however, aggregating individual source limits produce limits far above those set by Emission Caps, and far above the current production capacity of each Bay Area refinery.[19] Aggregating individual source pollution limits therefore sets an overall facility-wide limit so impractically high that it is, in reality, no limit at all.

The commenters therefore make the following recommendation:

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[16] Krogh et al., 2015. Crude Injustice on the Rails: Race and the Disparate Risk from Oil Trains in California; report by Communities for a Better Environment and ForestEthics. June 2015, *available at,* http://www.forestethics.org/news/crude-injustice-rails-california.

[17] DEIR at 3.2-16

[18] *Id.*

[19] This fact was confirmed by Air District Staff at the 30 March 2017 Open House on Emission Rules in Richmond.

<u>Recommendation # 2</u>*: Revise sections of the Environmental Setting to disclose that aggregating individual source limits does not produce effective, overall, facility-wide pollution controls on Bay Area refineries.*

This discussion is critical for the evaluation of how much pollution Emission Caps may prevent, and particularly for vulnerable populations and low income communities of color in close proximity to Bay Area refineries.

As noted in the November 11, 2016 comment on the NOP/IS submitted by CBE and other organizations, there is abundant evidence that refinery emissions disparately harm vulnerable populations, especially nearby low-income communities of color. We have illustrated several examples, including elevated indoor $PM_{2.5}$ exposures in the homes of low-income residents of color in Richmond, increased exposure to ultra-fine PM from refinery sources, and elevated concentrations of emissions during episodic emissions from incidents such as the August 2012 Chevron Richmond Refinery fire.

The DEIR notes: "combustion of fossil fuels…[is one of the] primary contributors of directly emitted Bay Area $PM_{2.5}$.[20] The DEIR also states,

> A consistent correlation between elevated ambient particulate matter (PM10 and PM2.5) levels and an increase in mortality rates, respiratory infections, number and severity of asthma attacks and the number of hospital admissions has been observed in different parts of the United States and various areas around the world. Studies have reported an association between long-term exposure to air pollution dominated by fine particles (PM2.5) and increased mortality, reduction in life-span, and an increased mortality from lung cancer.
>
> Daily fluctuations in fine particulate matter concentration levels have also been related to hospital admissions for acute respiratory conditions, to school and kindergarten absences, to a decrease in respiratory function in normal children and to increased medication use in children and adults with asthma. Studies have also shown lung function growth in children is reduced with long-term exposure to particulate matter. The elderly, people with pre-existing respiratory and/or cardiovascular disease and children appear to be more susceptible to the effects of PM10 and PM2.5.[21]

The DEIR's analysis of local impacts from refineries ends there. At the same time, however, the accompanying Staff Report inconsistently claims that $PM_{2.5}$ from refineries do not contribute to localized impacts, presenting a regional, rather than local, problem.[22] The Staff Report arrives at this faulty conclusion by ignoring evidence for

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[20] DEIR at 3.2-9

[21] DEIR at 3.2-5

[22] Final Draft Staff Report for Rule 12-16, available at http://www.baaqmd.gov/~/media/files/planning-and-research/rules-and-regs/workshops/2017/12-16-staff-report.pdf?la=en, at 38.

disparately severe impacts on vulnerable populations regionally and in communities on refinery fencelines.[23]

To the contrary, the Legislature has already made an explicit finding regarding this disproportionate impact of pollution. In 2006, the State enacted Assembly Bill No. 32 ("AB32") that recognized the "disproportionate impacts from substandard air quality in the form of higher rates of respiratory illness, hospitalizations, and premature death," and therefore directed public and private investment to these "most disadvantaged communities." In 2012, the State enacted Senate Bill No. 535, which sought to identify those communities. Thereafter, the California Environmental Protection Agency and the Office of Environmental Health Hazard Assessment developed a science-based tool for evaluating multiple pollutants and stressors in communities, called the California Communities Environmental Health Screening Tool (CalEnviroScreen).

More recently, California's adoption of Senate Bill No. 32 ("SB32") codifies ambitious climate change goals requiring the state to reduce greenhouse gas emissions to 40% below 1990 levels by 2030.[24] The passage of SB32 (and its ambitious greenhouse gas reduction targets) was contingent on the enactment of companion legislation — Assembly Bill No. 197 ("AB197").[25] AB197 was introduced to provide greater legislative oversight in developing and adopting methodologies to reduce climate change pollution. This is significant because AB197 calls for specific measures that make the Air District's[26] promulgation of refinery greenhouse gas caps an essential component to achieving the state's more aggressive climate change pollution targets.

Importantly, SB32 paired with AB197 calls for a marked change in how California will achieve its more ambitious climate change pollution reduction goals. SB32 and AB197 require that the state "achieve the more stringent GHG emission reductions in a manner that benefits the state's most disadvantaged communities and is transparent and accountable to the public and the Legislature."[27] AB197 requires regulators to consider and address climate change and related pollution impacts on California's disadvantaged communities by considering the social costs of greenhouse gas emissions and implementing equitable solutions to mitigate the problem.[28] For example, while some regions of the state can afford to put more Teslas on the road, other regions that are disproportionately burdened by greenhouse gas and toxic polluting industries cannot. AB197 addresses this problem head-on by requiring regulators to prioritize the implementation of regulations that result in <u>direct emissions reduction at large stationary sources</u> in order to protect the state's most impacted and disadvantaged communities.[29] In other words, the Legislature expressly conditioned passage of SB32 on adoption of companion legislation—AB 197—that favors "command-and-control"

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[23] *Id.* at 39.
[24] Senate Bill No. 32: Global Warming Solutions Act of 2006: emissions limit (extends AB 32 and sets 2030 greenhouse gas emissions targets), available at https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201520160SB32.
[25] SB32 specifies that "it shall become operative only if AB 197 is enacted…"
[26] Air districts have primary authority over regulation of stationary source air pollution.
[27] SB 32 Sec. 1 (d); *see also* AB 197 Sec. 1 (c), (e).
[28] AB 197 Sec. 5.
[29] *Id.*

regulation over market-based and incentive programs for large stationary sources like refineries when necessary to cause actual emission reductions in disadvantaged communities.[30] The bill's analysis even acknowledges that direct regulation is necessary in such communities and must be prioritized to achieve statewide limits while mechanisms such as cap-and-trade may operate as backstops to achieve excess reductions.[31]

In pertinent part, AB197 provides:

> [T]he state board shall … consider the social costs of the emissions of greenhouse gases, and prioritize both of the following:
>
> (a) *Emission reduction rules and regulations that result in direct emission reductions* at large stationary sources of greenhouse gas emissions sources and direct emission reductions from mobile sources.
>
> (b) *Emission reduction rules and regulations that result in direct emission reductions* from sources other than those specified in subdivision (a).

AB197 explicitly acknowledges the need to consider the social, health and economic costs on disadvantaged communities as the basis for compelling direct regulation of greenhouse gas and local pollution specifically within the refinery sector.

Clarifying the state's position, on April 5, 2017, the Air Resources Board ("ARB") sent a letter to the Air District regarding three rules under consideration: Rules 11-18, 12-16, and 13-1.[32] Echoing the language of AB197, ARB states that it:

> … support[s] the intent of [Rule 12-16] and agree more can and must be done to deliver real reductions in the pollutants that are impacting the health of residents living near refineries …

Finally, in September 2016, public health academics from UC Berkeley, USC, San Francisco State University and Occidental College produced the report, "A Preliminary Environmental Equity Assessment of California's Cap-and-Trade Program." The study assessed the inequities in the location of GHG-emitting facilities and in the amount of GHGs and PM_{10} emitted by facilities regulated under cap-and-trade, documented that local pollution from refineries has recently increased, and underscored the potential health benefits of direct greenhouse gas reduction regulation.[33]

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[30] AB197, Bill Analysis, Aug. 2016, available at http://www.leginfo.ca.gov/pub/15-16/bill/asm/ab_0151-0200/ab_197_cfa_20160824_113105_asm_floor.html.

[31] *Id.*

[32] ARB Letter to BAAQMD Re: Refinery Rules, April 5, 2017, attached as Attachment B.

[33] Cushing, L, Wander, M, Morello-Frosch, R, Pastor, M, Zhu, A, Sadd, J, "A Preliminary Environmental Equity Assessment of California's Cap-and-Trade Program," University of California, Berkeley, University of Southern California, San Francisco State University, Occidental College, Sept. 2016, available at http://cal.streetsblog.org/wp-content/uploads/sites/13/2016/09/Climate_Equity_Brief_CA_Cap_and_Trade_Sept2016_FINAL.pdf.

In stark contrast, the DEIR, in reliance on the Staff Report, remains largely silent and fails to describe the disproportionate and cumulative local impacts of refinery combustion emissions. Therefore, the commenters make the following recommendation:

Recommendation # 3: Revise sections of the Environmental Setting to include the Legislature's findings, publicly available data and studies detailing the existence of a disproportionate and cumulative impact of combustion pollution, in particular $PM_{2.5}$ *and ultra-fine PM emissions and exposures, surrounding Bay Area refineries.*

Moreover, the DEIR's description of the Existing Regulatory Setting omits any discussion of the above State legislation recognizing the disproportionate impact of pollution from refineries.[34] The Air Quality Existing Regulatory Setting must be substantially revised to include an adequate assessment of the local impacts of refinery pollution on vulnerable populations and nearby communities, and in particular, on low-income communities of color that have historically faced such a disproportionate burden.

The Air Quality Existing Regulatory Setting must also include a description of the State's current regulatory framework to reduce GHG emissions, in particular AB32, SB32, AB197 and its explicit directive to directly limit pollution from high-emitting stationary sources, and any anticipated or future actions by ARB. Only then can the DEIR adequately reflect ARB's finding that Emission Caps "could help ensure that [Bay Area refineries] do not add to the state's overall emissions of greenhouse gases and criteria or toxic pollutants."[35]

Furthermore, that discussion must also consider the cumulative impact of increased pollution on already vulnerable populations and overburdened communities. Additionally, in so doing, the current environmental setting should also include data and documented vulnerability factors for these communities from existing mapping tools, such as CalEnviroScreen version 2.0.

Therefore, the commenters make the following recommendation:

Recommendation # 4: Revise sections of the Existing Regulatory Setting to include a discussion of State climate and other relevant pollution reduction policies, and include relevant vulnerability factors to assess disadvantaged communities' cumulative exposure to pollution impacts on vulnerable populations exposed to refinery emissions regionally, and, specifically, those in communities near Bay Area refineries.

Similarly, the Air District must also discuss its own current regulatory framework and whether it results in disproportionate local impacts of air pollution that Emission Caps could prevent from worsening. For instance, several commenters on this rulemaking have mentioned a potential conflict between the federal Clean Air Act and Emission Caps. The DEIR must be revised to include those various provisions of federal, state and local measures, and assess any potential conflict with Emission Caps.

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[34] DEIR at 3.2-14

[35] ARB Letter to BAAQMD Re: Refinery Rules, April 5, 2017, attached as Attachment B.

Any such assessment should expressly conclude that there is no such conflict. It is well settled that the federal Clean Air Act sets a floor for emission standards,[36] and air districts may set stricter standards,[37] even when neither federal nor state agencies have acted,[38] and in particular, standards tailored to prevent pollution based on local circumstances.[39] Therefore the commenters make the following recommendation:

Recommendation # 5: Revise sections of the Existing Regulatory Setting to include a discussion of the current regulatory framework and how that framework neither expressly nor impliedly preempts, or otherwise conflicts with, adoption and implementation of Emission Caps.

C. The Draft EIR Environmental Setting Must Include Discussion of the Trend Toward Increased Exports from Bay Area Refineries

The DEIR includes an area of potential controversy: "concerns that refinery expansion projects and trends toward increased exports have not been included for discussion." The initial draft Staff Report had noted that, "the Air District does not have the authority to *directly* address concerns about … the final destination of refined products."[40] However, much like the Air District's inability to directly regulate hazards at refineries is balanced by its ability to address such concerns through regulating resulting episodic spikes in emissions,[41] the DEIR must also discuss recent increasing exports from Bay Area refineries in terms of the authority the Air District does have to regulate refinery pollution. These facts are directly relevant to and will inform any environmental and economic analysis of Rule 12-16.

Emission Caps would not significantly limit Bay Area refiners' production, which is known because they ran at full capacity while emitting below the Emission Caps.[42] Data also show that Bay Area refineries are producing more gasoline and diesel products than necessary to satisfy local demand, as well as an increasing trend to export such products to foreign countries.[43] Whether or not the Air District can directly regulate this practice that over-burdens low-income communities of color in our State, with no net benefit to the State, the Draft EIR must still discuss this increasing trend. Such a discussion is relevant to analysis of environmental impacts as well as any socio-economic analysis and must be included in the current environmental setting. Therefore, the commenters recommend the following:

Recommendation # 6: Revise sections of the Environmental Setting to disclose the increasing trend toward exporting more refined product produced at Bay Area refineries.

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[36] Cal. Health and Safety Code § 39002

[37] *Id.*

[38] *Ultramar, Inc. v. South Coast Air Quality Management Dist.* (1993) 17 Cal.App.4th 689.

[39] Cal. Health and Safety Code § 40727.2(h)

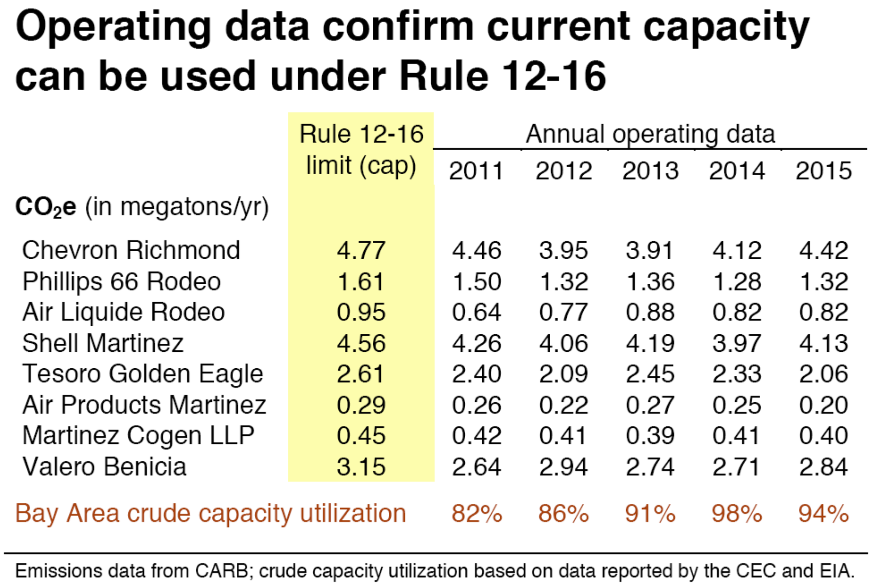
[40] Draft Staff Report at 39.

[41] *See supra,* BAAQMD Regulatory Concept Paper, October 2012.

[42] District staff admit this fact; see 30 January 2017 Stationary Source Committee video archive at 2:31:00 et seq.

[43] *See* prior comments submitted by CBE on 10/21/15, 11/23/15 and 6/10/16.

Moreover, the Staff Report asserts that adoption of Emission Caps may create similar economic impacts as the temporary closure of the ExxonMobil Torrance Refinery in 2015. In making this inaccurate determination, the Staff Report relies upon utilization data for PADD 5 refineries, which provide the average refinery operation utilization for *all West Coast refineries*, not just Bay Area refineries. By contrast, an analysis of Bay Area refineries alone[44] shows the following:



Operating data confirm current capacity can be used under Rule 12-16

CO_2e (in megatons/yr)	Rule 12-16 limit (cap)	Annual operating data 2011	2012	2013	2014	2015
Chevron Richmond	4.77	4.46	3.95	3.91	4.12	4.42
Phillips 66 Rodeo	1.61	1.50	1.32	1.36	1.28	1.32
Air Liquide Rodeo	0.95	0.64	0.77	0.88	0.82	0.82
Shell Martinez	4.56	4.26	4.06	4.19	3.97	4.13
Tesoro Golden Eagle	2.61	2.40	2.09	2.45	2.33	2.06
Air Products Martinez	0.29	0.26	0.22	0.27	0.25	0.20
Martinez Cogen LLP	0.45	0.42	0.41	0.39	0.41	0.40
Valero Benicia	3.15	2.64	2.94	2.74	2.71	2.84
Bay Area crude capacity utilization		82%	86%	91%	98%	94%

Emissions data from CARB; crude capacity utilization based on data reported by the CEC and EIA.

Rule 12-16 limits pollution based on 107% of the actual maximum emissions over these past five years. As 2014 saw 98% utilization, Emission Caps would allow the full use of current capacity.[45] Particularly noteworthy, the Bay Area refineries also operated within this capacity during the Torrance Refinery outage in 2015.

Similarly, the Staff Report has prematurely determined that Rule 12-16 may have significant economic impacts in the event that either refineries choose to make improvements and increase production above current capacity, or demand for gasoline or diesel products increases in California.[46] Those determinations, however, may be properly made only following an adequate description of the environmental setting as noted above. Therefore, the commenters recommend the following:

<u>Recommendation # 7</u>: revise the Environmental Setting and Staff Report using CEC data for Bay Area refineries alone, instead of PADD 5 West Coast refinery data, and disclose that Bay Area refineries emitted below the Emission Caps while operating at maximum capacity; and make subsequent revisions to all sections of the DEIR and Staff Report that rely upon PADD 5 West Coast refinery data instead of Bay Area refinery data alone.

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[44] Crude capacity utilization based on CEC and EIA data, as further detailed in Karras 2017.

[45] This *<u>annual average</u>* production rate approximately 97.7 % of maximum *<u>calendar-day</u>* capacity in 2014 indicates extremely high, and practically full, capacity utilization. Regardless, implementation of the 7% buffer under Emission Caps, when the highest year = 97.7% would still allow Bay Area refineries to operate at 100% utilization.

[46] Final Draft Staff Report at 29-30.

Finally, the DEIR's analysis is further flawed by assuming that Bay Area refineries would be forced to use pollution abatement techniques to comply with Emission Caps. The DEIR states, "installation of additional air pollution control equipment that *would be needed* to remain in compliance with the criteria pollutant emissions limits under Rule 12-16."[47]

Notably, there is another option: compliance with Rule 12-16 may be accomplished without any change to current equipment or operations, and without incurring any new cost, based on emissions over the most recent five years reported. This is particularly the case as Bay Area refineries are operating at practically full capacity.

Therefore, the commenters recommend the following:

Recommendation # 8: Revise the DEIR to disclose the no cost, no impact option of compliance with Rule 12-16 and remove all references to and analysis of the installation of pollution control equipment as a necessary compliance option for Rule 12-16, and also, any discussion of such associated significant impacts.

II. The DEIR's "No Project" Alternative Fails to Meet CEQA's Requirements.

The CEQA Guidelines have explicitly rejected the notion that the "no project" alternative may simply reflect current conditions as assessed in an EIR's environmental setting, or even maintenance of such status quo. Rather, CEQA Guidelines § 15126.6(e) provides that a "no project" alternative must address "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." The Guidelines also elaborate further on how the "no project" alternative should proceed in this specific instance:

> When the project is the revision of … a regulatory plan, policy or ongoing operation, the "no project" alternative will be the continuation of the existing plan, policy or operation into the future … the projected impacts of the proposed plan or alternative plans would be compared to the impacts that would occur under the existing plan.[48]

Therefore, a "no project" alternative must not only outline foreseeable changes to the environmental setting, but also evaluate how the Air District's current regulations, without Rule 12-16, could protect public health given those changes, particularly with regard to any disproportionate impact on low-income communities of color.

The DEIR includes Alternative 2.1, the "no project" alternative to Rule 12-16.[49] Alternative 2.1 fails to provide information necessary to determine the environmental and

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[47] DEIR at 4-13 (emphasis added).

[48] CEQA Guidelines § 15126.6(e)(3)(A).

[49] DEIR at 4-5.

public health impacts with and without Emission Caps. The No Project Alternative completely ignores the preventative nature of Rule 12-16, how it could prevent increasing emissions, and particularly with regard to the resultant local impacts on disadvantaged and disparately vulnerable communities. Instead, Alternative 2.1 claims that pollution from PM, NO_x and SO_2 will continue to be addressed by "a myriad [of] Air District efforts." The DEIR does admit: "While this collection of measures would serve to significantly reduce the emission of these pollutants, they cannot, however, guarantee that these emissions would not increase from these facilities due to production increases or modifications to operations." This cursory analysis fails to meet the requirements of CEQA Guidelines § 15126.6(e).

The analysis, moreover, is not only cursory but also incorrect. For example, the DEIR remarks that measures in the 2017 Clean Air Plan will help in meeting the objectives of Rule 12-16, whilst the Clean Air Plan *includes* measure SS11 – emission limits on GHGs, PM, NO_x and SO_2, the same Emission Caps. In addition, while the DEIR discusses state climate policy, in particular AB32 and SB32, it simply does so in regard to how those policies can meet the same goals as Rule 12-16 – not how those policies can be advanced or complemented by Rule 12-16.[50] This analysis is backwards. Instead, in line with ARB's recognition of how Emission Caps complement state air quality goals, the DEIR should analyze how the state may or may not meet those air pollution control goals with and without Rule 12-16.

Available information the DEIR fails to disclose or evaluate suggests Bay Area refinery combustion emissions could increase by 40–100 %, foreclosing other existing and planned measures' ability to cut emissions as much as feasible, likely foreclosing achievement of regional climate protection targets, and resulting in 800–3,000 premature deaths over 40 years and disparately severe increase in refinery fence line communities' mortality burden 8–12 times that regionally.[51] Therefore, the commenters recommend the following:

<u>Recommendation # 9</u>: *Revise the No Project Alternative for Rule 12-16 to include: an evaluation of the foreseeable climate and local pollution impacts that could result from the several Bay Area refinery expansion projects that enable the refining of lower quality oil feedstocks; how the Air District's regulations and the State's climate policies with and without Rule 12-16 can or cannot reduce such impacts; a discussion of whether the "infrastructure inertia" created by the commitment to major capital refinery investments in process changes could enable more refining of more climate-disrupting feedstocks for the foreseeable future; and an analysis of the subsequent opportunity cost of a sustainable energy future.*

Finally, by determining that Alternative 2.2, implementation of Rules 11-18 and 13-1, is "preferred" over Rule 12-16, the DEIR apparently creates a false choice between Rule 12-16 and Rules 11-18 and 13-1. How Rules 12-16 and 13-1 complement one

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[50] *Id.*

[51] *See* Karras 2017.

another is detailed further below. But Rule 11-18 and Rule 12-16 are also complementary and not duplicative or mutually exclusive. Rule 11-18 targets various toxic air contaminants; it does not target, as Rule 12-16 does, GHGs and PM. Nor does Rule 11-18 prevent increasing emissions during the many years before it contemplates actual implementation of emission controls; Rule 12-16 prevents such emissions. Moreover, the large number of sources potentially affected by Rule 11-18 stands in stark contrast to the few affected by Rule 12-16. Each rule considers a significantly different range and source of pollutants. In fact, CEQA requires that an alternative "feasibly accomplish most of the basic objectives" of the proposed project.[52] Aside from the clear public health benefits of both rules, it is hard to imagine a single basic objective common to both Rules 12-16 and 11-18. We have consistently requested Air District staff to sever environmental review of the two proposals, but at a minimum, consideration of one as a mutually exclusive alternative to the other simply does not make sense and violates CEQA. Therefore, the commenters recommend the following:

<u>Recommendation # 10</u>: Sever review of Rules 11-18 and 12-16 by moving the analysis of Rule 12-16 from this DEIR, and include a complete and accurate analysis of Rule 12-16 in the DEIR for Rule 13-1 in time for both Rules 12-16 and 13-1 to be considered for adoption by the Board of Directors in September 2017.

III. The DEIR Fails to Adequately Discuss the Environmentally Superior Alternative

The DEIR states that Alternative 2.2, implementation of Rules 11-18 and 13-1, is the environmentally superior alternative to implementation of Rule 12-16.[53] The DEIR arrives at this faulty conclusion by committing three errors: first, as noted above, the DEIR incorrectly assumes several significant impacts of implementation of Rule 12-16; second, the DEIR incorrectly or prematurely assumes that Rule 12-16 and Rule 13-1 offer the same degree of protection; and third, incorrectly assumes that these complementary measures are alternatives, as discussed below.

The DEIR inappropriately identifies several significant impacts resulting from the construction of pollution abatement equipment. This analysis, however, is predicated on the incorrect assumption that Bay Area refiners *must* install such equipment in order to comply with Emission Caps. As noted, this flawed analysis ignores the viable option for refiners to comply by not changing any operations – a no cost and no impact option. Therefore, the commenters make the following recommendation:

<u>Recommendation # 11</u>: (in conjunction with Recommendation # 8) Revise the DEIR's findings of significant impacts that arise from the construction and operation of pollution abatement equipment to comply with Rule 12-16 (in all areas, Air Quality, GHGs, Hazards and Hazardous Materials, Hydrology, Water Quality, and Utilities,) and revise each subsequent section of the DEIR that had relied on those misidentified significant impacts, including consideration and comparison of Alternatives.

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[52] CEQA Guidelines § 15126.6(c).
[53] DEIR at 4-16.

Furthermore, Rule 13-1 is still in development and it is premature to make findings in this DEIR regarding how effective implementation of any rule in conjunction with Rule 13-1 may prove. As currently drafted, the measure exempts refinery combustion emissions of particulate matter, nitrogen oxides, and sulfur dioxide from direct control and could potentially allow facility-wide refinery emissions of greenhouse gases to increase. Recently, community groups submitted comments on *draft* Rule 13-1, supporting its goal, but also requesting a revised version that could better meet the Rule's objectives. Those are the same objectives that the DEIR determines Rule 13-1 already meets.[54] Therefore, the commenters make the following recommendation:

Recommendation # 12: Remove all analysis and comparison with draft Rule 13-1, or, specify that Rule 13-1 is still in draft form and requires further development in order to meet its objectives.

Finally, Rule 12-16 caps emissions per year, and draft Rule 13-1 seeks to cap emissions per barrel of oil refined. The per-year caps prevent increased emissions at current or increased production, and (if revised and corrected) the per-barrel caps prevent excess emissions by ensuring emissions decline when fewer barrels of oil are refined. Thus, in concept, Rule 12-16 and Rule 13-1 can work together to protect public health and the climate better than either rule could alone. Moreover, although the DEIR does not disclose any of this information, ARB has stated that both Rules 12-16 and 13-1 could "ensure that [Bay Area refineries] do not add to the state's overall emissions of greenhouse gases and criteria or toxic pollutants."[55] It is therefore wholly possible that implementation of Rules 12-16 and 13-1 together is an environmentally superior alternative to implementation of any of the rules alone. As noted in our comments on draft Rule 13-1, this draft measure, with revisions that in any case are essential for it to meet its objectives, is complementary to Rule 12-16.[56] Therefore, the commenters make the following recommendation:

Recommendation # 13: (in conjunction with Recommendation # 12) Remove the analysis of 12-16 from this DEIR, and include a complete and accurate analysis of Rule 12-16 in the DEIR for Rule 13-1, including consideration of implementation of Rule 12-16 and Rule 13-1 together as the environmentally superior alternative, to be considered for adoption by the Board of Directors in September 2017.

IV. The DEIR's Project Description is Inadequate

Although the DEIR describes the objectives of Rule 12-16, its description of the Rule lacks any adequate discussion or description of how Rule 12-16 may meet those stated project objectives. What analysis the DEIR does provide rests solely on potential pollution abatement equipment construction and installation. Moreover, the DEIR's analysis of impacts from add-on controls to meet pollution control limits, which the

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[54] *Id.* at 4-16, 4-17.

[55] *See* ARB Letter to BAAQMD Re: Refinery Rules, April 5, 2017.

[56] *See* Communities Comment on Rule 13-1, April 21, 2017, attached as Attachment C.

DEIR asserts shall be met without Rule 12-16, evidently assumes increasing refinery emissions as a given. Ignoring increasing refinery emissions in all other contexts of the DEIR renders the project description unstable.

A. The DEIR Fails to Describe the Complementary Nature of Rule 12-16

By failing to adequately depict the existing environmental and regulatory setting, the DEIR is foreclosed from describing how Rule 12-16 may complement other pollution reduction measures, including meeting the state's greenhouse gas reduction goals. ARB has stated that Rule 12-16 could assist in meeting the state's overall pollution reduction targets. Similarly, as there are no meaningful facility-wide limits on Bay Area refinery pollution, the various Air District regulations requiring pollution reduction at refineries will meet their objectives[57] only in conjunction with what Rule 12-16 provides: preventing emissions from increasing. Indeed, Rule 12-16 is included in the Air District's 2017 Clean Air Plan, the blueprint for how those emission reductions may be realized. Therefore, the commenters make the following recommendation:

Recommendation # 14: Revise sections of the Project Description to detail how Emission Caps, or a refinery-wide emission limit on GHGs, PM, NO_x and SO_2, may complement the Air District's and the state's current and foreseeable air pollution reduction measures at Bay Area refineries.

Similarly, the Air District's recent EIR for its 2017 Clean Air Plan notes that Rule 12-16 (measure SS11 in the Clean Air Plan) does not have the potential to result in "leakage."[58] Leakage is "a reduction in emissions of greenhouse gases within the state that is offset by an increase in emissions of greenhouse gases outside the state."[59] Designed to prevent refinery emissions from increasing, Emission Caps set emission limits at levels that each Bay Area refinery already meets. As the Air District has previously stated that leakage is a concern for Rule 12-16, the DEIR must be corrected to explicitly dispel that incorrect notion. Therefore, the commenters recommend the following:

Recommendation # 15: Revise sections of the Project Description to clarify that implementation of Rule 12-16 will not result in leakage and otherwise complements the state's greenhouse gas reduction goals.

B. The DEIR Fails to Disclose that Compliance with Rule 12-16 Includes a No Cost and No Impact Option

The DEIR states:

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[57] *See* Resolution 2014-07; Attachment KR-4 to Karras, 2017 cited above (directing development of Rule 12-16 with other already-adopted refinery measures and including a goal for "as much emissions reductions as are feasible").

[58] 2017 Clean Air Plan EIR at 3.3-24.

[59] Cal. Health and Safety Code § 38505(j).

> Given that the emission limits [Emission Caps] are consistent with the current production capacity … affected facility operators may not be required to install control equipment if crude oil throughput and, therefore, fuel consumption do not substantially increase.

Yet, the DEIR also suggests that "to remain in compliance with draft Rule 12-16 the most likely means of reducing … emissions would be to further control emissions sources."[60] The DEIR consequently analyzes and associates significant impacts of construction and installation of pollution abatement technologies with implementation of Rule 12-16.

This error is, however, again predicated on the DEIR's reliance on the Staff Report's depiction of operational utilization of *all* West Coast refineries, and not only Bay Area refineries. Based on this faulty and overbroad range of data, the DEIR's analysis is incorrectly based on the assumption that Bay Area refineries are operating between 89.6 to 92.8 percent annual average utilization.[61] As noted above, had the DEIR used data for *only* Bay Area refineries, it would not have arrived at this conclusion as Bay Area refineries are currently operating at maximum capacity.

Moreover, the DEIR again ignores the no cost/no impact option of compliance where Bay Area refiners simply do not have to change operations based on 2010-2015 operations. Therefore, the commenters make the following recommendation.

<u>Recommendation # 16</u>: (in conjunction with Recommendation # 8) Revise sections of the Project Description to detail the no cost and no impact option of compliance with Rule 12-16.

C. DEIR Fails to Describe the Preventative Nature of Rule 12-16

The DEIR's Project Description describes the pollutants that Emission Caps would control,[62] but nowhere does it describe how these pollutants could foreseeably increase in the absence of Rule 12-16. For instance, in its discussion of GHG pollutant coverage, the DEIR fails to mention the correlation between increased GHG emissions and foreseeably increasingly dense oil feeds at Bay Area refineries. Nor does the DEIR disclose the increase in co-pollutant PM and PM precursor emissions that could result from greater use of combustion processes and subsequent increased combustion emissions, or likely increases in the frequency and magnitude of episodic emissions associated with refining lower quality oil.

Consequently, the Project Description fails to make clear the preventative nature of Emission Caps: to prevent these foreseeable emissions impacts, and in particular, impacts on vulnerable populations regionally, and in low-income communities of color in close proximity to refineries. Such a discussion must also identify how implementation

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[60] *Id.*
[61] Final Draft Staff Report at 31.
[62] DEIR at 2-10 through 2-11.

of Rule 12-16 could meet its project objective, specifically, by setting emission limits that effectively limit a switch to lower quality oil feeds, and discouraging investment in new refinery equipment that would allow for even greater refining of lower quality oils and lead to increased emissions of GHG, PM, NOx, or SOx from Bay Area refineries.[63]

Furthermore, the accompanying expert reports demonstrate that the potential emissions and associated health impacts and hazards Emission Caps could prevent can be estimated based on readily available information. As discussed at the outset of this comment, these reports estimate that Rule 12-16 could prevent refinery combustion emissions from increasing by 40–100%, and thereby avert 800–3,000 premature deaths from that pollution in the Bay Area over 40 years. Equally important, these reports estimate that preventing that oil quality-driven refinery emissions increase could avert a disparately severe mortality burden, 8–12 times the region wide burden from that emissions increase, in communities within 2.5 miles of refineries. The DEIR fails to include this crucial information.

Recommendation # 17: Revise sections of the Project Description to illustrate how Emission Caps can prevent locking in increased combustion emissions of GHGs, PM, NO_x *and* SO_2*, and provide an estimate of those emissions and resultant health risks and impacts that Emission Caps would prevent.*

V. The DEIR Fails to Adequately Analyze Economic Impacts

The DEIR fails to adequately analyze the economic impacts of implementation of Rule 12-16 in two distinct respects: first, it wrongly assumes Rule 12-16 would restrict current production capacity; and second, it incorrectly associates significant impacts of the construction and installation of pollution control equipment with implementation of Emission Caps, it incorporates a flawed, and unnecessary socio-economic analysis. While we recognize that CEQA does not require analysis of purely economic impacts, including an inaccurate assessment of economic impacts in the DEIR undermines CEQA's purposes, including by depriving decision-makers of the ability to balance any significant and unavoidable impacts of the project against its potentially overriding benefits.[64]

As noted above, Rule 12-16 would allow Bay Area refineries to operate at maximum current capacity. Emission Caps therefore could discourage any expansion of refinery operations, but would in no way affect current utilization. Moreover, there would be no need for any such expansion. In addition to the reasons noted above, the DEIR notes:

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[63] DEIR at 2-4; see also our prior comments illustrating the problem of "infrastructure inertia," Legal Analysis of the Bay Area Air Quality Management District's Authority to Adopt Emission Caps in Proposed Rule 12-16, July 14, 2016, attached as Attachment D.__

[64] *See* Pub. Res. Code 21081(a)(3).

> Presuming continuing increases in gasoline consumption results in unreasonable levels of speculation. For example, it is impossible for the Air District to predict the exact level of gasoline consumption in 2018 …[65]

This confirms that the DEIR's assumption such expansions are foreseeable itself rests on unwarranted speculation. Despite this inclusion in the DEIR, the accompanying Staff Report includes an economic analysis that is wholly dependent on such speculation that "demand for refined fuels continues to increase."[66] At the same time, the Staff Report acknowledges that "CARB projects that gasoline consumption will *decrease* over time due to stricter fuel consumption standards and other factors."[67] These contradictory statements in the DEIR and Staff Report present decision-makers and the public with confusing and inconsistent information. Therefore, the commenters provide the following recommendation:

Recommendation # 18: Revise sections of the Staff Report to remove any suggestion that gasoline demand or consumption in California will increase, and revise any sections of the Staff Report that mistakenly rely upon that speculative assumption.

Similarly, the DEIR's reliance on West Coast refinery utilization data (PADD 5) instead of only Bay Area refinery data, also plagues the Staff Report's economic and socio-economic analysis. In particular, Bay Area-specific refinery data show that in 2015 Bay Area refiners supplied the increased demand that resulted during the major gasoline-production shut-down at the southern California refinery in Torrance – and did so while still operating within capacity, at a Bay Area average crude capacity utilization of approximately 94 % - as would be the case with Emission Caps. Therefore, the commenters provide the following recommendation:

Recommendation # 19: Revise sections of the Staff Report to remove any suggestion that Emission Caps would cause similar gasoline price increases as occurred during the temporary shut-down of the southern California refinery in Torrance in 2015.

In addition, as compliance with Rule 12-16 may be accomplished by Bay Area refiners at no cost and with no environmental impact, inclusion of a socio-economic analysis related to Emission Caps is even unnecessary. The Staff Report's socioeconomic analysis is primarily concerned with the impacts of the option of compliance with Emission Caps by installing pollution control technology, which is not necessary to comply with the Rule. Moreover, pursuant to the CEQA Guidelines, evidence of social or economic impacts which do not contribute to or are not caused by physical impacts on the environment is not "substantial evidence" that would show those impacts to be significant.[68]

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[65] DEIR at 3.3-25.

[66] Final Staff Report at 32.

[67] *Id.*

[68] *See* CEQA Guidelines § 15131 and Public Resources Code § 21082.2(c).

As it is possible to comply with Rule 12-16 by maintaining current operations and at no cost and without any environmental impact, neither the DEIR nor the Staff Report should rely on speculative assertions that socioeconomic costs will be high, or will even occur at all. Therefore, the commenters make the following recommendation:

Recommendation # 20: revise sections of the Staff Report to correct the socioeconomic analysis and clarify the no cost and no impact compliance option for implementation of Rule 12-16.

VI. The DEIR Also Commits Procedural Violations of CEQA

A. The DEIR Fails to Include Comments on the NOP/IS Detailing and Documenting the Above Concerns

The DEIR's Appendix A should have included all comments received by the Air District regarding the Notice of Preparation and the Initial Study for the DEIR. However, Appendix A fails to include:

Ostro, B.; Kyle, A.D.; Broome, C.V.; Rudolph, L.; Heller, J.; Brunner, W.; Dervin, K.; Kirsch, J.I. and Kuiper, H., 2016. *Health and Safety Commentary Pertaining to Rule 12-16 and 11-18;* comment letter signed by nine public health and medical professionals and experts in support of Rule 12-16. Submitted to the Air District as a comment regarding the scope of the Draft Environmental Impact Report for proposed Regulation 12, Rule 16. December 2, 2016 ("Health Experts' December 2016 Comment on the DEIR Scope").

Karras, 2016. *Combustion Emissions from Refining Lower Quality Oil Part 2: How Much Could a Switch to 'Tar Sands' Oil Increase Direct Emissions of* $PM_{2.5}$ *and* CO_2 *from Northern California Oil Refineries?;* submitted to the Air District as a comment regarding the scope of the DEIR for proposed Regulation 12, Rule 16. December 2, 2016. ("CBE December 2016 Technical Report on the DEIR Scope").

Comments on the Scope and Content of the Notice of Preparation and Initial Study for Regulation 12: Miscellaneous Standards of Performance, Rule 16: Petroleum Refining Facility-Wide Emissions Limits (Rule 12-16); comments provided to the Air District by 350 Bay Area, Center for Biological Diversity, Communities for a Better Environment, Natural Resources Defense Council, and Sierra Club. December 2, 2016 ("December 2016 Legal Comment of 350 Bay Area, CBD, CBE, NRDC, and Sierra Club on the DEIR Scope").

These comments identified shortcomings that have been carried forward into the DEIR, particularly, its failure to adequately describe the existing environmental setting, the no project alternative, and the increased disproportionate impact of pollution on low-income communities of color that Emission Caps would prevent. Therefore, the commenters make the following recommendation:

Recommendation # 21: Revise Appendix A of the DEIR to include the "Health Experts' December 2016 Comment on the DEIR Scope," "CBE December 2016 Technical Report on the DEIR Scope," and "December 2016 Legal Comment of 350 Bay Area, CBD, CBE, NRDC, and Sierra Club on the DEIR Scope."

B. The DEIR Prejudices Consideration of Rule 12-16 by Mislabeling it "CBE's" Proposal

In 2012, the regulatory concept paper for this rulemaking found that a switch to lower quality grades of oil could increase refinery emissions significantly.[69] This demonstrated the need for a "backstop" to prevent increasing refinery emissions.[70] In 2014, the Air District resolved to develop Rule 12-16 for this purpose.[71]

The DEIR fails to disclose these facts regarding the Air District's role in the development of Rule 12-16, and instead states that Rule 12-16 reflects a "policy recommendation from CBE and their associated organizations,"[72] thereafter repeatedly referencing this Air District-proposed action as only recommended by "CBE." This error presents an incomplete, inaccurate, and biased description of Rule 12-16 that prejudices consideration of the need for Emission Caps, which the DEIR as noted above, fails to adequately discuss. The commenters therefore make the following recommendation:

Recommendation # 22: Revise all sections of the DEIR and Staff Report that refer to Rule 12-16 as merely "CBE and their associated organizations" or "CBE's" proposal and disclose the Air District's role in the development of Rule 12-16.

VII. CONCLUSION

For the foregoing reasons, the DEIR is inadequate under CEQA. We respectfully request the Air District Board to direct Staff to revise the DEIR in accordance with the above recommendations, and, to do so in time for consideration of Emission Caps and Rule 13-1 for adoption this September. Doing so would not only bring the DEIR into compliance with CEQA, but would also address the concerns of Air District Staff that this rulemaking may be arbitrary and capricious.[73]

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[69] Petroleum Refining Emissions Tracking, Regulatory Concept Paper, *available at* http://www.baaqmd.gov/~/media/files/planning-and-research/rules-and-regs/workshops/2013/1215_dr_rpt032113.pdf?la=en.

[70] *Id.*

[71] Air District Resolution 2014-07, adopted October 15, 2014.

[72] DEIR at 2-1

[73] See Final Draft Staff Report at 37-38.

Respectfully Submitted,

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Nancy Rieser
Crockett-Rodeo United to Defend the Environment

Steve Nadel and Shoshana Wechsler
Sunflower Alliance

Janet Johnson
Richmond Progressive Alliance

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ATTACHMENT A

Bay Area Air Quality Management District
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VIA EMAIL
vdouglas@baaqmd.gov
Victor Douglas

December 2, 2016

RE: Comments on the Scope and Content of the Notice of Preparation and Initial Study for Regulation 12: Miscellaneous Standards of Performance, Rule 16: Petroleum Refining Facility-Wide Emissions Limits (Rule 12-16)

Dear Mr. Douglas,

The Notice of Preparation and Initial Study for Rule 12-16[1] ("NOP/IS") suffer from significant defects and omissions in violation of the California Environmental Quality Act ("CEQA"). In particular, the NOP/IS omit critical discussion of recently permitted or reasonably foreseeable Bay Area refinery expansion projects that provide those refineries with the ability to process more polluting and climate disrupting oil feedstock. As such, the NOP/IS fail to adequately capture the existing environmental setting, tainting any evaluation of Rule 12-16. The NOP/IS reach several faulty conclusions, particularly regarding how adoption of Rule 12-16 (hereafter also referenced as "Emission Caps") might complement or conflict with the Bay Area Air Quality Management District's ("Air District") existing regulations and the State's climate policies, in particular, AB197.

At the November 16 meeting of the Air District Board of Directors, the Board of Directors provided specific direction to staff to include all relevant factual information for the determination of whether any such conflicts exist, within the Draft Environmental Impact Report

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[1] Including the accompanying October 2016 Draft Staff Report ("Staff Report") which discusses several issues required for inclusion in the Draft Environmental Impact Report, as detailed throughout this comment.

for Rule 12-16 (“Draft EIR”). Adhering to the Board’s direction may remedy any similar defects in the Draft EIR as detailed further below.

I. The Draft EIR Must Include Discussion of Potential Conflicts with State and Regional Plans and Policies

CEQA Guidelines §15125(d) provides that an EIR *shall* discuss any inconsistencies between the proposed project and applicable general plans and regional plans. The Guidelines specifically state that such regional plans include “the applicable air quality attainment or maintenance plan or State Implementation Plan.” We emphasize that the Draft EIR must include such a discussion which, following Board direction, requires disclosure and analysis of the following.

(i) Consistency with the Clean Air Act

The Air District is designated nonattainment for the 2006 $PM_{2.5}$ National Ambient Air Quality Standards (“NAAQS”). Recently, in August 2016, the Environmental Protection Agency (“EPA”) issued a final rule providing a limited approval and limited disapproval of revisions to Air District Regulation 2, Rules 1 and 2 (“2-1” and “2-2”).[2] The EPA concluded that Air District Rules 2-1 and 2-2 would become the federally enforceable New Source Review (“NSR”) program in the SIP for the Air District, subject to the Air District’s obligation to correct the rule deficiencies listed in the Federal Register.[3] Notably, the EPA found that the Air District’s NSR regulations did not meet federal standards: “emission reductions intended to be used as offsets for new major sources or major modifications are only creditable if they are reductions of actual emissions, not reductions in the [potential to emit] of a source.”[4] The federal provisions at issue include Clean Air Act §§ 173(a) and (c), the same provisions that the Staff Report suggests conflict with adoption of Rule 12-16.

Pursuant to the CEQA Guidelines, the Draft EIR must discuss any potential conflict. The Staff Report claims that there is a “significant argument” that Emission Caps would conflict with these federal provisions, but does not support that assertion with any facts or data.[5]

At a minimum, the Draft EIR must disclose relevant facts necessary for the Board and public to determine whether any such conflict exists. Such data must include: the amount of pollutant offsets, for PM_{10}, $PM_{2.5}$, SO_x and NO_x, that the Air District has allowed historically and foreseeably could allow in the future; whether any such offsets were granted subject to Rules 2-1 and 2-2 when those rules were applied less stringently than federal standards; and if so, whether Emission Caps may actually complement, rather than conflict with, achievement of the NAAQS. This discussion must also include a similar analysis of outstanding offsets held by refiners for previously permitted new or modified sources. Part II of this comment also details other relevant factual information required to make such an adequate determination regarding this alleged conflict.

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[2] Federal EPA docket number EPA-R09-OAR-2015-0280, available at https://www.regulations.gov/document?D=EPA-R09-OAR-2015-0280-0020

[3] *Id.*

[4] *Id.*

[5] Staff Report at 17.

(ii) Consistency with the State's Climate Policies

We are pleased that during the November 14 Scoping meeting, Air District staff clarified that the Draft EIR would discuss and evaluate any potential conflicts between Emission Caps and the State's Climate policies. Those policies include: AB32 and its successor legislation SB32 and AB197.

California's recent adoption of SB32 codifies ambitious climate change goals requiring the state to reduce greenhouse gas emissions to 40% below 1990 levels by 2030.[6] The passage of SB32 (and its ambitious greenhouse gas reduction targets) was contingent on the enactment of companion legislation — AB 197.[7] AB197 was introduced to provide greater legislative oversight in developing and adopting methodologies to reduce climate change pollution. This is significant because AB197 calls for specific measures that make the Air District's[8] promulgation of refinery greenhouse gas caps an essential component to achieving the state's more aggressive climate change pollution targets.

Importantly, SB32 paired with AB197 calls for a marked change in how California will achieve its more ambitious climate change pollution reduction goals. SB32 and AB197 require that the state "achieve the more stringent GHG emission reductions in a manner that benefits the state's most disadvantaged communities and is transparent and accountable to the public and the Legislature."[9] AB197 requires regulators to consider and address climate change and related pollution impacts on California's disadvantaged communities by considering the social costs of greenhouse gas emissions and implementing equitable solutions to mitigate the problem.[10] For example, while some regions of the state can afford to put more Teslas on the road, other regions that are disproportionately burdened by greenhouse gas and toxic polluting industries cannot. AB197 addresses this problem head-on by requiring regulators to prioritize the implementation of regulations that result in <u>direct emissions reduction at large stationary sources</u> in order to protect the state's most impacted and disadvantaged communities.[11] In other words, the Legislature expressly conditioned passage of SB32 on adoption of companion legislation—AB 197—that favors "command-and-control" regulation over market-based and incentive programs for large stationary sources like refineries when necessary to cause actual emission reductions in disadvantaged communities.[12] The bill's analysis even acknowledges that direct regulation is necessary in such communities and must be prioritized to achieve statewide limits while mechanisms such as cap-and-trade may operate as backstops to achieve excess reductions.[13]

The Staff Report conveys concerns that a greenhouse gas emission cap on refineries would conflict with California's greenhouse gas cap-and-trade and the Air District's own criteria

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[6] Senate Bill No. 32: Global Warming Solutions Act of 2006: emissions limit (extends AB 32 and sets 2030 greenhouse gas emissions targets), available at https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201520160SB32.

[7] SB32 specifies that "it shall become operative only if AB 197 is enacted…"

[8] Air districts have primary authority over regulation of stationary source air pollution.

[9] SB 32 Sec. 1 (d); *see also* AB 197 Sec. 1 (c), (e).

[10] AB 197 Sec. 5.

[11] *Id.*

[12] AB 197, Bill Analysis, Aug. 2016, available at http://www.leginfo.ca.gov/pub/15-16/bill/asm/ab_0151-0200/ab_197_cfa_20160824_113105_asm_floor.html.

[13] *Id.*

pollutant trading program. The report lacks any justification for this assertion. Also, the Staff Report states that the Board may not be able to justify the necessity of a greenhouse gas cap approach because other jurisdictions have not adopted one.[14] However, the Air District need not look to other jurisdictions for the authority to regulate greenhouse gas or other pollutant emissions.

The Staff Report also asserts that it would be difficult for the Air District to explain the benefit of capping greenhouse gas emissions because they are not localized health concerns.[15] However, data exists to the contrary. As one example, a recent University of Southern California study documents that local pollution from refineries has recently increased and underscores the potential health benefits of direct greenhouse gas reduction regulation.[16] The Staff's argument about localized health concerns is indeed a red herring. The momentum behind AB197's passage precisely counters this argument. AB197 explicitly acknowledges the need to consider the social, health and economic costs on disadvantaged communities as the basis for compelling direct regulation of greenhouse gas and local pollution specifically within the refinery sector.

The Staff Report is simply devoid of any discussion of the new regulatory landscape within which ARB and the Air District will be operating. It fails to mention SB32, AB197, its emphasis on equitable climate change solutions that protect California's disadvantaged communities, and its prioritization of direct emission reduction controls on the largest greenhouse gas polluting sources, in particular, the refinery sector.

Notwithstanding the Staff Report's omissions, the underlying purpose of AB197, that the state's climate change programs are not shared equally by all Californians, places an especially heavy burden on the Air District to address this problem. This is particularly true given that almost a third of the state's oil refineries are located in the Bay Area, and that the health and safety of Bay Area communities have long suffered disproportionately from the region's refinery pollution problems. Unfortunately, absent direct regulation of the refinery sector, the greenhouse gas and local pollution problems from refineries are only expected to worsen with the anticipated importation of more carbon intensive, low quality crudes such as Canadian tar sands.[17]

While ARB has primary authority over regulation of mobile sources of pollution, under the Federal Clean Air Act and state law, California's Air Districts have primary regulatory authority over stationary sources of air pollution.[18] Indeed, the enactment of SB32 and AB197 does not change this. Additionally, the courts have long affirmed air district authority to regulate

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[14] *Id.*at 17.

[15] *Id.* at 20.

[16] Cushing, L, Wander, M, Morello-Frosch, R, Pastor, M, Zhu, A, Sadd, J, "A Preliminary Environmental Equity Assessment of California's Cap-and-Trade Program," University of California, Berkeley, University of Southern California, San Francisco State University, Occidental College, Sept. 2016, available at http://cal.streetsblog.org/wp-content/uploads/sites/13/2016/09/Climate_Equity_Brief_CA_Cap_and_Trade_Sept2016_FINAL.pdf.

[17] "Next Frontier for Dangerous Tar Sands Cargo: California," Natural Resources Defense Council, Issue Brief, April 2015, at 2, available at https://www.nrdc.org/sites/default/files/west-coast-tar-sands-threat-ca-FS.pdf (tar sands process at California refineries could grow from 50,000 bpd to 650,000 bpd by 2040).

[18] *Ultramar, Inc. v. South Coast Air Quality Management Dist.* (1993) 17 Cal.App.4th 689, 708, citing *Western Oil & Gas Assn. v. Monterey Bay Unified Air Pollution Control Dist.* (1989) 49 Cal. 3d 408; *Orange County Air Pollution Control Dist. v. Public Util. Comm*. (1971) 4 Cal.3d 945, 948 (emphasis in original); Cal. Health and Safety Code § 40000.

air pollutants from large industrial stationary sources more stringently than the state and/or federal government, even pollutants not regulated by the state.[19]

CEQA requires the Draft EIR to evaluate Rule 12-16 in the context of SB32 and AB197, including how it complements these state policies and any potential inconsistencies. ARB will soon complete its Scoping Plan for implementation of SB32 targets, followed by promulgation of regulations to achieve those targets. As such, ARB's plan may be extremely relevant to the Draft EIR discussion. Moreover, that discussion must also include relevant factual information as discussed in the next section of this comment.

II. The Draft EIR Must Include Factual Information Relevant to Determine Potential Legal Conflicts

The following defects in the NOP/IS prejudice any adequate evaluation of Rule 12-16, particularly with regard to the potential conflicts noted above. Adherence to Board direction, and the CEQA Guidelines as noted below, could remedy these defects in the Draft EIR.

(i) The Draft EIR Must Include an Adequate Description of the Environmental Setting

CEQA Guidelines § 15125(c) provides that "[k]nowledge of the regional setting is critical to the assessment of environmental impacts [and] [s]pecial emphasis should be placed on environmental resources that are rare or unique to the region." The courts have affirmed this principle, holding that the absence of accurate and complete information regarding the project setting precludes the adequate investigation and discussion of the environmental impacts of the project.[20] The NOP/IS fail to outline the environmental setting in three significant respects: a current regional crude shift to a lower quality, and more polluting, oil feedstock; the disproportionate impact of such increased pollution on local low-income communities of color; and finally, how that impact is emphasized by the contrast of growing foreign exports of fuel and decreasing domestic consumption.

(a) The Draft EIR Must Include Recent and Proposed Bay Area Refinery Expansion Projects in its Discussion of the Environmental Setting

First, since at least 2012, the Air District has acknowledged the influx of lower quality oils into the Bay Area and admitted the occurrence of "increased emissions of air contaminants" and emission increases as a result of "accidents related to the increased corrosiveness of lower quality crudes."[21] The Air District has since permitted at least three refinery expansion projects that enable those refineries to process and refine lower quality crude oil feedstocks.[22] Other

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[19] *Western Oil & Gas Assn. v. Monterey Bay Unified Air Pollution Control Dist*. (1989) 49 Cal. 3d 408, 418; *Ultramar, Inc. v. South Coast Air Quality Management Dist*. (1993) 17 Cal.App.4th 689, 707.

[20] *San Joaquin Raptor/Wildlife Rescue Center v. County of Stanislaus* (1994) 27 Cal. App. 4th 713.

[21] BAAQMD Regulatory Concept Paper, Petroleum Refining Emissions Tracking Rule, Draft, October 15, 2012, citing The U.S. Oil Refining Industry: Background in Changing Markets and Fuel Policies" (Nov. 22, 2010), available at http://www.baaqmd.gov/~/media/files/planning-and-research/rules-and-regs/workshops/2013/1215_dr_rpt032113.pdf?la=en.

[22] In 2013, the Air District permitted the Kinder Morgan Richmond Terminal Crude by Rail Project; in 2014, the Chevron Richmond Refinery Modernization Project; in 2015, the Phillips 66 Rodeo Refinery Propane Recovery Project.

similar expansion projects in the Bay Area are currently proposed, such as the Nustar Shore Terminals LLC Selby Terminal Crude Oil Project.

Ample evidence[23] illustrates that these expansion projects allow each respective refinery to have the flexibility to refine a broader range of crude oil feedstocks. These are the very "update[s]" or "modif[ications]" the Staff Report notes are required to process "crude oil from different sources."[24] Those new and different sources include a greater quantity of cost-advantaged and extreme polluting and climate disrupting feedstocks, such as tar sands diluted bitumen.

Nevertheless, the NOP/IS diminish the impact of these refinery expansion projects throughout the Bay Area, making only brief and cursory references. To the contrary, pursuant to CEQA Guidelines § 15125(c), the Draft EIR description of the environmental setting must disclose each permitted, proposed, and foreseeable refinery infrastructure expansion—or "update"—and whether, and if so by how much, each expansion may allow the respective refinery to process a greater quantity of more climate disrupting and polluting crude oil feedstock.

(b) The Draft EIR Environmental Setting Must Include an Assessment of the Local and Disproportionate Impact of Refinery Pollution

As noted in the November 11, 2016 comment on the NOP/IS submitted by CBE and other organizations, there is abundant evidence that refinery emissions disproportionately impact nearby low-income communities of color. We have illustrated several examples, including elevated indoor $PM_{2.5}$ exposures in the homes of low-income residents of color in Richmond, increased exposure to ultra-fine PM from refinery sources, and elevated concentrations of emissions during episodic emissions from incidents such as the August 2012 Chevron Richmond Refinery fire.

The NOP/IS, however, suggests that there is no such local impact of refinery pollution. The Staff Report even suggests that $PM_{2.5}$ exposure is a regional, not a local, problem. The Staff Report arrives at its faulty conclusion by relying upon only regional, or ambient, air quality data. Indeed, the air monitors that account for such measurements are located in San Pablo, Concord, Vallejo, San Rafael, San Jose, East Oakland, Livermore, San Francisco, Napa and Gilroy—none of which are home to a Bay Area refinery. The Draft EIR must instead include an adequate assessment of the local impact of refinery pollution, and in particular, on low-income communities of color that have historically faced such a disproportionate burden.

In assessing this local impact, it is also imperative to consider the cumulative impact of increased pollution on these already overburdened communities. Additionally, in so doing, the current environmental setting should also include data and documented vulnerability factors for these communities from existing mapping tools, such as CalEnviroScreen version 2.0.

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[23] *See* prior comments submitted by CBE on 10/21/15, 11/23/15 and 6/10/16.
[24] Staff Report at 8.

(c) The Draft EIR Environmental Setting Must Include Discussion of the Trend Toward Increased Exports from Bay Area Refineries

The NOP/IS states that "the Air District does not have the authority to *directly* address concerns about … the final destination of refined products."[25] However, much like the Air District's inability to directly regulate hazards at refineries balanced by its ability to address such concerns through regulating resulting episodic spikes in emissions,[26] the Draft EIR must also discuss recent increasing exports from Bay Area refineries. These facts are directly relevant to and will inform any environmental and economic analysis of Rule 12-16.

As noted in our prior comments, adoption of Emission Caps would not significantly limit Bay Area refiners' production, which is currently at approximately 97.7% of capacity. Data also show that Bay Area refineries are producing more gasoline and diesel products than necessary to satisfy local demand, as well as an increasing trend to export such products to foreign countries.[27] Whether or not the Air District can directly regulate this practice that over-burdens low-income communities of color in our State, with no net benefit to the State, the Draft EIR must still discuss this increasing trend. Such a discussion is relevant to analysis of environmental impacts as well as any socio-economic analysis and must be included in the current environmental setting.

Moreover, the Staff Report asserts that adoption of Emission Caps may create similar economic impacts as the temporary closure of the ExxonMobil Torrance Refinery in 2015. The Staff Report does so without detailing any supporting data; instead, the Draft EIR must address the current production capacities of the Bay Area refineries in the environmental setting, the destination of those products, and whether such an assertion of similar economic impact is even plausible in the context of Rule 12-16. This disclosure is necessary to dispel any superficial arguments of "leakage," and for an evaluation of any perceived conflicts between Emission Caps and cap-and-trade and other related provisions of AB 32.

Similarly, the Staff Report has prematurely determined that Rule 12-16 may have significant economic impacts in the event that either refineries choose to make improvements and increase production above current capacity, or demand for gasoline or diesel products increases in California.[28] Those determinations, however, may be properly made only following an adequate description of the environmental setting as noted above.

Accordingly, the environmental setting must also note all measures that the Air District has already established to decrease refinery-wide pollution by approximately 15%. Specifically, the Draft EIR must address how refinery emissions may increase beyond the Emission Caps given that already-required 15% reduction, and under what current or future foreseeable refinery modification scenarios, such as a switch to a more polluting crude oil feedstock, Emission Caps could cause the need for expensive pollution control equipment.

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[25] Staff Report at 24 (emphasis added).

[26] *See supra*, BAAQMD Regulatory Concept Paper, October 2012.

[27] *See* prior comments submitted by CBE on 10/21/15, 11/23/15 and 6/10/16.

[28] Staff Report at 25.

(ii) The Draft EIR Must Include an Adequate Discussion of Foreseeable Changes to the Environmental Setting in its Discussion of the No Project Alternative

The CEQA Guidelines have explicitly rejected the notion that the ”no project” alternative may simply reflect current conditions as assessed in an EIR’s environmental setting, or even maintenance of such status quo. Rather, CEQA Guidelines § 15126.6(e) provides that a “no project” alternative must address “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.” Further, the Guidelines continue to elaborate upon how the “no project” alternative should proceed in this specific instance:

> When the project is the revision of … a regulatory plan, policy or ongoing operation, the “no project” alternative will be the continuation of the existing plan, policy or operation into the future … the projected impacts of the proposed plan or alternative plans would be compared to the impacts that would occur under the existing plan.[29]

Therefore, the Draft EIR “no project” alternative must not only outline foreseeable changes to the environmental setting, but also evaluate how the Air District’s current regulations, without Rule 12-16, could protect public health given those changes, particularly with regard to any disproportionate impact on low-income communities of color. This requires full disclosure and evaluation of the foreseeable climate and local pollution impacts that could result from the several Bay Area refinery expansion projects that enable the refining of lower quality oil feedstocks, and also, how the Air District’s regulations with and without Rule 12-16 can reduce such impacts. Necessarily, this also requires a discussion of the “infrastructure inertia” created by the commitment to major capital refinery investments in process changes to enable more refining of more climate-disrupting feedstocks for the foreseeable future. The “no project” alternative also should discuss potential conflicts between these projects and the State’s climate policies, including an analysis of the opportunity cost of a sustainable energy future.

Finally, the NOP/IS apparently creates a false choice between Rules 12-16 and 11-18. Whilst Rule 11-18 targets various toxic air contaminants, it does not target, as Rule 12-16 does, GHGs and $PM_{2.5}$. Moreover, the number of sources potentially affected by Rule 11-18 stands in stark contrast to the few affected by Rule 12-16. Each rule considers a significantly different range and source of pollutants. In fact, CEQA requires that an alternative “feasibly accomplish most of the basic objectives” of the proposed project.[30] Aside from the clear public health benefits of both rules, it is hard to imagine a single basic objective common to both Rules 12-16 and 11-18. We have consistently requested Air District staff to sever environmental review of the two proposals, but at a minimum, consideration of one as an alternative to the other simply does not make sense and violates CEQA.

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[29] CEQA Guidelines § 15126.6(e)(2)(3)(A).
[30] CEQA Guidelines § 15126.6(c).

III. Conclusion

The NOP/IS mischaracterize or omit information relevant to the determination of how Rule 12-16 complements the requirements of the Clean Air Act and the State's climate policies. Adherence to the Air District Board's November 16 direction, and the CEQA Guidelines as noted above, may remedy these errors in the Draft EIR for Rule 12-16.

Respectfully Submitted,

Devorah Ancel
Staff Attorney, Sierra Club

Kevin Bundy
Senior Attorney and Climate Legal Director, Center for Biological Diversity

Laurence G. Chaset
Attorney at Law, Sustainable Energy Futures on behalf of 350 Bay Area

Roger Lin
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Comment also supported by:

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350 East Bay

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Sierra Club Bay Chapter

ATTACHMENT B

Air Resources Board

Mary D. Nichols, Chair
1001 I Street • P.O. Box 2815
Sacramento, California 95812 • www.arb.ca.gov

Matthew Rodriquez
Secretary for
Environmental Protection

Edmund G. Brown Jr.
Governor

April 5, 2017

Mr. Jack Broadbent
Executive Officer
Bay Area Air Quality Management District
375 Beale Street, Suite 600
San Francisco, California 94105

Dear Mr. Broadbent:

We understand the Bay Area Air Quality Management District is considering three new rules to address air pollution from refineries and other industrial facilities. I am writing to assure you that we support the intent of these rules and agree more can and must be done to deliver real reductions in the pollutants that are impacting the health of residents living near refineries and other large industrial facilities. We view the draft rules as an important first step in that direction. Indeed, as you may be aware, the California Air Resources Board (ARB) also is developing additional statewide regulations on these matters. This letter provides our brief comments on the proposed rules and discusses how the District, the California Air Pollution Control Officers' Association, and the ARB can work together to implement a comprehensive solution.

ARB staff strongly supports District action to develop, adopt, and enforce more stringent rules to reduce the health risk from stationary sources of air toxics, especially in impacted communities that are more vulnerable due to existing pollution burdens and socioeconomic conditions. The District staff's Draft Regulation 11, Rule 18 would require facility-by-facility risk assessment and emission reductions to get each facility below a cancer risk of 10 chances in a million, as achievable with toxics best available retrofit control technology. Based on ARB staff's preliminary analysis, we believe the approach described in the draft rule would be an effective mechanism to cut stack and fugitive emissions at refineries and other facilities. Moreover, your actions complement efforts by ARB to develop tighter regulations for trucks and ships at berth to further reduce emissions of toxic diesel particulate matter and other pollutants from both marine tankers delivering crude oil to refineries and trucks carrying gasoline and diesel fuel to market.

To augment the proposed air toxics rule, we encourage the District to continue investing in air monitoring enhancements (like remote sensing) and improving its emission inventories, which are critical given recent studies suggesting that fugitive emissions from refineries (and other sources) may be greater than current measurements indicate. ARB staff advocates aggressive enforcement at refineries and all stationary sources in the District. These efforts can help address toxic exposures, odors, and other community concerns. Your continued coordination with State and local authorities in targeted enforcement initiatives is essential to lessen the pollution burden in disadvantaged communities.

With regard to the District's draft Regulation 12, Rule 16, limiting emissions increases from refineries, and the new concept in Regulation 13, Rule 1, establishing a carbon intensity cap for refineries, we agree that both the approaches could help to ensure that these sources do not add to the state's overall emissions of greenhouse gases and criteria or toxic pollutants. Moreover, ARB is currently considering what actions might be taken to achieve additional reductions in toxic and criteria pollutants from refineries and we have identified that further action is needed throughout the state to expand public health protection for impacted communities. We would appreciate the opportunity to work with you and other affected air districts to develop complementary rules that can achieve the results that we and the communities want and expect.

To this end, we recommend establishing an industrial source action committee within the California Air Pollution Control Officers' Association, with an initial focus on refineries. The committee would be tasked with performing a rigorous engineering evaluation to identify measures to further cut emissions of all air pollutants from refineries, as well as coordinating and facilitating the implementation of such measures. You have my commitment that this effort will be a high priority for ARB staff.

Thank you for your consideration of the comments and issues raised here. If you have any questions or wish to discuss this letter, please contact me at (916) 322-7077.

Sincerely,

Richard W. Corey
Executive Officer

cc: See next page.

cc: Matt Rodriquez
Secretary for Environmental Protection
California Environmental Protection Agency
1001 I Street
Sacramento, California 95814

Honorable Liz Kniss, Chair
Bay Area Air Quality Management District
Board of Directors
375 Beale Street, Suite 600
San Francisco, California 94105

W. James Wagoner, President
California Air Pollution Control
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1107 9th Street
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Honorable Board Members
California Air Resources Board

California Environmental Justice Advisory
Committee Members
California Air Resources Board

bcc: (via email)

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Alan Abbs, CAPCOA

Greg Karras, CBE
Kathryn Phillips, Sierra Club

ATTACHMENT C

Communities for a Better Environment

APEN
Asian Pacific Environmental Network

Sunflower Alliance
Resisting fossil fuels. Working for climate justice.

RPA
Richmond Progressive Alliance

350 Bay Area

Interfaith Climate Action Network
Contra Costa County

21 April 2017

Jack Broadbent, Air Pollution Control Officer
Bay Area Air Quality Management District
375 Beale Street, Suite 600
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Via electronic mail to:

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Re: **Comment on Draft Rule 13-1, Refinery-level Emission Intensity Limits**

Dear Mr. Broadbent,

Draft Rule 13-1 seeks to address energy-related (combustion) emissions from oil refining by setting facility-specific limits on emissions per barrel of oil refined, also known as refinery "emission intensity." By this letter we respectfully provide comments and recommendations on this Draft Rule (DR).

Five major oil refineries collectively emit more GHGs and more particulate matter ($PM_{2.5}$) than any other industrial sector in your jurisdiction. $PM_{2.5}$ kills an estimated 2,000–3,000 Bay Area residents annually,[1] and GHGs threaten catastrophic climate disruption. Industry plans to refine lower quality oil, which requires burning more fuel for process energy, threaten to increase region-wide refinery emission intensity for these and other combustion pollutants by as much as 40–100 %.[2] By contrast, the DR's energy efficiency measures shave only 0.03–3.6 % from the refiners' current emission intensity (emissions per barrel oil refined).[3] Thus, the crucial goal of Rule 13-1, as the Air District staff states it in the Concept Paper,[4] is to "[e]nsure refinery combustion emissions do not increase on a per-barrel basis."

We strongly support the goal of ensuring that refinery emission intensity does not increase, however, serious errors and omissions in the proposed DR must be corrected in a revised version of Rule 13-1 before this measure could achieve that goal, as discussed in our comments and recommendations below.

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[1] BAAQMD *Clean Air Plan 2017* (see pp. C/5–C/7); and BAAQMD *Update on Regulation 6: Particulate Matter Rule Update, Stationary Source Committee;* 17 April 2017 (see Slide 4).

[2] See 2 December 2016 CBE Technical Report to BAAQMD on the Draft EIR Scope for proposed Rule 12-16.

[3] BAAQMD Staff Draft Rule 13-1 Workshop Report Emissions Limits Methodology.

[4] BAAQMD *Concept Paper – Rule 13-1: Refinery Carbon Intensity Cap;* updated 23 January 2017.

1. Revise the DR to directly control climate- <u>and</u> health-threatening emissions.

The DR exempts refinery combustion emissions of health-threatening air pollutants from direct control under Rule 13-1 by excluding $PM_{2.5}$, PM_{10}, NOx, and SO_2 from its limits. This is inconsistent with the District's stated purpose to control these refinery combustion emissions as well as GHGs,[4] unnecessary because available data support performance-based limits on each of these pollutants,[5] and inappropriate because it serves to perpetuate environmental <u>in</u>justice. We recommend that the DR be revised to include emissions per barrel limits on $PM_{2.5}$, PM_{10}, NOx, SO_2, and GHGs (CO_2e).

2. Reject the exemption from emission intensity limits at reduced refinery production rates that is proposed in the DR.

Preventing emissions caused by increased refinery emissions intensity (emissions per barrel oil refined) when a refinery reduces production (refines fewer barrels of oil) is the uniquely important purpose of proposed Rule 13-1. Other existing and planned measures will prevent emissions from increased refinery emission intensity at current production (mass emission caps Rule 12-16), and could reduce emissions through engineered controls and through reducing oil use, thereby reducing refinery production—***provided that Rule 13-1 is effective.*** Indeed, the State has endorsed this combination of measures that would work together to cap and cut emissions, including rules 13-1 and 12-16, along with other regional and statewide health and climate protections, in a recent letter supporting these complementary measures.[6]

But as proposed, Rule 13-1 would not be effective. The DR proposes to exempt refiners from emission intensity (emission/barrel) limits whenever they reduce production (the number of barrels refined). This proposed new policy to allow emissions would conflict with the purpose of this rule and with regional and state policies and plans. We object to this proposed allowance and request that the DR be revised to remove this exemption.

3. Revise the DR to include publicly verifiable refinery emission intensity limits.

Incredibly, the DR includes no numeric limits whatsoever, instead proposing to keep any actual emission limits that District staff might develop, monitor, enforce or revise under Rule 13-1 secret and publicly unverifiable. Both before and after public review and adoption of the rule, the DR proposes to base these limits on secret data for the amounts ("barrels") of oil refined—essential emissions data for this and any per-barrel emissions protection. This giveaway of public health protection oversight to secret pollution allowances, negotiated with polluters out of the public's view, appears absurd on its face. Here, where the oil industry already proved its ability to "game" air permitting based on confidential data, as shown by CEQA rulings in the courts,[7] gaining allowances to emit at a region-wide carbon intensity that already exceeds the nationwide average refinery carbon intensity,[2, 8] the fallacy and failure of such "secret limits" is manifest.

We strongly object to this proposal for secret refinery emission allowances.

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[5] <u>*See*</u> tables 12-16-301 through 12-16-305, Revised Proposed Rule 12-16 (March 2016).

[6] 5 April 2017 Letter from Richard Corey, California Air Resources Board, to Jack Broadbent, BAAQMD.

[7] <u>*See*</u> *CBE v. City of Richmond* 184 Cal_Ap. 4th.

[8] Karras, 2010. Combustion Emissions from Refining Lower Quality Oil: What Is the Global Warming Potential? *Environmental Science & Technology* **44:** 9584–9589. DOI: 10.1021/es1019965.

Moreover, the excuse for this inappropriate secrecy—the claim that historic long-term average refinery oil feed rates are trade secrets—is itself based on a falsehood. These data are not secrets: these data are reported publicly.

For example, actual refinery process rates for atmospheric crude oil distillation and oil feedstock conversion (cracking and coking), the relevant "barrels" data for facility level per-barrel caps on combustion emissions from the Bay Area refineries, are reported publicly in Clean Water Act discharge permit reviews.[9] See Table 1.

Table 1. Actual refinery oil feed rates reported publicly in Clean Water Act permits

	Crude feed rate (barrels/day)	Conversion feed rate (barrels/day)	Total of feed rates (barrels/day)
Chevron Richmond refinery	244,600	190,900	435,500
Phillips 66 Rodeo refinery	84,020	90,300	174,320
Shell Martinez refinery	149,200	144,300	293,500
Tesoro Golden Eagle refinery	143,600	139,800	283,400
Valero Benicia refinery	140,100	131,500	271,600

Maximum 12-month average atmospheric crude distillation rates and conversion (coking, catalytic cracking and hydrocracking) oil feed rates in the most recent 5 years reported, from Attachment F-1 of Clean Water Act NPDES permits.[9]

These data,[9] along with publicly verified refinery mass emission rates the Air District reported recently,[5] support the performance-based emission intensity limits shown in Table 2.
We recommend that, unless and until the Air District discloses additional data and shows that those additional data support more accurate publicly verifiable emission intensity caps, the DR should be revised to include these limits.

Table 2. Proposed performance-based oil refinery emission intensity limits (emissions per barrel oil fed to crude and conversion processing)

Emissions per barrel (b)	CO$_2$e (kg/b)	PM$_{2.5}$ (grams/b)	PM$_{10}$ (grams/b)	NOx (grams/b)	SO$_2$ (grams/b)
Chevron Richmond refinery	28.1	2.68	2.80	5.18	2.10
Phillips 66 Rodeo refinery	37.5	1.21	1.34	4.03	5.24
Shell Martinez refinery	39.8	3.92	4.66	8.45	11.5
Tesoro Golden Eagle refinery	30.3	0.87	1.03	9.37	5.30
Valero Benicia refinery	29.7	1.13	1.14	11.1	0.60

Based on maximum annual emissions in the most recent 5 years reported, from Proposed Rule 12-16[5] divided by maximum 12-month average total of oil feed rates to crude distillation and conversion units in the most recent 5 years reported, from Clean Water Act permits (see Table 1).[9] Support facilities included: Air Liquide included in Phillips 66 emissions; Air Products and Martinez Cogen included in Tesoro emissions.

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[9] See CBE, 2017. *Report on Data for Oil Feed Rates and Capacities of Refineries in the Jurisdiction of the Air District That Have Been Reported Publicly by Other Government Agencies;* technical report provided to the BAAQMD at its request on 28 February 2017.

4. Revise the DR to better limit combustion emission intensity and protect local refinery workers' jobs by excluding gasoline blending components and naphtha from refinery emission intensity limits.

The DR erroneously includes gasoline blending components and naphtha—oils that may require little more than blending into the gasoline pool at the refinery upon delivery from an outside source—in its calculation of refinery combustion emission intensity limits. These very light oils require much less energy for processing than the conversion of crude and its denser components to engine fuels. By weighting barrels of these inputs equally with barrels of crude and gas oil processed, the DR's approach commits an error.

Gasoline blending component imports from foreign sources account for only a small fraction (0–0.7 %) of total Bay Area refinery oil inputs now,[9] but such imports grow along with refiners' incentives to receive them. Importing them in much larger amounts after the DR's proposed approach (which includes these gasoline blendstocks in the "barrels" of its emissions-per-barrel limit compliance calculation) is implemented would artifically lower the emissions reported per barrel of total included oil input.

Failure to correct this error in the DR would encourage refiners to consider new oil feed blends that include larger volumes of cheaper, higher-emitting grades of crude oil along with larger volumes of imported gasoline blendstocks that would allow them to skirt the intent of Rule 13-1 by reporting artificially low emissions per barrel.

Thus, this error in the DR risks at least two unintended negative consequences. First, it risks failure to detect and limit an increase in the emission intensity of crude oil refining in the event that refiners increase in-plant finishing of gasoline-like imports. Second, because the same loophole encourages refiners here to import essentially finished gasoline that otherwise might be produced from relatively lower-emitting crude feeds here, this error in the DR might put refinery jobs here at risk unnecessarily. Therefore, we recommend that the DR be revised to exclude gasoline blending components and naphtha from its per-barrel emission intensity limits.

5. Emission intensity caps and mass emission caps are complementary measures.

Air District staff has asserted that proposed Rule 13-1 and proposed Rule 12-16 are "either-or" alternatives. This staff assertion is not accurate. As stated, per-barrel emission caps function differently from per-year emission caps; each type of cap can provide emission control benefits that the other cannot provide by itself, and both can work together to more effectively protect our health and climate. This District staff assertion also appears to be contradicted by the State's recent letter[6] supporting both Rule 12-16 and Rule 13-1 as measures that can and should work together with other District and State measures to better protect our health and climate.

Accordingly, we request that the Air District provide a corrected and complete analysis in support of revised Rule 13-1 as a necessary complement to Rule 12-16 and other federal, state and local health and climate protection measures, plans and policies.

Conclusion

We strongly support the goal of ensuring that oil refinery emissions intensity will not increase, and urge you to consider acting on our recommendations for correcting serious errors and omissions in proposed Draft Rule 13-1 discussed in these comments, so that this needed health and climate protection measure can achieve that crucial goal.

Respectfully,

Greg Karras, Senior Scientist
Communities for a Better Environment (CBE)

Miya Yoshitani, Executive Director
Asian Pacific Environmental Network (APEN)

Steve Nadel and Charles Davidson
Sunflower Alliance

Richard Gray
350 Bay Area

Janet Scoll Johnson
Richmond Progressive Alliance (RPA)

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Nancy Rieser
Crockett-Rodeo United to Defend the Environment (C.R.U.D.E.)

Katherine Black
Benicians for a Safe and Healthy Community (BSHC)

Kathy Kerridge
Good Neighbor Steering Committee of Benicia

Diane Bailey
Bay Area Environmental Advocate

Denny Larson, Executive Director
Community Science Institute

Bob Harlow
Mill Valley Community Action Network, and
United Marin Rising

Luis Amezcua
Sierra Club

Copy: Interested organizations and individuals

ATTACHMENT D

SIERRA CLUB
FOUNDED 1892

350 Bay Area

COMMUNITIES FOR A
BETTER
ENVIRONMENT

Bay Area Air Quality Management District
375 Beale Street, Suite 600
San Francisco CA 94105

<u>VIA EMAIL</u>
mhiratzka@baaqmd.gov
Marcy Hiratzka
Clerk of the Board

July 14, 2016

RE: Legal Analysis of the Bay Area Air Quality Management District's Authority to Adopt Petroleum Refining Facility "Emission Caps" in Proposed Rule 12-16

Chair Mar and Members of the Board:

Since at least 2012, the Bay Area Air Quality Management District ("Air District") has acknowledged the influx of lower quality oils into the Bay Area and admitted the occurrence of "increased emissions of air contaminants" and emission increases as a result of "accidents related to the increased corrosiveness of lower quality crudes."[1]

Air District staff have noted that "processing lower quality crudes also requires more intense processing and higher energy requirements," resulting in increased emissions of greenhouse gases ("GHG") and GHG co-pollutants.[2] The Air District's Emissions Tracking Rule, Regulation 12, Rule 15 ("Rule 12-15") was intended to include a mechanism to address these increasing emissions. During the development of Rule 12-15, industry commenters questioned the Air District's authority to adopt a regulation to mitigate health and safety risks posed by the refining of lower quality oils. The Air District then deferred further consideration of mitigating increasing emissions to proposed Regulation 12, Rule 16 ("Rule 12-16").

This has resulted in unreasonable regulatory delay in the adoption of such essential mitigation and preventative measures. In the interim, the Air District has permitted at least three refinery expansion projects that enable those refineries to process and refine lower quality crude oil feedstocks, the same "processing upgrades" the Air District acknowledged in 2012, and with no preventative backstop in place to address that increasing air pollution.[3] The proposal offered by several community, academic, public health and worker groups to adopt enforceable numeric emission limits at refineries ("Emission Caps") is such a backstop.

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[1] BAAQMD Regulatory Concept Paper, Petroleum Refining Emissions Tracking Rule, Draft, October 15, 2012, citing The U.S. Oil Refining Industry: Background in Changing Markets and Fuel Policies" (Nov. 22, 2010), available at http://www.baaqmd.gov/~/media/files/planning-and-research/rules-and-regs/workshops/2013/1215_dr_rpt032113.pdf?la=en.

[2] *Id.*

[3] In 2013, the Air District permitted the Kinder Morgan Richmond Terminal Crude by Rail Project; in 2014, the Chevron Richmond Refinery Modernization Project; in 2015, the Phillips 66 Rodeo Refinery Propane Recovery Project.

In order to expedite the rulemaking process and adequately address the increasing influx of lower quality oil into the Bay Area, Communities for a Better Environment ("CBE"), 350 Bay Area and Sierra Club submit the following comments regarding the Air District's authority to adopt Emission Caps. These comments detail why the Emission Caps are authorized by law and are needed now.

Comments Summary:

I. The Air District has broad authority to adopt Emission Caps. Specifically:

- Adoption of Emission Caps is consistent with the California Health and Safety Code,
- Adoption of Emission Caps complements and furthers the goals of AB 32, and
- Adoption of Emission Caps would not constitute "takings."

II. The California Environmental Quality Act ("CEQA") provides the proper procedural avenue to develop or clarify necessary findings.

III. Emission Caps are necessary now because:

- Lower quality oils are replacing traditional California sourced oil,
- Refining lower quality oils increases air pollution, and
- An Emissions Cap prevents those increases in air pollution.

I. The Air District Has Broad Authority to Adopt Emission Caps

California courts have consistently recognized air districts' "broad authority" to regulate emissions from stationary sources.[4] "The air pollution control district is *the* agency charged with enforcing both statewide and direct emission controls.[5] The legislature has made it clear that "local and regional authorities have the *primary* responsibility for control of air pollution from all sources other than emissions from motor vehicles."[6]

Air District regulations must, however, meet certain criteria, including those detailed in California's Health and Safety Code, harmonize with other California climate laws, such as AB 32, and constitute a valid exercise of police power. Adoption of Emission Caps meets these requirements as detailed below.

A. Adoption of Emission Caps Is Consistent with the California Health and Safety Code

Contrary to various industry comments, the California Health and Safety Code does not limit an Air District's role to simply implementing state and federal regulations. In fact, the Health and Safety Code explicitly states the opposite: "[Air] districts . . . determine the form,

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[4] Ultramar, Inc. v. South Coast Air Quality Management Dist. (1993) 17 Cal.App.4th 689, 708, citing Western Oil & Gas Assn. v. Monterey Bay Unified Air Pollution Control Dist. (1989) 49 Cal. 3d 408.

[5] Orange County Air Pollution Control Dist. v. Public Util. Comm. (1971) 4 Cal.3d 945, 948 (emphasis in orginal).

[6] Cal. Health and Safety Code § 40000.

content, and stringency of their rules and regulations."[7] It is "the intent of the Legislature that the districts retain their existing authority and flexibility to tailor their air pollution emission control requirements to local circumstances."[8]

Also, section 40001(a) provides that:

> "the [Air] districts shall adopt and enforce rules and regulations to achieve and maintain the state and federal ambient air quality standards in all areas affected by emission sources under their jurisdiction, *and* shall enforce all applicable provisions of state and federal law." (emphasis added)

The legislature's inclusion of the latter clause emphasizes that Air Districts do not simply have to maintain state and federal air quality standards; they may enact stricter rules. The courts have been in firm agreement. An air district's broad authority was most succinctly and accurately described in an early court opinion addressing this issue: "[to] protect the purity of the air."[9] This is consistent with the Air District's stated mission: "[t]he Air District aims to create a healthy breathing environment for every Bay Area resident while protecting and improving public health, air quality, and the global climate."[10]

In one case challenging this broad authority, the Monterey Bay Unified Air Pollution Control District proposed Rule 1000, designating certain substances as a "toxic" or "carcinogenic" air contaminant.[11] The Western Oil & Gas Association challenged this rule and argued that local districts could not regulate a substance until the Air Resources Board had designated that substance as a pollutant. Noting that the "districts' primary authority has been well understood," the court held that air districts may more stringently regulate pollutants, even pollutants not considered by the state.[12]

Another case squarely addresses this issue. In 1991, the South Coast Air Quality Management District proposed to adopt a rule banning the use and storage of hydrogen fluoride ("HF"), a feedstock used as a catalyst in the production of gasoline, at oil refineries.[13] Ultramar, a refining company, sued, contending that air districts' regulatory powers were limited to the "achievement of state and federal ambient air quality standards" only, and any further regulation was beyond delegated authority.[14] The Court of Appeal disagreed, emphasizing also that air districts possess inherent power to address both the abatement *and* prevention of air pollution episodes, whether or not regulated so by the state or federal regulations.[15]

Moreover, Health and Safety Code §40001(b) enables the Air District to prevent or abate "air pollution episodes which . . . cause discomfort or health risks to, or damage to the property

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[7] Cal. Health and Safety Code § 40727.2(h).
[8] *Id.*
[9] Milton H. Lees v. Bay Area Air Pollution Control Dist. (1965) 238 Cal.App.2d 850, 857.
[10] BAAQMD Mission Statement, available at http://www.baaqmd.gov/about-the-air-district/mission-statement.
[11] Western Oil & Gas Assn. v. Monterey Bay Unified Air Pollution Control Dist. (1989) 49 Cal. 3d 408.
[12] *Id.* at 418.
[13] Ultramar, Inc. v. South Coast Air Quality Management Dist. (1993) 17 Cal.App.4th 689.
[14] *Id.* at 707.
[15] *Id.*

of, a significant number of persons or class of persons."[16] This is relevant in three distinct respects, calling for swift adoption of the proposed Emission Caps: first, as noted immediately below, Particulate Matter ("PM") has been determined by the Air District to be a cause of premature death in the Bay Area; second, the Air District has the authority and obligation to prevent catastrophic episodic emissions, such as the August 2012 Chevron Richmond Refinery fire; and third, to also prevent potentially significant climate disrupting pollution. The Legislature has explicitly documented the consequences of climate change and increased GHG pollution, finding that it poses a threat to "public health" and will cause a "reduction in the quality and supply of water to the State" among many other harmful consequences.[17]

It is well documented that the impacts of climate change and refinery pollution disproportionately impact low-income and fence line communities-of-color. The Air District notes:

> Despite progress in reducing PM levels and related health impacts, exposure to fine PM remains the leading public health risk, and contributor to premature death, from air pollution in the Bay Area.[18]

This stark statement even underestimates personal exposure to refinery combustion related pollutants. A study of indoor air near the Chevron Richmond Refinery determined that Richmond residents are consequently exposed to higher levels of $PM_{2.5}$ in their homes than outdoors.[19] Research concluded that refinery and port emissions of sulfates, nickel, and vanadium, which are among the most harmful components of $PM_{2.5}$, penetrated indoors.[20] The pollution in nearly half of the fence line community homes tested exceeded California's ambient air quality standards for $PM_{2.5}$.[21]

Refineries make up eight of the top ten California facilities that disproportionately pollute in such low-income communities of color.[22] A switch to refining a lower quality feedstock will simply increase that PM and PM precursor pollution. GHG and particulate air pollution co-emit from the same combustion sources and causes in refineries, including intensive energy use that is driven by lower quality oil feedstock.[23] Indeed, the Air District itself has shown that a multi-pollutant approach to such combustion emissions from refineries is effective and necessary.[24] The Air District should adopt a limit on GHGs *as well as* its co-pollutants: PM, SO_2, and NO_X. The proposed Emission Caps do just that.

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[16] *See* Ultramar, Inc. v. South Coast Air Quality Management Dist. (1993) 17 Cal.App.4th 689, 706-08.

[17] Cal. Health and Safety Code § 38501.

[18] BAAQMD Summary of PM Report (2012), available at http://www.baaqmd.gov/~/media/files/planning-and-research/plans/pm-planning/summary-of-pm-reportnov7.pdf.

[19] Julia Brody et. al., Linking Exposure Assessment Science With Policy Objectives for Environmental Justice and Breast Cancer Advocacy: The Northern California Household Exposure Study (2009).

[20] *Id.* at S605.

[21] *Id.* at S604.

[22] Pastor, Morello-Frosch, Sadd, Scoggins, *Minding the Climate Gap*, Executive Summary, p. 7, available at https://dornsife.usc.edu/assets/sites/242/docs/mindingthegap_executive_summary.pdf.

[23] *See* the expert analysis and evidence discussed in and provided as attachments to CBE's Supplemental Comment on Air District Staff Proposal, Rules 12-15 and 12-16; Evidence of Increasing Bay Area Refinery GHG and $PM_{2.5}$ Emissions, October 2015.

[24] May 2016 Draft Staff Report for Rule 12-16, *Options for Reducing Refinery Combustion Emissions,* at 1–6.

Finally, a timely emissions cap is also crucial because of the well-documented problem of "infrastructure inertia."[25] Refining lower quality crudes requires infrastructure modifications and these modifications tend to make future emissions reductions much more difficult as such projects become "locked in." In the Bay Area, these projects so far include the Richmond Chevron Refinery Modernization Project, the Phillips 66 Rodeo Refinery Propane Recovery Project, and the Valero Benicia Refinery Crude by Rail Project. The Air District has acknowledged that "it is reasonable to expect" that the Bay Area refineries will "follow the general industry-wide trend towards increased processing of lower quality crudes," and that processing these crudes will "cause more emissions."[26] In addition, like Assembly Bill ("AB") 32, the Intergovernmental Panel on Climate Change warns against the permanent impacts of new commitments to continue using fossil fuels,[27] and subsequent authoritative analysis[28] indicates that virtually all of the remaining "tar sands" oil resources cannot be produced, refined, or otherwise burned without risking severe and irreversible climate impacts. Put simply, time is of the essence, and it is necessary and reasonable for the Air District to limit emissions now to protect public and worker health and safety.

B. Adoption of Emission Caps Complements and Furthers the Goals of AB 32

Also contrary to industry comments, adoption of a GHG Emission Cap is not duplicative of, but rather, complements California's current regulatory system of addressing GHG emissions. In addition, any suggestions that a GHG Emission Cap will contribute to "leakage" are misplaced and irrelevant.

Emission Caps Are Not Duplicative of AB 32

"Nonduplication" means that a regulation does not impose the same requirements as an existing state or federal regulation, unless a district finds that the requirements are necessary or proper to execute the powers and duties granted to, and imposed upon, a district.[29] The Emission Caps provide an additional regulation, and should not be confused with the "cap" of the State's cap-and-trade program. Alternatively, for the reasons detailed herein, Emission Caps are a necessary and proper exercise of the Air District's authority to protect public and worker health and safety.

In 2006, the Legislature passed The Global Warming Solutions Act (AB 32) declaring that global warming poses a "serious threat to the economic well-being, public health, natural resources, and the environment of California."[30] To counteract this threat, CARB was tasked with designing and implementing measures to lower statewide greenhouse gas emissions to 1990 levels.[31]

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[25] Jim Williams, ARB Chair's Lecture Series, 13 May 2015; www.arb.ca.gov; *See* Davis et al., 2010. *Science.* DOI: 10.1126/science.1188566; Williams et al., 2011 *Science.* DOI: 10.1126/science.1208365; and Williams, 2015 ARB Chair's Lecture Series; 13 May 2015.

[26] *Id.*

[27] IPCC Fifth Assessment Report, available at www.ipcc.ch/report/ar5/index.shtml.

[28] McGlade and Ekins, 2015. The geographical distribution of fossil fuels unused when limiting global warming to 2 ºC. *Nature* 517: 187. DOI: 10.1038/nature14016.

[29] Cal. Health and Safety Code § 40727.

[30] Cal. Health and Safety Code § 38501(a).

[31] Cal. Health and Safety Code §§ 38560-65.

One such distinct measure is the cap-and-trade program, where refiners that lower emissions can sell pollution "Allowances." An Allowance is an integral part of the cap-and-trade program, which sets a "cap" on statewide GHG emissions *economy*-wide. Even the refining industry as a whole has no cap on GHG emissions, and moreover, <u>there is no facility cap</u>. The economy-wide cap decreases over time, thereby achieving GHG emission reductions throughout the cap-and-trade program's duration, currently until 2020. Each participating facility is then required to surrender one permit to emit, the majority of which will be cap-and-trade Allowances, for each ton of GHG emissions that they emit. The refining industry also receives certain "free allowances," and can purchase additional allowances at auction or from third parties. A GHG Emission Cap on refineries—that prevents facility emissions from increasing—is clearly a different type of requirement than the state's economy-wide cap. As detailed below, nothing in AB 32 restricts an air district's inherent authority to also regulate GHG emissions from stationary sources and such efforts are complementary to the State's GHG reduction goals.

AB 32 Does Not Preempt Adoption of Emission Caps

State preemption of local regulation is either express or implied. The legislature can include plain language in a provision stating that it will preempt any local regulation.[32] Alternatively, state laws may contain language clearly indicating that the subject matter is too important to the state to "tolerate . . . [local] action," or the subject matter is otherwise "fully and completely covered" by the state.[33]

Implied preemption cannot occur when "the Legislature has expressed its intent to permit local regulations."[34] AB 32 explicitly allows air districts to pass their own emission reduction requirements: "[n]othing in this division shall limit . . . the existing authority of any [air] district.[35] There is simply no issue of preemption in this case.

Emission Caps Are Complementary GHG Reduction Mechanisms to AB 32

In fact, Emission Caps are complementary to AB 32. As CARB states:

> AB 32 requires California to reduce its GHG emissions to 1990 levels by 2020—a reduction of approximately 15 percent below emissions expected under a "business as usual" scenario.

The timing of this goal is essential. In 1990, the refining industry's "business as usual" did not reflect the industry-wide shift to lower quality oils, such as tar sands. Moreover, the Legislature passed AB 32 in 2006. Only later did communities in Richmond, and California for that matter, first learn about the industry's potential shift to a dirtier crude feedstock in addressing the Chevron Richmond Refinery's Hydrogen Renewal Project—the first of the many

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[32] *See, e.g.,* Cal. Water Code §521(f) ("It is the intent of the Legislature that this chapter supersede and preempt all enactments and other local action of cities and counties, including charter cities and charter counties, and other local public agencies that conflict with this chapter.").

[33] O'Connell v. City of Stockton (2007) 41 Cal.4th 1061, 1068.

[34] Valley Vista Services, Inc. v. City of Monterey Park (2004) 118 Cal.App.4th 881, 887.

[35] Cal. Health and Safety Code § 38594.

refinery infrastructure expansion projects to enable the refining of lower quality oils that we see today.[36] The Air District's cited Congressional Research Service's report on "Changing Markets and Fuel Policies" was not released until 2010.

In 2006, the cap-and-trade program was just not designed to account for a sudden surge in GHG emissions as a result of the relatively more recent refining phenomenon of seeking lower quality crudes. The potentially massive increase in climate-disrupting pollution may well derail the AB 32 program. An Emissions Cap is not only complementary, but also necessary, to ensure attainment of 1990 levels of GHG emissions by 2020. And, as described herein the Air District has the authority to abate the disproportionate quantity of GHG, PM, NO_x, and SO_x pollution emitted by local refineries to ensure GHG emissions trajectories are consistent with state and federal climate change policy goals, and to protect public and worker health and safety.

In addition, an Emissions Cap does not interfere with CARB's administration of the cap-and-trade program. The purpose of the cap-and-trade program in this instance is to ultimately reduce GHG emissions, and a stricter refining facility-specific cap simply furthers that purpose. Although an Emissions Cap may decrease the need for Bay Area refiners to purchase Allowances, it would not create any Allowances to sell elsewhere in the state because it would not force any emission reduction, and all covered sources including refineries would still be subject to the economy-wide cap-and-trade cap. Similarly, this would not incentivize other California refiners to pollute any more than the existing option for those California refiners to purchase additional offsets should they choose to increase facility GHG emissions.[37]

Furthermore, despite recent CARB action, given the uncertainty of the cap-and-trade program after 2020, the Air District has a responsibility to protect its jurisdiction from increased refinery emissions now. Two cases are making their way through the courts challenging the legality of cap-and-trade.[38] In addition, the purchase of Allowances has recently significantly declined, raising subsequent questions regarding the success, or failure, of the cap-and-trade program.[39] Reliance on cap-and-trade as the sole long-term solution to address GHGs is speculative.

AB 32 acknowledges that global warming cannot be remedied without national and international actions, but it also acknowledges that California's efforts "will have far-reaching effects by encouraging other states, the federal government, and other countries to act."[40] Likewise, an Emissions Cap will encourage other local, state, and federal bodies to take action,

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[36] Communities for a Better Environment v. City of Richmond (2010) 184 Cal.App.4th 70.

[37] An allowance is a tradable permit to emit CO_2. It is *not* an offset. By contrast, refiners can avoid regional pollution reduction requirements by purchasing a number of "offsets" from carbon-saving projects, such as reforestation or forest management projects, elsewhere in the United States or Quebec.

[38] *See* Court of Appeal Turns a Careful Eye Toward Challenges to California's Cap-and-Trade Auction System, April 26, 2016, available at http://www.lexology.com/library/detail.aspx?g=5116b146-bcff-41e3-829b-c54eeb58b597.

[39] *See, e.g.*, California Comes up $600M Short From Cap-And-Trade Auction, May 2016, available at http://www.law360.com/articles/801003/calif-comes-up-600m-short-from-cap-and-trade-auction; California's cap-and-trade carbon emission system may be failing, May 2016, available at http://www.sacbee.com/news/politics-government/politics-columns-blogs/dan-walters/article80107032.html; California Cap-and-Trade Program and Québec Cap-and-Trade System May 2016 Joint Auction #7 Summary Results Report, available at http://www.arb.ca.gov/cc/capandtrade/auction/may-2016/summary_results_report.pdf.

[40] Cal. Health and Safety Code §38501(d).

and, importantly, would inform the state about the refinery sector's capacity for GHG reductions in its development of a post 2020 economy-wide cap.

This is consistent with the most recent United Nations Framework Convention on Climate Change, convened in Paris, France. Several representatives of "sub-national" organizations, including the State of California, were present. California was one of the leaders of the sub-national grouping, and Governor Brown signed the Subnational Global Climate Leadership Memorandum of Understanding,[41] clarifying the role, responsibility and authority of any local or regional agency in California to take official action within the areas under its authority to fight climate change. Setting an Emission Cap on GHGs here will lay the path for more effective future statewide policy, and at a minimum, the development of successful and robust post-2020 GHG emission reduction strategies.

"Leakage" Is Irrelevant to Adoption of Emission Caps

Health & Safety Code §38505(j) defines leakage: "a *reduction* in emissions of greenhouse gases within the state that is offset by an increase in emissions of greenhouse gases outside the *state* (emphases added.)" To reiterate, the proposed Emission Caps will not require any change to current refinery operations—they are intended to act as a backstop and to stop refinery emissions from increasing. They propose no mandate to decrease or reduce emissions. Also, the proposed Emission Caps would not increase production by refineries in other states to supply the fuels that we need in California. This is because the proposed Emission Caps do not require any change in refinery petroleum or other fuel production, which currently far exceeds California demand.[42] As there is neither a reduction in emissions, nor any perceived out-of-state shift in GHG pollution to meet California petroleum product demand, the issue of leakage is wholly irrelevant to the consideration of the proposed Emission Caps.

C. Adoption of Emission Caps Would Not Constitute "Takings"

Several industry commenters have stated that the imposition of Emission Caps would constitute an unconstitutional "taking." This assertion is unsupported. Adoption of the proposed Emission Caps would not constitute a "taking," and, for the sake of argument, even if it did, it would still be within the police power of the Air District, constituting a valid, constitutional use of its broad authority.

First, there is no takings issue as there is no "property" at issue. The concept of takings comes from the California Constitution: "[p]rivate property may not be taken for public use without just compensation being made to the owner."[43] In this instance, the "property" that could be subject to takings are arguably the refiners' current permits: that there is some right of ownership in a permit to pollute or emit up to a certain amount of GHGs, PM, NO_X or SO_2 beyond those required by the Emission Caps. Such a position overlooks the essence of the proposal: the Emission Caps do not mandate any reduction in emissions, but simply seek to stop

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[41] *See* Under 2 Subnational Global Climate Leadership Memorandum of Understanding, available at http://under2mou.org/.

[42] *See* CBE Comment on Factual Information Regarding Global Climate Impacts of Bay Area Oil Refining to be Included in the EIR for Proposed Rule 12-16, June 29, 2016.

[43] Cal. Const., art. I, § 14.

emissions of these four pollutants from increasing beyond current levels. The only way some "property" could be involved is if there is some "vested right" to pollute above current levels, and up to maximum permitted levels of pollution. It is well settled, however, that refinery permits give [the refiner] <u>no vested right to pollute</u> the air at any particular level.[44]

Second, for the sake of argument, even if such vested rights did exist, "the constitutional guaranty [against takings] . . . does not extend to the state's exercise of its police power."[45] This established precedent dates back to 1965, in *Lees v. Bay Area Air Pollution Control District*. In *Lees*, a property owner held a long-standing practice of using an incinerator for the disposal of rubbish and garbage at the property. The Air District enacted a regulation imposing emission limits on such incinerators. Application of that regulation in effect also practically prohibited the use of those incinerators. The property owner sued the Air District, arguing an unconstitutional taking of his private property. The court disagreed. The court reasoned that an "[Air Pollution Control] District's regulation . . . [to] protect the purity of the air" is within the State's police power. "The District exists for that very purpose. Its regulation is not only reasonable, but indeed essential, and represents a lawful and proper exercise of the police power."[46] In *Lees*, the court upheld an Air District regulation that both limited emissions, and practically made it impossible to use certain polluting equipment that had traditionally been used as general practice. Emission Caps prove far less stringent—they would not preclude the use of any refinery equipment and as currently proposed do not even require emissions to decrease. In comparison, Emission Caps are a narrower, more specific use of an Air District's police power.

To clarify and emphasize this point with a more recent case, this police power applies to adoption of a rule that would affect a validly held permit for the use of a certain pollutant. In the *Ultramar* case, it did not matter that Ultramar had a permit for the use of hydrogen fluoride ("HF"); irrespective of that claim of vested right, the court determined that Rule 1410 was an authorized use of an air district's police power. The same decision also acknowledged an air district's authority to prevent foreseeable releases of a pollutant even before an actual release of the pollutant. The courts determined that Rule 1410 was a valid exercise of an air district's authority based on the "possibility of an accidental release" of HF.

In fact, courts employ a highly deferential standard of review to air district regulations.[47] An unlawful regulation must prove "so palpably unreasonable and arbitrary as to show an abuse of discretion as a matter of law."[48] They must reach the level of "arbitrary, capricious, or without reasonable or rational basis" and be "*entirely* lacking in evidentiary support."[49] In adjudicating the legality of an agency regulation, a court will only inquire as to whether the

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[44] *See* Sherwin–Williams Co. v. South Coast Air Quality Management Dist. (2001) 86 Cal.App.4th 1258, 1273; Mobil Oil Corp. v. Superior Court (1976) 59 Cal.App.3d 293, 305; Ultramar, Inc. v. South Coast Air Quality Management Dist. (1993) 17 Cal.App.4th 689.

[45] Milton H. Lees v. Bay Area Air Pollution Control Dist. (1965) 238 Cal.App.2d 850, 857.

[46] *Id.*

[47] *See, e.g.*, Sonoma County Water Coalition v. Sonoma County Water Agency (2010) 189 Cal.App.4th 33 (holding that even though the Coalition may have had a "fair argument," the agency was afforded deference regarding its projections of the county's water supply); California Bldg. Industry Ass'n v. San Joaquin Valley Air Pollution Control Dist. (2009) 178 Cal.App.4th 120, 133-34 (finding the district's use of an air quality model valid despite expert disagreement because "it was up to the District to decide which expert opinion to accept").

[48] Ass'n of Irritated Residents v. San Joaquin Valley Unified Air Pollution Control Dist. (2008) 168 Cal.App.4th 535, 552.

[49] American Coatings Ass'n v. South Coast Air Quality Dist. (2012) 54 Cal.4th 446 (emphasis added).

agency has demonstrated a *rational* connection between the relevant factors and the adopted rule.[50] As detailed herein, adoption of Emission Caps are necessary to protect public and worker health and safety and maintain California's climate goals, and far exceeds such a standard of review.

II. Development of an Environmental Impact Report Is the Proper Procedural Avenue to Develop or Clarify Necessary Findings

The Air District "agrees that its legislative authority is broad enough to establish [E]mission [C]aps."[51] The Air District's reluctance to proceed with adequate administrative procedures regarding the Emission Caps proposal rests with the assertion of the need to still establish a record.[52] For the reasons detailed herein, the commenters believe that such a record has already been established. Nevertheless, the time to determine whether that record is adequately supported is during the CEQA review process:

> A fundamental purpose of CEQA review is to provide decision makers with information they can use in deciding whether to approve a proposed project [or rulemaking], not to inform them of the environmental effects of projects [or rulemaking] that they have already" decided to adopt.[53]

The California Supreme Court has made this point clear: if decisions as to which project to adopt were made prior to CEQA review, it would turn those environmental review mandates on their head, and "EIR's would likely become nothing more than *post hoc* rationalizations to support action already taken."[54] In other words, should the Air District still believe that a record supporting adoption of Emission Caps is lacking, it should for that very reason immediately commence CEQA review of the much-needed proposal to demonstrate its unequivocal benefits to climate, and public and worker health and safety.

The commenters support the Air District Board of Directors' recent direction to Air District staff to immediately commence this CEQA review. In addition, we clarify that such adequate review must consider the proposed Emission Caps as a proposed project, versus under an insufficient and less robust alternatives analysis.

III. Emission Caps Are Necessary to Prevent Increased Pollution from Refining Lower Quality Crude Oil Feedstock in the Bay Area

Lower Quality Oils Are Replacing Traditional California Sourced Oils

It is well documented that Bay Area refineries are shifting to lower quality oil feedstock. The continuing substantial decline in their current and traditional major oil feedstock sources

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[50] *Id.*

[51] Attachment 10G to Stationary Source Committee Meeting Agenda, September 21, 2015 "Concerns about Setting Numeric Caps at Current Levels," available at http://www.baaqmd.gov/~/media/files/board-of-directors/2015/bod_agenda_100715.pdf?la=en.

[52] *Id.*

[53] Laurel Heights Improvement Ass'n. v. Regents of University of California (1988) 47 Cal.3d 376, 394.

[54] *Id.*

requires the refiners to switch oil sources in order to maintain production.[55] The industry and the refiners themselves have asserted repeatedly and unequivocally that they seek a switch to new oil feedstock including tar sands bitumen-derived oils, an extremely low-quality refinery feedstock.[56] Multiple independent expert analyses of specific projects proposed and planned in virtually all major parts of the Bay Area refining industry confirm that refiners are committing long-lasting capital infrastructure for this purpose.[57] In fact, the potential for an imminent shift to lower quality oil feedstock in the Bay Area refining industry is beyond reasonable dispute.

Refining Lower Quality Oils Increases Air Pollution

The Air District 2012 Concept Paper asserted that "the use of lower quality crude at refineries could . . . increase emissions of air contaminants . . . . Emissions could also increase as a result of accidents related to the increased corrosiveness of lower quality crudes."[58] Recently, the Air District has repeated the essence of this finding in different words, stating that changes in crude "can result in significant changes in combustion needs" at refineries.[59]

Multiple expert analyses and peer-reviewed reports document this relationship. This evidence has found a direct causal relationship between lower quality oil feedstock, increased refinery energy intensity, and increased refinery emissions of CO_2 and other combustion products, including PM, NOx, and SOx. In addition, this causal relationship between lower quality oil feedstock and increased refinery emissions is quantitatively predictable across the refining sector for a given product slate.[60] Further, the US Chemical Safety Board found a direct causal relationship between lower quality oil feedstock and the mechanical causes of catastrophic fire and air pollution episodes at Bay Area refineries. Two examples of these catastrophic episodes are the corrosion caused by a denser crude feed in the fatal Tosco Martinez refinery fire of 1999,[61] and the pipe corrosion failure accelerated by higher sulfur oil in the Chevron Richmond refinery fire that sent some 15,000 residents to seek medical attention in 2012.[62]

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[55] *See* California Energy Commission data (*Oil Supply Sources to California Refineries: Crude Oil Supply Sources to California Refineries*, http://www.energy.ca.gov/almanac/petroleum_data/statistics/crude_oil_receipts.html) and forecasts (*Transportation Energy Forecasts and Analyses for the 2009 Integrated Energy Policy Report;* 2010; CEC-600-2010-002-SF; pages 134–143; and *Transportation Energy Forecasts and Analysis for the 2011 Integrated Energy Policy Report;* 2011; CEC-600-2011-007-SD; pages 195–207), California Energy Commission, Sacramento, CA.

[56] See the expert analysis and evidence discussed in and provided as attachments to Communities for a Better Environment's *Supplemental Comment on Air District Staff Proposal, Rules 12-15 and 12-16; Evidence of Increasing Bay Area Refinery GHG and $PM_{2.5}$ Emissions;* provided for the record in this matter on 21 October 2015.

[57] See for example the discussion of expert opinions on Chevron's originally proposed Richmond Refinery "Renewal Project" in Communities for a Better Environment v. City of Richmond (2010) 184 Cal.App.4th 70; Expert Report of P Fox and P Pless dated 5 December 2014 regarding EIR SCH# 2012072046; Expert Report of G. Karras dated 5 December 2014 regarding EIR SCH# 2012072046; Expert report of P Fox dated 27 January 2014 regarding EIR SCH# 2013071028; Expert Report of G Karras dated 23 February 2016 regarding EIR SCH# 2013071028; Expert Report of P Fox dated 8 February 2016 regarding EIR SCH# 2013052074; and Expert Report of G Karras dated 30 March 2016 regarding EIR SCH# 2013052074.

[58] *Id.*

[59] May 2016 Draft Staff Report for Rule 12-16, *Options for Reducing Refinery Combustion Emissions,* at 6.

[60] See the expert analysis and evidence discussed in and provided as attachments to Communities for a Better Environment's *Supplemental Comment on Air District Staff Proposal, Rules 12-15 and 12-16; Evidence of Increasing Bay Area Refinery GHG and $PM_{2.5}$ Emissions;* provided for the record in this matter on 21 October 2015.

[61] *Investigation Report: Refinery Fire Incident;* Report No. 99-014-I-CA; March 2001, *available at* www.csb.gov.

[62] *Interim Investigation Report: Chevron Richmond Refinery Fire;* final report adopted 19 April 2013, *available at* www.csb.gov.

Importantly, some of these impacts are documented industry-wide by publicly available data. As one peer reviewed study[63] reports, "[s]trongly coupled increases in energy and crude stream processing intensities with worsening oil quality [were shown based on] observations from operating plants across the four largest U.S. refining districts over 10 years." And as another study[64] reports, refinery "energy use has a positive linear relationship with GHG emissions."

The Air District has resolved to reduce Bay Area climate disrupting emissions to 80% below 1990 levels by 2050,[65] and plans to reaffirm this goal in its upcoming 2016 Clean Air Plan.[66] These GHG reduction goals are in jeopardy if refineries begin processing lower quality oils without an adequate backstop to prevent the consequent massive increase in GHG emissions. In addition, the Air District recently issued its "Five Point Action Plan to Address Refinery Emissions," which specifically stated a goal to "cap" criteria pollutants and otherwise ensure that refinery feedstock changes do not "increase health burden[s]."[67]

Emission Caps Prevents Those Increases in Air Pollution

In September 2015, in order to directly address this potentially drastic increase in GHGs, PM and PM precursor emissions, CBE provided the Air District with its formal proposal for Emission Caps. The Emission Caps target four pollutants: GHGs, PM, and NO_X and SO_2 (both PM precursors). Publicly available data[68] forms the basis of these proposed limits. These limits consist of the maximum-year actual emissions of the refineries over the last few years, plus a "buffer" factor to account for random fluctuations in emissions.[69] As currently proposed, Emission Caps essentially keep refinery emissions of these four pollutants at current levels.

The Emission Caps proposal focuses on these four pollutants for a specific reason. Refining a lower quality oil feedstock requires increased refinery cracking processes, fuel combustion and hydrogen production.[70] These same refinery processes are the largest sources of GHG and PM emissions.[71] As these processes work harder, emissions of those pollutants increase. As stated, there is a clear and quantifiably predictable causal relationship between lower quality oil feedstock, increased refinery energy intensity, and increased refinery emissions

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[63] Karras, 2010. Combustion Emissions from Refining Lower Quality Oil: What is the Global Warming Potential? *Environmental Science & Technology* **44**(24): 9584–9589. DOI: 10.1021/es1019965.

[64] Abella and Bergerson, 2012. Model to Investigate Energy and Greenhouse Gas Emissions Implications of Refining Petroleum: Impacts of Crude Quality and Refinery Configuration. *Environmental Science & Technology* 46: 13037–13047. DOI: 10.1021/es/3018682.

[65] Bay Area Quality Management District Resolution 2013-11, Adopting a Greenhouse Gas Reduction Goal and Commitment to Develop a Regional Climate Protection Strategy, available at http://www.baaqmd.gov/~/media/files/board-of-directors/adopted-resolutions/2013/2013-11.pdf.

[66] Bay Area Air Quality Management District Draft Staff Evaluation Report, Options for Reducing Refinery Combustion Emissions (June 15, 2016), available at http://www.baaqmd.gov/~/media/files/board-of-directors/2016/bod_agenda_061516-pdf.

[67] Five Point Action Plan for Reducing Refinery Emissions, available at http://www.baaqmd.gov/~/media/files/board-of-directors/2015/z-presentations/052715-ssc-presentations.pdf?la=en.

[68] *See* CBE Comment, Proposal for Enforceable Numeric Limits on Refinery-wide Emissions to Stop Increasing Greenhouse Gas and Particulate Matter Air Pollution [Rule 12-16], September 18, 2015, pp.5-6, detailing selection of 2011-2013 data as representative of current refinery-wide emissions.

[69] *Id.*

[70] See Attachment A at 3-4.

[71] *Id.*

of CO_2 and other combustion product pollutants. Moreover, these refinery combustion emissions include PM and the PM precursors NO_X and SO_2. Evidence developed during this rulemaking shows that PM, NO_X, SO_2, or more than one of these pollutants that cause $PM_{2.5}$ air pollution, co-emit with GHGs from at least 379 sources in the Bay Area refining industry.[72] The direct relationship between the increases in these pollutants and increased refining of lower quality oils, calls for more stringent preventative regulations to stop emissions of those local and climate damaging pollutants from increasing.

Because of the relationship between emissions of targeted pollutants and the quality of oil refined, adoption of Emission Caps would also help to limit the use of more corrosive, inherently hazardous refinery oil feedstocks, thereby reducing the likelihood of episodic emissions from flaring and catastrophic incidents.

Emission Caps prevent an increase in emissions from refining lower quality oil in order to protect public and worker health and safety, and in order for the Air District to meet its broader GHG emission reduction goals. Air District reports have stated the same. The Air District's 2012 Concept Paper called for a "backstop" to increasing refinery emissions. Similarly, the Air District's recent staff report concluded that "refineries are a top priority" on account of impending changes in crude quality.[73] This is further clarified in the Air District Resolution 2014-7, directing the proposal of a backstop that will "set emissions thresholds and mitigate potential emissions increases" because Bay Area refineries are undergoing infrastructure and crude slate changes that can "result in significant worsening of air quality."[74] The record clearly establishes the need for Emission Caps as a backstop to increasing pollution from refining lower quality oil feedstock.

Facility-wide limits on air pollution are also far from a novel concept. To the contrary, air districts have a history of facility-wide emissions regulations. For instance, SCAQMD's Rule 1420 does not allow a lead-processing facility to discharge emissions above a certain ambient concentration.[75] Federal and state regulations have also targeted facility-wide emissions. The US EPA recently adopted facility-wide benzene sampling limits as part of its fence line monitoring rule.[76] In 2006, California enacted Senate Bill 1368 (Perata), providing facility-wide limits on GHG emissions from power plants.[77]

Finally, the Air District's current regulatory framework is simply not capable of addressing the increasing pollution from refineries on account of the quality of oil refined. PM emissions from refineries include environmentally significant amounts of ultra-fine PM ("UFPM"). The Air District does not currently measure or otherwise effectively control UFPM.

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[72] CBE Supplemental Comment on Air District Staff Proposal, Rules 12-15 and 12-16; Evidence of Increasing Bay Area Refinery GHG and PM2.5 Emissions, October 21, 2015.

[73] Bay Area Air Quality Management District Draft Staff Evaluation Report, Options for Reducing Refinery Combustion Emissions (June 15, 2016), at 1-7, available at http://www.baaqmd.gov/~/media/files/board-of-directors/2016/bod_agenda_061516-pdf.

[74] Bay Area Quality Management District Resolution 2014-7, Addressing Emissions from Bay Area Petroleum Refineries, available at http://www.baaqmd.gov/~/media/files/board-of-directors/adopted-resolutions/2014/2014-07.pdf.

[75] SCAQMD Rule 1420 Emissions Standard for Lead, available at http://www.arb.ca.gov/DRDB/SC/CURHTML/R1420.HTM.

[76] *See* Federal Register, Vol. 80, No. 230, December 1, 2015 at 75192, available at https://www.gpo.gov/fdsys/pkg/FR-2015-12-01/pdf/2015-26486.pdf.

[77] *See* SB 1368 Emission Performance Standards, *available at* http://www.energy.ca.gov/emission_standards/.

Other pollutant specific air quality rules regulate certain pollutants from certain sources at refineries, but not comprehensively. For instance, SO_2 has certain concentration limits at certain refinery process units, such as sulfur recovery units or catalytic cracking units; NO_x is also regulated, but only for boilers, process heaters and steam generators.[78] Remarkably, however, none of the Bay Area refineries have "overall mass emission limits that apply to the entire refinery."[79]

The Air District's current discretionary policies for implementing Regulation 2, Rule 2 (New Source Review [NSR]) as it applies to refinery operations, and its lack of adequate emission and monitoring standards in pollutant specific rules, such as Regulation 6 (Particulate Matter), have also proven insufficient to deal with this problem of increasing pollution. Much of this is attributable to years of permitting decisions that ignored changes in upstream raw materials (i.e. the quality of crude slates) and existing upstream physical limitations on production increases. At the same time, permitting decisions classified changes to downstream infrastructure as "alterations" rather than "modifications." An accurate classification as a modification would have triggered Best Available Control Technology requirements, as well as throughput and emission limits. Instead, by classifying such changes as merely alterations, refineries "de-bottlenecked" operations over time, and grew their capacity without triggering a full and adequate NSR.

Permits for new and modified sources from virtually all industries in the Bay Area, other than refineries, include permit conditions that specify the composition and quantity of raw materials used for their processes. Those industries therefore have facility-wide emission caps. If Air District refinery permit decisions had considered upstream material feed and existing upstream physical process limitations, far more refinery project applications would have received adequate review as modifications, instead of alterations. These projects thus would have been permitted with more environmentally protective emission limits. Throughput and emission limits on virtually all refinery-processing equipment would have been imposed long ago. Today, it is long past the time for the Air District to establish an effective regulatory structure to address known increasing emissions from refining a lower quality oil feedstock, and also, the significant increase in episodic emissions, should they consequently occur.

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[78] BAAQMD Regulatory Concept Paper, Petroleum Refining Emissions Tracking Rule, Draft, October 15, 2012, citing The U.S. Oil Refining Industry: Background in Changing Markets and Fuel Policies" (Nov. 22, 2010), available at http://www.baaqmd.gov/~/media/files/planning-and-research/rules-and-regs/workshops/2013/1215_dr_rpt032113.pdf?la=en.

[79] *Id.*

IV. Conclusion

For the reasons stated above, adoption of the Emission Caps is consistent with the requirements of the Health and Safety Code, would complement and further the goals of AB 32, and would not constitute a "takings." CEQA is the proper procedural avenue to develop or clarify necessary findings supporting adoption of Emission Caps. Finally, in light of the time-sensitive and important need for this protective measure, we also agree with the Air District Board of Directors' direction to prepare this measure for an adoption hearing "as expeditiously as possible."

Respectfully Submitted,

Roger Lin, Staff Attorney
Richard Treadwell
Dana Bass
Daniel Lopez
on behalf of Communities for a Better Environment

Laurence G. Chaset, Attorney at Law
Sustainable Energy Futures
on behalf of 350 Bay Area

Devorah Ancel, Staff Attorney
on behalf of Sierra Club

From: rollnglu@gmail.com
Sent: Sunday, May 7, 2017 8:01 PM
To: Victor Douglas
Subject: Comments for Draft EIR for Reg 11 Rule 18 and Reg 12 Rule 16

Dear Mr. Douglas,

My name is Shawn Lee. I am a resident of Hercules, California.

I have a few comments on the Draft EIR for Reg 11-18 and Reg 12-16.

Chapter 3 Environmental Setting
On your table 3.2-2 (Bay Area Air Pollution Summary – 2015), Why is the cities that are near refineries have data missing? I would have expected the Air District would have a complete set of data for areas near Refineries. I am concerned that the refineries are misrepresented in their area.

Table 3.2-4 shows that Refineries are the lowest in PM 10, PM 2.5, SO2, and NOX. I question the need for rules on the refineries as they are not the significant cause of emissions per your table.

Green House Emissions Impacts - Page 1-10
Your EIR *States "Presuming continuing increases in gasoline consumption results in unreasonable levels of speculation. For example, it is impossible for the Air District to predict the exact level of gasoline consumption in 2018 and how that would relate to Bay Area refinery capacity and how the market might react if production at Bay Area refineries were constrained by Rule 12-16. Therefore, the Air District is assuming, based on historical data that potential GHG emission impacts from the proposed project are concluded to be less than significant."*

I do not think that the fact that the inability to predict the impact of gasoline consumption, means that you can use historical data and deem the impacts are less than significant. The project is going to impact prices and consumption. Even though the Air District does not have the exact level of gasoline consumption, the project should use resources from the California Energy Commission to determine impacts.

I appreciate that you will consider my comments in this EIR.

Regards,

Shawn Lee (via email)

COOPER
WHITE &
COOPER

Direct Line: (415) 765-6272
E-Mail: kcasto@cwclaw.com

May 5, 2017

Mr. Victor Douglas
Principal Air Quality Specialist
Bay Area Air Quality Management District
375 Beale Street
San Francisco, California 94105

Re: Draft Environmental Impact Report ("DEIR")
for Proposed BAAQMD Rules 11-18 and 12-16

Dear Mr. Douglas:

As outside counsel for the Shell Martinez Refinery (Shell), we have been asked to submit the attached comments related to above-referenced DEIR. Please note that where a comment references a title or a chapter of the DEIR, the comment applies to any similar discussion in the Executive Summary of the DEIR and/or Staff Report.

As a general matter and apart from any other specific comments, we believe the DEIR is fatally flawed under the California Environmental Quality Act ("CEQA") because of its limited scope; that is, its failure to comprehensively address the cumulative effects of these proposed rules in conjunction with the battery of rules which have already been directed by the District in recent years towards oil refineries as part the District's Refinery Strategy. Moreover, the DEIR conspicuously omits any analysis of the companion proposed District Rule 13-1 which is also directed at refineries, which was proposed at the same time this DEIR was issued and which is currently scheduled for promulgation at approximately the same time as these rules. This glaring omission renders much of the DEIR's analysis limited, superficial, speculative and incoherent as it applies to complex facilities such as refineries. Therefore, we believe that CEQA demands that this DEIR be withdrawn, expanded, rewritten and recirculated in a more comprehensive and coherent format.

We appreciate this opportunity to submit these comments and look forward to our continuing involvement in the public participation process for these rules.

Very truly yours,

Keith M. Casto

Keith M. Casto

KMC:mcb
Enclosure
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The Draft Environmental Impact Report (DEIR) has several substantial flaws that need to be addressed in order to meet the requirements under the California Environmental Quality Act (CEQA). The document had several omissions of statutory requirements under CEQA that were not adequately addressed in the DEIR. The document has numerous technical concerns that need to be addressed to adequately describe the potential environmental impacts. In addition, there are numerous instances of editorial mistakes in the DEIR which makes it confusing and difficult to follow the document and its conclusions.

1 DEFICIENCIES WITH REQUIREMENTS UNDER CEQA

The DEIR is inadequate as it fails to meet several statutory requirements under CEQA. The following sections describe these deficiencies.

1.1 The DEIR Violates CEQA Because it Fails to Address All of the District's Refinery Strategy Rules Comprehensively, Including Proposed Rule 13-1

The District adopted a multi-pronged strategy stemming from District Board of Directors Resolution No. 2014-17. This strategy is described in detail in the Strategy Staff Report as including Rule 12-15, Rule 12-16, the Additional Refinery Rules and the 2016 Refinery Rules., all of which are collectively referred to by the District as comprising its Petroleum Refinery Emissions Reduction Strategy ("Refinery Strategy"). To that end, the District has rolled out a series of interlinked regulations directed at refineries through this Refinery Strategy. This most recent incarnation of refinery regulation takes its form in proposed Rules 12-16 and 11-18, which are scheduled for adoption in May and July. At the same time, the District issued this DEIR, the District also proposed a new Rule 13-1 (which is scheduled for adoption in September) to address GHG emissions at refineries, but failed to include any analysis in this DEIR for this new proposed rule.

All three proposed rules, Rules 11-18, 12-16 and 13-1, are based in one way or another on the information to be gathered under the authority of Rule 12-15, which was promulgated a year ago. As indicated, Rule 12-16 is scheduled for promulgation this month; Rule 11-18 is scheduled for promulgation in July; and Rule 13-1 is scheduled for adoption in September of this year. This unnecessarily accelerated schedule at the tail end of implementation of the Refinery Strategy in conjunction with the discontinuous and piecemeal environmental assessment of the individual component regulations appears to be part of a deliberate and systematic policy by the District to circumvent its CEQA obligations; that is the comprehensive programmatic analysis required by CEQA.

All of these rules are part of and connected through the District's continuing "Refinery Strategy." Proposed Rule 12-16 was at one point directly connected with the information-gathering orientation of Rule 12-15 which was adopted in 2015. In fact, a prior version of Rule 12-15 was packaged together with proposed Rule 12-16 in a previous Draft Environmental Impact Report

("DEIR") which was issued by the District in the fall of 2015 and later withdrawn when Rule 12-15 was adopted and consideration of proposed Rule 12-16 was deferred and revised because of its serious legal inconsistencies with both the federal Clean Air Act and the California Global Warming Solutions Act of 2006 ("AB 32"). Proposed Rule 11-18 is a deliberate spinoff of an early draft version of 12-15. The refinery energy efficiency provisions of proposed Rule 13-1 are a direct outgrowth of a prior version of proposed rule 12-16 and proposed Rule 13-1 is thus intended by the District to be either a substitution for or an extension of proposed Rule 12-16 because of the continuing legal flaws in proposed Rule 12-16.

These rules are also directly linked through the Refinery Strategy with Rules 9-14, 6-5, 8-18 and 11-10. With respect to each of these rules, the District has engaged in a fragmented, piecemeal administrative process to avoid a meaningful, comprehensive programmatic analysis under the California Environmental Quality Act ("CEQA"). That has already resulted in two separate lawsuits based in part on challenges to this fatally flawed CEQA process. (We have attached and incorporate herein copies of the petitioners' briefs in these two cases which fully explicates our CEQA arguments.)

With respect to proposed Rules 12-16 and 11-18, the District once again violated CEQA by segmenting its analysis of multiple rulemaking actions that collectively comprise the District's "Refinery Project." As raised in these prior lawsuits, CEQA demands unified review of "the whole of the action," and a series of actions undertaken to attain the same objective constitutes a single CEQA project. (Tuolumne County Citizens for Responsible Growth, Inc. v. City of Sonora (2007) 155 Cal.App.4th 1214, 1226-27). Under the dictates of Tuolumne County and longstanding core CEQA precepts, the District violated CEQA when it segmented its prior analysis of Rules 12-15 and 9-14 and adopted them in isolation, without any consideration or analysis of the cumulative impacts of the remaining actions taken by the District to achieve its unified objective to more intensively regulate oil refinery emissions. (Tuolumne County, 155 Cal.App.4th at 1226-27). The District has already admitted in court documents that it conceived, developed, and adopted Rules 12-15 and Rule 9-14 as part of a broader, unified effort that encompassed at least seven separate rules that were designed to achieve a single, common objective: tracking and reducing refinery emissions by 20%. As indicated, these particular rules were challenged on the same CEQA ground by certain petitioners (including the Western States Petroleum Association which in turn represents Shell Oil Products U.S.) in the case of Western States Petroleum Association, et al. v. BAAQMD, Case No. N16-0963. This suite of seven rules also include Rules 6-5, 8-18 and 11-10. These latter rules were challenged yet again on the same ground in the case of Valero et al. v. BAAQMD, Case No. N16-0095.

The District's Refinery Project was not developed merely to implement a general, indefinite policy objective, such as "protecting public health" or "ensuring environmental protection." To the contrary, it was developed to implement and achieve a specific and targeted objective to limit refinery emissions by 20%. Proposed Rules 12-16 and 11-18 are simply further steps needed to implement and achieve that specific and targeted objective. Under Tuolumne County and core CEQA precepts, the District violated CEQA yet again when it improperly segmented its analysis of proposed Rules 12-16 and 11-18 and analyzed them in isolation, without any consideration or analysis of the cumulative impacts of its prior regulatory actions in adopting Rules 12-15, 9-14, 8-18, 6-5, 11-10 to achieve its unified programmatic objective.

The obvious connectivity of these rules is further reinforced by the District's follow-on proposal to adopt in September of this year proposed Rule 13-1 with respect to greenhouse gas ("GHG") emissions from oil refineries with the intention to use the crude slate data which it has been seeking to acquire under Rule 12-15 in implementing proposed Rule 13-1. As indicated, the District has acknowledged the proposed Rule 13-1 is more or less either a substitution for or an extension of proposed Rule 12-16 which is scheduled for hearing on May 17, 2017. This is further reinforced by the District's intention to use the cargo vessel emissions data which it has been seeking to collect under Rule 12-15 in the implementation of proposed Rule 11-18, which is also scheduled for public hearing on May 17, 2017.

Proposed Rule 11-18 is no less a part of the District's overall "Refinery Strategy" merely because it was belatedly and disingenuously expanded to encompass facilities besides oil refineries. At one time, it was part of proposed Rule 12-15 and was specifically targeted at refineries. Because of the CEQA challenges already brought for Rule 12-15 and other regulations, it appears that the scope of the new derived proposed Rule 11-18 was deliberately broadened to avoid characterization as a "refinery-only" regulation. As a result, the District does not have the staff to develop health risk assessments for the 1100 facilities now technically covered under the much broader scope of the proposed regulation. As a result, it appears that it will be necessary to reconfigure this regulation to tier the categories of sources affected and prioritize implementation over an extraordinarily long rollout with refineries unsurprisingly anticipated to be the very first facilities addressed.

The DEIR is inadequate because of its omission of any analysis of the impacts of Rule 13-1. On their face, proposed Rules 11-18, 12-16 and 13-1 form a veritable wall of complementary regulation for refineries with each playing a significant part of the District's overall Refinery Strategy. The accelerated and coordinated rollout of these regulations and their intended cumulative impact on the refineries in the Bay Area dictate that this is one integrated and coordinated project. (As evidence of this intent, we attach a PowerPoint Presentation of the District's Eric Stevenson on February 6, 2017 at the Advisory Council Meeting.) This body of targeted regulations has the potential for putting one or more of these Bay Area refineries out of business by depriving them of the operational flexibility to balance load, safety, capacity, product and regulatory compliance. For that reason, these closely coordinated three rules (and actually all of the recent rules targeting refineries under the District's "Refinery Project") should be (and should have been) analyzed comprehensively and programmatically before promulgation. These three rules are deliberately structured so that proposed Rule 13-1 addresses GHG emissions at refineries from a global perspective through a carbon intensity approach; proposed Rule 12-16 targets criteria pollutants at refineries with a facility cap from a regional air quality approach; and proposed Rule 11-18 targets toxic pollutants at refineries from a local impact perspective. Yet proposed Rule 13-1 is conspicuously left out of this analysis even though it is clearly a parallel and interlinked outgrowth of the overall refinery strategy being advanced by the District. For example, the DEIR fails to address how add-on control equipment to meet proposed Rules 12-16 and 11-18 may prevent the effectiveness of proposed Rule 13-1 and vice versa.

In fact, this DEIR affirmatively concludes that proposed Rules 11-18 and 12-16 together have a significant negative co-pollutant impact on GHG emissions. Yet, this DEIR glaringly omits any analysis of the impacts of proposed Rule 13-1 whose efficacy is directly hampered by implementation of proposed Rules 12-16 and 11-18.

Thus, the District repeats the same fatal CEQA segmentation flaw by treating these proposed rules in isolation from proposed Rule 13-1 and the other rules already targeting refineries. This obvious technical and regulatory interconnection cries for programmatic analysis rather than the slipshod, fragmented, haphazard, piecemeal discussion which this DEIR represents. The prior bundling proposed Rule 12-16 with Rule 12-15 in a DEIR in 2015 and later detachment from Rule 12-15 and rebundling with proposed Rule 11-18 in this DEIR is a stark pronouncement of its procedural inadequacy. In fact, if anything, proposed Rule 13-1 may have an even more direct relationship with proposed Rule 12-16 than it does with proposed Rule 11-18. Operationally, Rules 13-1 and 12-16 have reciprocally competing co-pollutant impacts in that compliance with one will negatively impact the other. Ratcheting down on criteria pollutants under Rule 12-16 will directly contribute to higher GHG emissions. Conversely, reduction in GHG emissions by way of carbon intensity regulation and concurrent reduction in throughput under Proposed Rule 13-1 will directly impact increasingly more stringent control strategies for criteria pollutants under proposed Rule 12-16 and control of TACs under proposed Rule 11-18. This obvious reciprocal relationship between these rules demands that they be addressed comprehensively in one DEIR.

A public agency such as the District may not segment a large project into two or more smaller projects to mask serious environmental consequences. CEQA prohibits such a "piecemeal" approach and requires review of a projects as a whole. CEQA mandates "that environmental considerations do not become submerged by chopping a large project into many little ones –each with a minimal potential impact on the environment-which cumulatively may have disastrous consequences. (Bozung v. Local Agency Formation Commission (1975), 13 Cal.3d 263, 283-284; City of Santhree v. County of San Diego (1989).

Before approving a project, a lead agency must assess the environmental impacts of all reasonable phases of a project. (Laurel Heights Improvement Assn. v. Regents of University of California (1988), 47 Cal.3d 376, 396-397. Clearly, Rules 12-15, 12-16, 11-18, 13-1, the Additional Refinery Rules, and the 2016 Refinery Rules are all part of one "Project" and regulatory action. Therefore, a cumulative analysis is necessary that includes the recently adopted Refinery Project rules (Rules 6-5, 11-10, 8-18, 12-15, and 9-14), proposed regulations (Rule 13-1), and any planned regulations or amendments to regulation (for example, Rules 2-1, 2-2, and 9-1, which are part of the 2017 Rule Development Schedule in District's 2017 Clean Air Plan). See CEQA Guidelines § 15130.

A new NOP and a new draft EIR need to be prepared and recirculated to include all aspects of the Refinery Strategy project and to analyze all potential environmental impacts associated with the complete set of proposed rules directed at refinery sources, which now also now includes proposed Rule 13-1. Therefore, for the foregoing reasons, this DEIR needs to be withdrawn and be expanded and recirculated on a programmatic basis to comprehensively address the cumulative impact of all of the rules, including proposed Rule 13-1.

1.2 The DEIR Fails to Address How these Rules Will Comply with the Federal Clean Air Act, California Air Quality Laws and Other BAAQMD Regulations

The federal Clean Air Act and the analogous air quality laws of the State of California have created a body of regulatory regime which articulates three basic principles: (1) the State and the Air Quality Management Districts ("AQMDs") set applicable emission limits, but do not dictate how the regulated sources will operationally achieve compliance; and (2) as long as the legal emissions limits are met, the State and the AQMDs do not attempt to regulate either the energy sources or the throughput of product in the facility. This regulatory infrastructure which has been created through the state implementation plan ("SIP") process to achieve compliance with federal ambient air quality standards ("NAAQS") and analogous state standards, New Source Review ("NSR") for new and modified sources in non-attainment area, Prevention of Significant Deterioration ("PSD") for new and modified sources in attainment areas, New Source Performance Standards ("NSPS") for new sources, the Title V Major Facility Permit Program ("Title V") for major sources, and the California AB 32 Cap and Trade Program for GHG emissions, the California Toxic Hot Spots Program ("AB 2588") for toxic air contaminants ("TACs") have all been designed to allow major sources such as refineries maximum facility-wide operational flexibility to achieve optimal operational safety, efficiency and sustainability.

This operational safety, flexibility and sustainability is reflected in the conditions and provisions in BAAQMD regulations, Title V permits, permits to operate ("PTOs"), consent agreements with EPA and the BAAQMD, and technical guidance documents issued by EPA, the California Air Resources Board ("ARB"), and the BAAQMD. Proposed Rules 12-16 and 11-18 (particularly Rule 12-16) have the potential for overriding well-established emission limits expressed in Title V permit conditions on which the oil refineries have relied to make operational changes, capital expenditures and achieve facility-wide operational flexibility. California Health and Safety Code Section 40001(d)(3) prohibits the BAAQMD form mandating that specific types of air pollution equipment be installed at a particular facility. However, the DEIR lists the specific air pollution control devices that will be required under these proposed rules. In addition, Health and Safety Code Section 40709 specifically requires that districts with nonattainment areas establish a system by which increases in one facility can be offset by decreases at other facilities. The DEIR should address how Rule 12-16 will comply with that requirement.

For example, the District regulations (Regulation 2 Rule 4) allow emissions banking and offsets. The DEIR should address whether Rule 12-16 will abrogate the right to use emissions reduction credits and offsets.

Furthermore, the DEIR should address whether proposed Rule 12-16 will prevent the use of offsets under the federal and District NSR and PSD programs.

1.3 The DEIR Fails to Address the Lack of District Resources Necessary to Implement Proposed Rule 11-18

As indicated above, the District does not have the staff to implement proposed Rule 11-18 because of the almost universal reach it has to Bay Area sources. This will result in such regulatory delays that the HRA approval process will become virtually unworkable which will greatly disrupt facility planning for refineries and other large facilities. The DEIR must address the environmental and socio-economic impact of the implementation of this regulation.

1.4 The DEIR Fails to Address the Collective Impact of Rules 11-18 and 12-16 of Proposed Rules on the Operational Safety, Flexibility and Sustainability of the Refineries

Following on the previous comment, the DEIR nowhere discusses the collective economic impact of both of these rules on the ability to continue operating the refineries in the Bay Area with the requisite degree of operational safety, flexibility and sustainability. Since the refineries have been singled out for specific targeted regulation over and above the requirements needed to achieve NAAQS and AB 2588 objectives, the DEIR needs to address environmental impacts of singling out refineries for special emission reduction as contrasted with other sources of criteria pollutants, GHG emissions and TACs. For example, contrary to the statements in the DEIR, refineries are not necessarily the major sources of certain pollutants, such as reactive organic gas, NOx, PM 2.5 and SOx.

For example, the DEIR fails to address the fact that the planned caps under Rule 12-16 may cause some refineries to cut production immediately upon the effective date of the rule which may in turn adversely affect the operability of pollution control equipment which may affect controls for TACs.

1.5 The DEIR fails to have a section on environmental effects found not to be significant.

This section, though listed on the Chapter 3 divider page and required by CEQA Section 15128, is missing from the document. The document needs to add this section and the DEIR recirculated so that this can be reviewed.

1.6 The DEIR and Initial Study (IS) used an old Appendix G Checklist and failed to include consideration of Tribal Cultural Resources.

Although this IS was completed in October 2016, the old IS Checklist was used which does not include consideration of tribal cultural resources. This new checklist was prescribed as a result of Assembly Bill 52, passed in 2014, requiring notification to interested tribes for any project requiring CEQA. This analysis should be provided to justify elimination from further consideration including such notifications. As it stands, and bolstered by the lack of inclusion in the Persons Consulted Section of the DEIR, tribes have not had the chance to comment on this CEQA process or proposal. There are prescribed timelines to this notification process that protect tribes' ability to comment and participate before a document is published for draft public review. As a result, even if justifiably eliminated from detailed review in the DEIR, by not complying with the requirements of AB52 before the DEIR review period, the Bay Area Air Quality Management District (BAAQMD) is in violation and must reissue the DEIR after the tribes have had a chance to effectively participate in the process.

1.7 Failure to evaluate Energy Conservation impacts following Appendix F.

Neither the DEIR nor the IS presented an evaluation of energy conservation impacts required under Appendix F of the CEQA Guidelines. The DEIR needs to describe and evaluate the energy consuming equipment and processes that will be used during construction and operation. The document should include the environmental setting that describes existing energy supplies and energy use in the region. This should include the total energy requirements by fuel type and end use including diesel, gasoline, natural gas, and electricity consumption. The analysis should evaluate whether the project would cause wasteful, inefficient, and unnecessary consumption of energy during construction, operation, and/or maintenance, and if it will cause a substantial increase in energy demand and the need for additional energy resources. This section needs to be included and the DEIR recirculated.

1.8 Dismissal of Resource Topics is not justified.

The justification for eliminating various technical resources from detailed review in the DEIR, as provided in the IS, is incomplete in that there are no attempts to identify affected resources. The types of facilities that would be affected are known and the BAAQMD even knows the specific locations, at least in part, of these facilities even if not fully described in the document. However, the IS only speaks to 'typical' or 'general' conditions of such facilities without any consideration of the specific facilities. The mandate of a CEQA document is to work with the best data available at the time and to give fair and consistent consideration when evaluating these resources. This analysis, as it stands, appears to be a basic bare-bones analysis of conditions without a substantiated and referenced analysis. While this can be a good tool to plan a project, after the lead agency determines that an EIR is required, the justifications for elimination and focus in the EIR must be backed by substantial evidence. Specifically, each of these resource discussions that are found to not likely result in a potential for significance should complete a critical analysis of what those resources are at these specific sites rather than assuming conceptual, stereotypical conditions of such an industrial facility.

1.8.1 Elimination of resources from further analysis did not consider specific potential emissions controls when justifying the omission from the detailed analysis in the EIR.

The EIR states that because "…the actual control measures that will be required to reduce emissions, if any, is unknown" that "the EIR evaluates the impacts of potential emissions control measures that could be utilized." The IS does not evaluate potential emissions controls however and therefore does not appear to consider the potential impacts of those controls when eliminating resources from further analysis.

1.8.2 Several dismissed resource topics in the IS concluded the impact was not significant because they lacked detailed information to evaluate the impact on specific facilities.

The resources that concluded that potential impacts could occur, but that adequate information was not available to evaluate the specific impacts, should be revised and mitigation measures included that require a detailed analysis of the potential impact on a project-specific basis. Programmatic level analyses are commonly not able to adequately evaluate all impacts for individual projects. However, these situations typically prescribe mitigation measures that require impacts to be evaluated on individual projects.

1.8.3 The Agriculture and Forestry section should evaluate if distribution infrastructure or other infrastructure and components within public and private right-of-ways potentially be included under the purview of either proposed ruling.

More specifically, if emissions reduction requirements could not be met, should modifications to these components be considered outside the existing footprint of the refinery or toxic air contaminant (TAC) emitting facility? If so, these locations should also be considered and such modifications could potentially affect some of the eliminated resources. Note that this comment applies to several resource areas, not just Agriculture and Forestry Resources.

1.8.4 The biological analysis includes a number of incomplete analyses requiring substantial evidence to justify elimination and should also include regulatory review.

The biological analysis includes a number of incomplete analyses that require substantial evidence to justify elimination and should also include regulatory review. Relevant agencies including California Department of Fish and Wildlife (CDFW), U.S. Fish and Wildlife Service (USFWS), National Oceanic and Atmospheric Administration (NOAA), Regional Water Quality Control Board (RWQCB), Bay Conservation and Development Commission (BCDC), and U.S. Army Corp of Engineers (USACE) have not had the opportunity to review and provide agreement with this level of consideration. This analysis is very conceptual without providing any specific information that relates to locations where possible issues affecting coastal/bay or other wetlands resources may occur. Coastal and wetland resources are found on each of the refinery locations, several related dock facilities, and likely many of the TAC-emitting facilities. There is a cursory elimination of considering migratory patterns as a result of possible modifications and retrofits without any consideration of nesting or migratory bird impacts if stacks are raised or trees/vegetation removed. Wetlands are in fact found on several of these facilities as well. While this might be considered a programmatic level review requiring additional analysis at the time of such a requirement when better information is available, therefore it should be required as a mitigation measure for additional analysis be conducted if applicable. As a result, this analysis is inadequate to allow for effective agency input and inadequate to justify elimination from detailed review in the DEIR.

1.8.5 The cultural analysis is incomplete.

The cultural analysis is incomplete. At a very basic level, the Rule 11-18 discussion only addresses archaeology and does not consider historic structures, while the Rule 12-16 analysis addresses historic structures and not archaeology. Paleontology and human remains are not discussed.

1.8.6 Evaluation in the IS is incomplete related to the impacts on the potential for soil erosion.

Lacking sufficient information regarding the nature of the construction activities that would be associated with implementing control technologies (information missing from the project description), particularly the expected area of earth disturbance, if any, sufficient justification has not been provided for the conclusion that construction and implementation of control technologies would not significantly increase the potential for soil erosion, or for not carrying forward this potential impact into the DEIR. Note that in Section 3.5.4.1.1 of the DEIR, the analysis assumes that an excavation site for a new flue gas treatment (FGT) unit would be approximately 6,000 square feet; this estimate suggests that cumulatively across the project area, there could be a potential for significant erosion during construction activities associated with installation of the control technologies.

1.8.7 The noise analysis is inadequate.

Insufficient information has been provided in the IS to support the conclusion that control technologies would not significantly increase noise levels. Lacking sufficient information regarding the nature of the construction activities that would be associated with implementing control technologies (information missing from the project description) and noise levels associated with operating the control technology equipment, sufficient justification has not been provided for the conclusion that implementing control technologies would not significantly increase noise levels.

1.8.8 The transportation analysis is incomplete.

Because the stated refineries, and likely other TAC emitting facilities, utilize marine vessels, equipment, etc., marine transportation should have been a component of the transportation analysis. Similarly since many facilities utilize rail cars, rail transportation should have been a component of the transportation analysis.

1.8.9 The Utilities and Service Systems analysis is inadequate.

Insufficient information has been provided in the IS to support the conclusion that control technologies would not significantly increase the volume of solid waste generated such that it could exceed landfill capacity. Without sufficient information regarding the nature and volume of solid waste associated with implementing control technologies (information missing from the project description), sufficient justification has not been provided to support the conclusion that implementing control technologies would not significantly increase the amounts of solid waste generated, or that the waste could be addressed by available landfill capacity. Furthermore, information regarding landfill capacity in the project vicinity should be provided in the Setting section.

1.9 The DEIR fails to include the limitations on discussion of environmental impacts.

The DEIR should include a discussion of the limitations on discussion of environmental impacts, specific to those factors not known or beyond the scope of the rule proposal. CEQA Guidelines Section 15127 requires such a discussion for an EIR prepared in connection with the adoption, amendment, or enactment of a plan, policy, or ordinance of a public agency, or the adoption of a resolution making determination. Such cases might be the specific scenarios where such a modification or measure might be needed, specific locations, or extent of authority to prescribe such an action. Resolutions should then be set to base the analysis with the intent to make this DEIR a useful and objective analysis of potential impacts with substantiated resource elimination, alternative elimination, and findings.

1.10 The IS references were inadequate.

This analysis was cursory and incomplete on many levels and inadequate to identify potential impacts or to justify elimination of specific resources from detailed review. The fact that only three references were used in the development of the IS further demonstrates the lack of intent to comply with the spirit of CEQA. This analysis was cursory and incomplete on many levels and inadequate to identify potential impacts or to justify elimination of specific resources from detailed review. This analysis should be revised with citable sources and the DEIR should be recirculated considering all CEQA-prescribed resource sections.

1.11 The List of Preparers and Agencies Consulted is deficient.

The List of Agencies Consulted is inconsistent with the requirements of CEQA Section 15129. Section 15129 of the CEQA Guidelines requires that "The EIR shall identify all federal, state, or local agencies, other organizations, and private individuals consulted in preparing the draft EIR, and the persons, firm, or agency preparing draft EIR by contract or other authorization." This section of the DEIR provides a list of names, but does not provide any affiliation or interest rationale to offer insight into the consultation value to the process.

The List of Preparers is inconsistent with the requirements of CEQA Section 15129. Per Section 15129 of the CEQA Guidelines and as a matter of practice, the list of preparers must clearly identify all staff, agencies, and organizations who prepared the EIR. The list must indicate the name, affiliation, and a very brief explanation of each individual's role in the preparation of the EIR. This section serves as a basis of qualification to prepare such an analysis.

2 THE PROJECT DESCRIPTION IS INADEQUATE

2.1 The justification for eliminating various technical resources from detailed review in the DEIR, as provided in the IS, is incomplete in that the project description used as a basis of analysis in the initial study did not provide detail as to what measures and activities might take place if emissions reductions cannot be met.

The justification for eliminating various technical resources from detailed review in the DEIR, as provided in the IS, is incomplete in that the project description that was used as a basis of analysis in the initial study did not describe what measures and activities might take place if emissions reductions cannot be met. Descriptions should include operational changes; equipment type and size; location where they could typically be installed; the duration of construction activities; the nature and extent of earth disturbance associated with their installation; hazardous materials associated with their operation; waste (nature and quantity) that would be generated from their use; how that waste would be disposed of; resulting noise levels from control technologies; energy demands; etc.

Several of the analyses raised possible types of activities that might occur including stack raising, ground disturbance, and other activities that were generally dismissed without substantive detail as to why. The fact that these examples were provided, be it only in isolated resource discussions, but without any kind of relation to the specific type of facility, placement, etc. appears to skew the analysis to justify the conclusion before substantiating the analysis. While these types of modifications might be minor in the end and might not result in measurable impacts to these resources, the analysis does not adequately, completely, or consistently define the project being analyzed in the IS, and therefore this IS cannot be reasonable relied on to justify the ultimate focus of the DEIR. It is recommended that a complete IS be prepared or otherwise, that all resources be carried forward in the DEIR before recirculation. Likewise, the

DEIR should also discuss the specific types of modifications that might be required to fully justify its conclusions.

2.2 *The Project Description failed to adequately characterize facilities that may be impacted by the proposed rules.*

2.2.1 The DEIR does not include a full list of affected facilities.

Several emission sources are not listed in Section 1.3.3.1 as affected by Regulation 11-18. For instance, San Joaquin Valley Air Pollution Control District (SJVAPCD) has demonstrated that a typical hospital would have trouble meeting the risk thresholds established in Regulation 11-18 (SJVAPCD 2015. *Final Draft Staff Report with Appendices for Update to District's Risk Management Policy to Address OEHHA's Revised Risk Assessment Guidance Document* p. 21). Numerous small business owners would be impacted due to backup emergency generators that may exceed the risk thresholds of Regulation 11-18. Staff estimates that this rule could impact hundreds of facilities and several have not yet been engaged on this issue or were only recently aware of the potential impacts.

2.2.2 The DEIR failed to convey the location of facilities impacted.

The DEIR was limited in its use of figures to convey the geographic scope of facilities impacted by the proposed rules. Given the specific list of facilities covered by each proposed ruling, one could assume that the lack of mapping might be intentionally trying to generalize or suppress the potential impacts of these rulings. As a readability tool, which is critical and heavily encouraged in the CEQA process, a figure showing each area of coverage would offer a very easy tool to understand the affected facilities. Furthermore, offering similar figures among the alternatives considered would be helpful. Understanding that sensitive information is included, these maps could be developed in a way to show data without compromising facility standings.

2.2.3 The DEIR fails to describe major category of sources at refineries.

In characterizing the different types of emission sources at a refinery, the DEIR fails to describe process heaters and boilers that can potentially emit substantial amounts of criteria pollutants and TACs contained in the natural gas or refinery fuel gas. In addition, other sources such as sulfur recovery plants that are major sources of sulfur oxides (SOx) emissions are not described.

2.2.4 The DEIR fails to describe major category of sources at facilities.

In characterizing the different types of emission sources at manufacturing and chemical facilities, the DEIR fails to describe process heaters and boilers that can potentially emit substantial amounts of criteria pollutants and TACs contained in the natural gas. In addition, the DEIR fails to describe the TACs associated with pollution control devices such as TACs from thermal oxidizers and selective catalytic reformers (SCRs).

2.2.5 The DEIR is inconsistent in its list of potential pollution control technologies.

The several sections of the DEIR in Chapter 3 contain pollution control equipment not adequately described in the project description section. High efficiency particulate air (HEPA) filters as pollution control devices have not been previously mentioned in the DEIR and are mentioned in several sections of Chapter 3. The project description should be modified to include a discussion of HEPA filters since these are pollution control devices evaluated in several resource topics as potentially having impacts. For instance, the Hazards section requires mitigation measures to address some of the hazards associated with HEPA filters.

2.2.6 The DEIR does not adequately describe potential control technologies that may be used to comply with Regulation 11-18 and 12-16.

The DEIR fails to adequately describe potential control technologies that may be used to comply with Regulation 11-18. For example typical efficiency ranges that would be expected should be provided in Table 2.5-2. In addition several viable technologies are excluded. For example, in similar rule making, the South Coast Air Quality Management District (SCAQMD) included HEPA filters, dry scrubbers, and fixed or moving bed regenerative solvent reclaimers as potential control technologies (SCAQMD 2016. *Final Environmental Assessment for PARs 307.1, 1402, 1402 & Associated Rule 1402v Guidance Documents.* SCAQMD NO 160817CC SCH No. 2016081057). In addition, the DEIR did not discuss that a combination of control devices may be needed to adequately control the criteria and TAC emissions of a source.

The DEIR does not describe the range of control technologies for regulation 11-18 that are described in Table 2.5-3 for ways refineries could lower emissions.

The description of basic wet gas scrubber principles in Section 2.5.2.7 does not provide relevant information such as information that scrubbers in general, and especially high efficiency scrubbers, are very energy intensive and generate a liquid waste stream often requiring additional treatment. Note that Table 2.5-3 inconsistently lists wet gas scrubbers as an SO_2 control technology, but not $PM_{2.5}$ control technology for FCCU and FCC process units, while it is listed as controlling both types of pollutants for application to sulfur recovery units.

The description of the Claus unit converters and condensers is noted to remove as much as 95 percent of the sulfur in incoming gas streams. Subsequent paragraphs describe tail gas treating processes. It should be noted that all Bay Area refineries are required to use tail gas treating units and that the combined efficiency is well above 99+ percent sulfur removal.

2.2.7 The DEIR does not adequately describe control technologies for GHG emission reductions.

The DEIR does not clearly describe greenhouse gas (GHG) emission reduction strategies. The strategies for GHG emission reductions should be fully described and added to Table 2.5-3 of the DEIR.

2.2.8 The DEIR and Regulation 11-18 do not include an accurate representation of toxic emission inventories for facilities.

Providing an accurate and detailed toxic emission inventory is not currently a requirement for many facilities that will be covered by Regulation 11-18. BAAQMD currently provides an estimate of toxic emissions for intermediate facilities as required under AB2588. This inventory is not based on detailed information sufficient to produce an accurate annual emission inventory. Regulation 11-18 does not require a detailed toxic emission inventory to be provided for prioritization purposes. The regulation only specifies this upon request to the facility to provide information necessary to complete a Health Risk Assessment (HRA).

2.3 The project objectives are inadequate.

A project objective to provide accurate and representative data should be added. Objectives that serve to provide the public the opportunity to comment on draft HRAs and risk reduction plans are clearly stated. Also not stated and addressed in the rule is the objective to ensure that the source's emissions and operating conditions reflect actual and representative rates. An objective that provides the facility the opportunity to verify and confirm the accuracy of the use of best available data and review/confirm results should be added to the rule and project objections. Objectives could be expanded to involve affected businesses as stakeholders.

2.3.1 The project objective relating to an emission cap is flawed.

It has not been demonstrated that an emission cap would necessarily reduce the emission intensity of the production of transportation fuels. One of the project objectives of Rule 12-16 is to prevent any significant increase in the emission intensity of the production of transportation fuels. It is not clear that this objective will always be achieved by instituting emission caps. For instance, installing pollution control devices to reduce emissions of a criteria pollutant may result in an increase in direct or indirect GHG emissions or increases in other criteria pollutants; therefore there could potentially be an increase in emission intensity of the production of transportation fuels with respect to those pollutants. Additionally, the emission intensity per barrel of transportation fuel may increase if a facility must curtail production on some sources at the facility in order to meet the emission cap limits. This would result in the refinery not operating as efficiently and thus may produce less transportation fuel per ton of pollutant. A refinery is optimized to be most efficient when its source units are operating near full capacity. The project description states that an exceedance of a cap would be considered a violation over the entire calendar year. An emissions cap should not be considered as exceeded before the date that the limit was exceeded.

2.3.2 The emission cap of 7 percent allowance is unsubstantiated.

A limit is proposed for emission caps including a 7 percent threshold allowance or threshold factor intended to account for year-to-year variations. Is there information to support that 7 percent is appropriate to capture year-to-year variation? A reference should be provided that points to this information. The DEIR did not adequately address the impact of this 7 percent allowance on future socioeconomic impacts, impacts from decreased operational flexibility and impacts from leakage.

2.3.3 The project objective that discourages investment in new refinery equipment is flawed.

Discouraging investment in new refinery equipment that would lead to increased emissions of GHG, particulate matter (PM), nitrogen oxides (NOx), or SOx does not consider that some new equipment may substantially decrease one or more of these pollutants, while having some increases in other pollutants. This objective may result in the inability to substantially reduce a specific pollutant since the new equipment may have increases in another pollutant. Little flexibility is provided to balance tradeoffs in equipment and the potential pollution increases or decreases that may occur. For instance, installing equipment to reduce SOx emissions could result in substantial increases in GHG emissions. There is no mechanism to provide a balance of emission reductions between pollutants such that while the new equipment may have some increases, it may overall cause a decrease across pollutants. This objective also fails to consider the safety aspect of not encouraging newer and safer equipment to be installed. The discouragement from investing in new refinery equipment does not encourage improvement in process efficiencies due to new technologies being discovered. New equipment with new technology has the largest potential to dramatically improve carbon intensity and overall refining efficiency.

2.3.4 The DEIR objectives refer to transportation fuels, but do not discuss other refined products at a refinery.

The DEIR objectives repeatedly discuss transportation fuel efficiencies. The definition of transportation fuels is not defined. In addition, Regulation 12-16 does not describe how it will determine emissions and efficiency for refineries that produce non-transportation products such as lubrication oils and petrochemical feed stocks. For instance, several refineries have lubrication plants, carbon plants, and asphalt plants. It is unclear how these are being considered for the refineries in particular since not all refineries have these sources and plants.

2.4 The DEIR fails to give a comprehensive list of chemicals and their effects that would be addressed with this rule.

The DEIR only discusses in detail four types of pollutants targeted for reduction under Regulation 11-18, benzene, 1,3-butadiene, polycyclic aromatic hydrocarbons (PAHS), and diesel particulate matter (DPM). Other pollutants that should be discussed that were mentioned in the October 2016 BAAQMD draft staff report and Table 2.5-1 of the DEIR include formaldehyde, metals, hydrogen sulfide, hydrogen chloride, vinyl chloride, ammonia, ethyl benzene, and any other TACs listed by Office of Environmental Health Hazard Assessment (OEHHA) and BAAQMD Regulation 2-5.

2.5 The DEIR mentions that emission limits would change if the method of monitoring or estimating emissions changes, but fails to describe the mechanisms.

The specific mechanism for determining methodology changes is unclear. This is complicated by the fact that a detailed methodology for the criteria pollutant emissions has not been adequately described. It is unclear that that methodology used as a basis for establishing the proposed emission caps has been consistently applied to all applicable facilities. In addition, it is unclear if this is the same methodology that is being required for facility use under Regulation 12-15. Since it is likely that Regulation 12-15 information will form the basis of compliance with Regulation 12-16, it is imperative that any discrepancies with the methodology be disclosed including emission factors and the range of sources included. Some key anticipated changes in methodology that should be addressed include startup and shutdown operations, permanently removed equipment, and inclusion of condensable particulate matter.

Furthermore, it is not clear on the permitting process for updating the air operating permits for refineries subject to these regulations, including any Title V requirements for public comment.

2.6 The DEIR is confusing as it fails to adequately define qualifying terms.

The IS refers to *major* sources, *significant* contributions, *substantial* impacts, and the like. Without an objective definition of these terms, the analysis is unsubstantiated and further appears biased to justify the conclusion without a thoughtful analysis.

The DEIR does not adequately define key terminology that is part of the proposed rules and important for understanding the analysis. This includes the regulatory definition of a “major source”, “significant source of TAC”, “significant risk threshold”, and “risk action levels”. The term “significant source” is used in different contexts within the DEIR. This needs to be clarified to ensure that a consistent definition and context are used throughout the DEIR.

2.7 The DEIR does not describe the calculation of prioritization score which is a key determination of which facilities are impacted by the proposed rules.

The DEIR should provide a citation or include a detailed description of the prioritization score methodology that will be used to initiate the Regulation 11-18 process.

2.8 The requirement to install TBARCT on all significant TAC sources is not clear, thus its impacts are not able to be determined.

The criteria for 'significant sources of TAC' is defined, but does not clarify whether the criteria applies to the risk at any receptor or only those receptors that experience risk above the facility-wide threshold. If interpreted at any receptor, TBARCT could apply to many more operations and equipment that might not affect the goal of reducing facility health impacts to below 10 in a million cancer risk or hazard index of 1.0. The impact of installing TBARCT on these sources that do not affect the highest overall facility risks should be evaluated.

2.9 Options for risk reduction does not include TBARCT alternative for a source to be below significant risk threshold.

The project description in the DEIR on Rule 11-18 in section 2.1.2, only presents the option of install TBARCT on sources if a facility is above a specified risk threshold. Section 11-18-301.2.2 also allows for a source to demonstrate that it is not above the significant risk thresholds set forth in Section 11-18-217. The significant risk thresholds in section 11-18-217 are a cancer risk of 1.0 in a million; or a chronic HI of 0.20 or an acute HI of 0.2. The project description should be modified to define clearly what a significant source of TAC emissions is at the facility.

The DEIR needs to clearly indicate that even after all sources implement TBARCT, the facility may still result in significant risk levels such as a cancer risk above 10 in a million, but that a facility would not have to take any further actions under Regulation 11-18 since all sources meet TBARCT.

2.10 The context and relative amount of risk of these TAC pollutants should be illustrated to support rationale for phasing implementation.

Recent BAAQMD presentations provide detail showing the relative amount of risk by pollutant. These presentations show that the largest overall contributor to risk in the Bay Area is DPM as well as components of gasoline fuel. However, sources of DPM and gasoline stations are prioritized for phases 3 and 4 of implementation. The rationale for prioritizing sources should be explained further.

2.11 The effectiveness of the project objectives is minimal since it does not capture the dominant sources of TACs in the region.

The DEIR correctly states that BAAQMD has jurisdiction over stationary sources, as opposed to mobile sources. The DEIR distinguishes that DPM emissions sources mainly include mobile sources, such as heavy-duty trucks, buses, construction equipment, locomotives, and ships, but also stationary sources such as stationary diesel engines and backup generators. Since BAAQMD lacks jurisdiction of mobile sources, the HRAs should include stationary diesel engines and generators, but not include ships, locomotives and construction equipment. This would be consistent with the types of stationary sources evaluated under AB2588 HRAs. TAC emission reductions for mobile sources are regulated by CARB under Air Toxic Control Measures (ATCMs).

2.12 The draft rule and DEIR do not clarify how it will involve the facility in the process of refining the emission inventory.

Conducting an HRA for a complex facility is complicated and involves acquisition of multitudes of data to establish source characteristics, operations, emission rates, measurements and representative factors. Emission rates in inventories include estimates which can sometimes include worst-case or conservative assumptions when measurements or accurate determination is not readily available or feasible. Estimates can be subject to refinement if determined to be a significant contributor to overall risk results. Important factors are not often apparent until after running an initial screening HRA. The development of an HRA is most often an iterative process and involves the knowledge of subject matter experts, operations personnel and sometimes further investigation or testing. It is important that the BAAQMD reviews its preliminary work with knowledgeable facility representatives to ensure that adequate information and estimates have been provided and that sources are characterized appropriately. Neither the rule nor the DEIR describe the process BAAQMD will use to review its preliminary assessments and results with facility representatives to ensure they are accurate. Real risk reduction will be difficult for facilities to achieve if the basis for the HRA is flawed.

Proposed Rule 11-18-401 requires submission of any information required to conduct an HRA within 30 days to BAAQMD upon notification. Without advance notification to the facility of this requirement specifically applying to them, it will be difficult for facilities to provide the detail and quality of information required to prepare a meaningful HRA in a 30 day period. Some important information may not be readily available and may require testing or research to ensure accuracy. More importantly, it is often not possible to know what emission estimate or measurement data will be adequate for the HRA without conducting an initial screening HRA and identifying the key inputs and impacts to verify the input data. It is an iterative process for most facilities. This data collection and validation step is not contemplated in the proposed rule language. The BAAQMD should consider following timing and facility involvement similar to other regulations such as AB2588 and SCAQMD Rule 1402. BAAQMD should revise its timeframe for submittal of data and validation of the HRA results. This should be addressed to ensure meaningful HRAs are prepared.

The exclusion of the facility from the HRA process makes no sense in ensuring transparency between the facility, BAAQMD and the public. The facility has unique knowledge about its facility and operations which are difficult to fully capture in a data request. This is even more confusing for the HRA process with the facility given that BAAQMD intends to hire 3rd party vendors who are even further removed from the facility and BAAQMD. The use of 3rd party vendors rather than reliance on the facility knowledge adds a further layer of decreased transparency and insurance that information is adequately considered and implemented in the HRA.

2.13 The DEIR limited its analysis of secondary impacts only to installing air pollution control equipment to comply with the risk reduction plan requirements of rule 11-18 and emission limits under 12-16.

The NOP/IS for the proposed rule identified that installing APC technologies could cause significant adverse environmental impacts. The DEIR limited its analysis of secondary impacts only to installing APC. To comply with the risk reduction plan requirements of rule 11-18 and emission limits under 12-16, the DEIR suggests that one likely measure taken by facilities would be to reduce operations, thus reducing fuel availability in the local area. The DEIR does not contemplate the potential gap in limiting fuel production versus fuel supply trends and projections, and where the fuel would come from to make up the gap. The fuel produced and shipped from locations other than the local bay area refineries, and the environmental impacts of supplying this fuel should be considered as they would be potentially significant adverse environmental impacts.

2.14 The DEIR does not provide references for its assertion of the refinery average utilization rates.

The DEIR Project Description fails to provide adequate citation for its assertion that annual average utilization is 80-87 percent. It does also not describe if specific facilities had lower than typical utilizations due to various economic and processing issues during this base period which may have caused an individual facility to have lower than average utilization. All types of economic and processing issues may not have occurred in the past and/or some may not be anticipated to occur in the future.

3 INADEQUATE REGULATORY BACKGROUND AND ENVIRONMENTAL SETTINGS

3.1 Most resource sections only include a general boilerplate statement of the regulatory framework of each given resource area.

If these documents were not reviewed, and cited, the statement is not useful to the analysis and should not be included. If statements of the regulatory framework that are not appropriately cited are not included, the validity of the analysis is limited. As an example, though certainly not the only example, Land Use and Planning refers to "the City and/or County General Plans" but does not include any reference to these. As a result, in the analysis of whether the proposed rulings conflict with any applicable land use plan, policy, or regulation, there is no basis for comparison or judgement. This conclusion is unsubstantiated without consideration of these plans or a citable analysis.

4 DEFICIENCIES WITH AIR QUALITY ANALYSIS

4.1 The DEIR Table 3.2-1 is missing some AAQS.

The DEIR Table 3.2-1 does not show the state AAQS for sulfates, hydrogen sulfide and vinyl chloride.

4.2 The DEIR is misleading by providing a 70-year cancer risk in the air quality setting section while intending to utilize a 30-year cancer risk for implementation of regulation 11-18.

The DEIR is misleading by providing a 70-year cancer risk in the air quality setting section while intending to utilize a 30-year cancer risk for implementation of regulation 11-18. The DEIR setting section should be revised to show the cancer risk on an equivalent basis as the Regulation 11-18 will use in order to adequately characterize the environmental setting and background to establish baseline conditions.

4.3 The air toxics emission inventory used in the air quality setting is outdated.

The air toxics emission inventory used in the air quality setting is outdated. The information referenced is from 2010 and is more than 6 years out of date. This should be updated with more recent information in particular as this is important in characterizing the baseline used to evaluate regulation 11-18.

4.4 *The ambient monitoring network should describe the location of the stations or provide a map indicating their locations.*

The ambient monitoring network should describe the location of the stations or provide a map indicating their locations. It should also indicate at which station the maximum concentration of TACs listed in Table 3.2-5 occurred.

4.5 *The construction emissions significance criteria are provided with no citation of substantial evidence.*

The construction emissions significance criteria are provided with no citation of substantial evidence. The DEIR presents construction emission thresholds of significance for air quality without providing citations or discussion on how these thresholds were developed. The DEIR mentions the BAAQMD's 1999 significance threshold as having no significance threshold for construction emissions. They do not provide adequate substantial evidence describing why they believe significance thresholds provided in Table 3.2-7 represent a level above which a project's individual emissions would result in a considerable contribution to existing non-attainment air quality conditions.

4.6 *The construction estimates for installing pollution control devices is not realistic.*

Installing a wet gas scrubber at a refinery is a major capital project taking years in planning, design and construction, which may not be feasible to implement in a timely fashion to allow a refinery flexibility to operate according to market demand for products. The BAAQMD points out that installation of a wet gas scrubber is a possible necessity in order for refineries to fully utilize the capacity of their plant. The BAAQMD assumes that the construction completion a wet gas scrubber, from concept stage through construction could take months or years. Experience shows that concept, funding, design, permitting and construction of these units take several years and are very expensive units to purchase and operate. By capping refinery emissions and utilization of each local refinery, Rule 12-16 could eliminate current flexibility for the refineries which combined may not be able to meet the local demand for fuels in the event of a long-term temporary loss of production at any one of the facilities or within the California fuels market.

4.7 *The emission inventory used for setting emissions caps for Regulation 12-16 is flawed.*

BAAQMD should perform an audit of the data in CEIDARS and compare to actual reported historical plant direct measured emissions (e.g. CEMS) and cite the specific emission factor calculated data. The CEIDARS data is inaccurate due to the use of general emission factors in emission calculations. It is strongly suggested that the emission caps should be revised using site-specific data before proposing a cap. Furthermore, a five-year snapshot of emissions does not accurately depict what could happen to a facility in any given year and does not reflect that the economy and demand for transportation fuels has not fully recovered from the recession.

The definition of the emission inventory in rule 12-15 includes cargo carriers, yet the standards proposed for Regulation 12-16 fails to include baseline numbers for cargo carriers as well as several other source categories. These may also be outside the authority of the BAAQMD to regulate as part of the refinery. The cargo carriers are generally not owned or operated by the refineries and therefore the refineries do not have any specific control over the operation of the cargo carriers

4.8 Regulation 12-16 is in conflict with existing State and Federal approved permit programming rules.

There is no justification for imposing a fixed numeric cap on petroleum refining facilities; it is fundamentally inconsistent with the State's cap and trade program. District rules must be consistent and in harmony with existing State law and not be arbitrary, capricious, or without a reasonable or rational basis. Thus the impact statement that there is no significant impact or conflict with existing rules is inaccurate. This impact analysis needs to be revised and the DEIR recirculated.

4.9 The regulatory basis and context for Regulation 11-18 has not been adequately described in the DEIR.

The DEIR needs to clarify authority for 11-18 and identify the relevant state and federal codes, particularly those sections related to establishing TBARCT. The DEIR needs to clearly state that this is not based on BAAQMD's authority under AB2588. The DEIR needs to explain how the process would work in practice for applying TBACT and TBARCT in accordance with NSR permits and clarify whether a significant source would need to apply TBARCT, TBACT, or both. Prior to adoption of the rule, BAAQMD needs to develop a process to make TBARCT determinations and in defining TBARCT for specific sources. TBARCT should be defined as part of the 11-18 rulemaking. Note that the current unavailability of TBARCT guidelines discourages early actions to reduce risk. BAAQMD's intent is that TBARCT can be no less stringent than an existing source MACT standard. However, TBARCT cannot and should not be defined in reference to new source MACT standards, which may be unachievable, infeasible, or prohibitively costly for existing sources subject to TBACT. Where post-project actual emissions are projected to be lower than pre-project actual emissions, that project should be exempt from Rule 2-5 TBACT requirements.

4.10 The DEIR relies on deferred mitigation measures which are not allowed under CEQA.

The mitigation measures to address the significant NOx emissions are deferred mitigation which is not allowed under CEQA. The mitigation measures while presenting an array of options, fail to provide a minimum performance standard which would be required for the overall NOx mitigation strategy to achieve. The NOx mitigation measures need to be revised and the DEIR recirculated.

4.11 The DEIR failed to evaluate exposure to sensitive receptors.

The DEIR needs to be revised and recirculated to specifically evaluate the impact of exposing sensitive receptors to air pollutants. While Regulation 11-18 is aimed at reducing and characterizing toxic air containments released from facilities, the DEIR did not reach an impact determination. In addition, these health impacts need to be determined if they would also be cumulatively considerable given the ambient levels of toxic air contaminants from all sources in particular mobile sources.

4.12 The DEIR failed to evaluate odor impacts.

The DEIR did not present significance determination associated with odor impacts in the DEIR. Construction activities such as fossil-fueled equipment and odors from soil disturbances can occur. The analysis should require that odors be minimized and piles of organic matter in soil be covered to reduce odors.

5 DEFICIENCIES WITH GREENHOUSE GAS ANALYSIS

5.1 It is unclear how the proposed GHG emission cap is consistent with state regulations, plans and policies for GHG emissions.

The DEIR says that there is a potential conflict with the state's cap and trade program since this would not allow a facility to participate in the cap and trade program to its full extent by purchasing offsets above the BAAQMD emission cap without being in violation of the BAAQMD regulation. This essentially creates a new legal limit on GHG emissions in conflict with state regulations and does not reflect the spirit of the cap and trade program which allows for reductions in GHG emissions to occur where most economically beneficial while still allowing for operational flexibility across facilities. Furthermore, the DEIR fails to address CARB's latest scoping plan and any plans to reach reduction levels in GHG emissions beyond 2020. The DEIR does not discuss this regulation and the potential for leakage in the context of the Low Carbon Fuel Standard. The DEIR needs to more adequately address the state regulations, plans and policies and properly determine the impact of this regulation in the context of these regulations and Scoping Plan.

5.2 The GHG emission significance threshold is not based on substantial evidence.

The GHG emission significance threshold is not adequately based on substantial evidence. The DEIR suggests a "no net increase in emissions" thresholds as appropriate for overall air quality plans, but fails to provide proper justification that there are sufficient alternative measures in its overall air quality plan to ensure that any GHG emission increases as a result of the proposed rules would be adequately offset by other measures.

In addition, the district mentions a 10,000 metric ton of carbon dioxide equivalent (CO2e) emissions threshold but fails to provide substantial evidence indicating that this is sufficient to not have a cumulatively considerable impact on global climate change. BAAQMD also references a document that they no longer recommend for use as a general measure of a project's significant impact.[1]

Furthermore, this 10,000 metric ton CO2e threshold or the "no net increase in emissions" do not discuss how they will ensure that the state laws, plans, and policies requiring reductions below 1990 levels with interim goals in 2020, 2030 and 2050 will be achieved. Thus these thresholds of significance are inadequate. The DEIR needs to be revised to use significance thresholds that are based on substantial evidence and the DEIR recirculated.

5.3 GHG emission inventory excludes indirect emissions which is inconsistent with previous guidance.

The GHG emission inventory does not adequately include all indirect GHG emissions which is consistent with BAAQMD's guidance on methodologies and included in GHG emission inventory models used throughout the state. The GHG emission inventory did not address the indirect GHG emissions associated with water use, water treatment, and solid waste disposal. The GHG emission inventory failed to capture the extent of electricity use increase associated with addition of pollution control devices. Most pollution control devices use electricity to run control systems, power blowers, or perform mechanical functions. In particular a heavy user of electricity such as an ESP has not been included in the emission inventory. These omissions have the potential to change the significance conclusion. Therefore the GHG emission inventory should be revised and the DEIR recirculated.

5.4 The GHG analysis dismisses accounting for changes in source of gasoline supply as being speculative when adequate data is readily available.

The California Air Resources Board (CARB) has developed a sophisticated model for evaluating emissions associated with automobile use in California. This model is called the EMFAC2014. It includes not only estimates of air emissions and fuel use from motor vehicles in California, but it includes estimates of economic growth in motor vehicle use. This estimate from CARB as well as other emission models that have estimates of future economic growth in fuel consumption should be used to provide an analysis of the potential impacts associated with increased demand for transportation fuels in California. In addition, the Low Carbon Fuel Standard provides calculation methodologies to estimate the GHG emissions associated with supplying fuels from other sources. The DEIR needs to be revised to account for the shift in GHG emissions globally if the emission caps of Regulation 12-16 prevent local refineries from being able to supply transportation fuels predicted by increased demand.

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[1] (http://www.baaqmd.gov/plans-and-climate/california-environmental-quality-act-ceqa/updated-ceqa-guidelines)

5.5 The conclusion that GHG impacts from 12-16 are less than significant is only an assumption and not based on substantial evidence presented in the DEIR.

Given the importance of the objective of protecting the climate, the analysis of the actual impact of 12-16 on increasing or reducing GHG emissions should be better studied. Measures to reduce emissions below caps for criteria pollutants can involve controls that increase GHG. Another example, if a reduction in demand for fuels does not occur, the caps proposed by this rule could impose limitations on producing fuels locally, resulting in shipment of fuels from other locations with less efficient processes to this local market which could increase globally GHG emissions. The likelihood of this circumstance should be better understood to fully address and conclude upon GHG impacts.

6 DEFICIENCIES WITH HAZARDS AND HAZARDOUS MATERIALS

6.1 The hazards analysis failed to consider the presence and potential disturbance of asbestos containing materials and/or lead based paint.

The DEIR needs to evaluate the impact of disturbing areas containing asbestos and/or lead based paint. It is likely that several industrial facilities that have been in operation a long time will have asbestos containing material or lead based paint. This needs to be evaluated and proper mitigation measures to address these hazards needs to be included in the DEIR.

6.2 This section failed to address impacts for facilities that are on known contaminated sites.

The DEIR needs to be revised and mitigation measures implemented to address potential disturbances of areas known to be contaminated. This should include proper methods to deal with these hazards to prevent further contamination.

6.3 This section does not acknowledge possible fuel transportation hazards.

If a reduction in demand for fuels does not occur, the caps proposed by this rule could impose limitations on producing fuels locally, resulting in shipment of fuels from other locations and potential increase in hazards from materials transport. The potential likelihood of this circumstance and impacts should be better understood.

6.4 Evaluation in the IS related to impacts to air traffic safety is incomplete.

Elsewhere in the Initial Study (page 2-1), reference is made to increasing stack heights as a control technology. The impact evaluation should consider whether this facility modification (or other control technologies that involve vertical structures) could result in impacts to air traffic safety. Note that this option is also mentioned in passing in the DEIR (for example on pages 2-23, 4-9, 4-10), but is not discussed as a control technology in either Section 2.5.2 (for Rule 11-18) or 2.5.3 (for Rule 12-16).

6.5 The hazard analysis in the DEIR is incomplete in analysis of potential hazards associated with control devices.

Table 3.4-1 of the DEIR indicates that there would be a potential hazard associated with (1) the increased use of caustic or lime for the LoTox technology, and (2) the catalysts used for selective oxidation catalyst - neither hazard is evaluated further in the DEIR, and no justification is provided for this omission.

In addition, the impact evaluation focuses on hazardous materials used by control equipment and hazards associated with equipment operation. The discussion should be expanded to address hazards associated with the waste generated by equipment operation, and the handling of that waste.

7 DEFICIENCES WITH HYDROLOGY AND WATER QUALITY

7.1 The basis for the water demand significance threshold is not explained.

The DEIR states that impacts of the project on water demand would be considered significant if the project would use more than 262,820 gallons per day of potable water. The basis of this number should be provided in the DEIR. In addition, references to this threshold should be consistent throughout the report. On page 3.5-20, the threshold is referenced as being 263,000 gallons per day.

7.2 The evaluation of impacts to water quality is incomplete.

As written, the impact evaluation assumes that wastewater from a wet scrubber is "typically [underlined for emphasis] treated and recycled to minimize water demand and wastewater generated." Similarly, the discussion notes that wastewater from a wet gas scrubber "can" be treated and recycled. If there are instances in which this is not done, the analysis should (1) acknowledge that wastewater quantity could increase and its characteristics could change due to operation of these types of equipment under Rules 11-18 and 12-16, and (2) assess the potential for impacts to water quality.

7.3 Insufficient information has been provided in the IS to support the conclusion that construction activities associated with control technologies would be limited in size, thus limiting the potential for increases in runoff.

Without having been provided sufficient information regarding the nature of the construction activities that would be associated with implementation of control technologies (information missing from the project description), it is not clear that construction areas would be limited in size. Sufficient justification has not been provided for the conclusion that construction activities would not contribute substantially to runoff. Note that in Section 3.5.4.1.1 of the DEIR, the analysis assumes that an excavation site for a new FGT unit installation would be approximately

6,000 square feet, and that a total peak of 18,000 gallons of water would be applied each day during construction. This hypothetical scenario suggests the potential for significant runoff.

7.4 The scenario related to water usage for dust suppression was not fully substantiated, and the water application rates were unrealistic.

The impact evaluation assumes that the typical control system would require approximately 6,000 square feet of space (using an FGT unit as an example of one of the largest expected). Because information regarding control technology unit sizes/construction footprints were not provided in the project description, this assumption could not be corroborated.

For assessing the water demand for dust suppression during construction, the impact evaluation assumed that one gallon of water would be applied to each square foot of exposed soil, up to three times a day. This assumption appears over conservative for the purpose of estimating water usage for dust suppression; an application rate of this magnitude would likely result in significant runoff. It is suggested that the discussion in Section 3.5.4.1.1 be clarified to note that the estimates used in the analysis are overly conservative for the purpose of estimating water usage and unlikely to occur in practice.

7.5 The format of this section is not consistent with the other impact assessment sections.

Specifically, the Hydrology and Water Quality section contains a section (3.5.6) entitled Mitigation Monitoring Requirements. It is unclear why this section contains this section, when none of the other resource discussion do. If this section is to be retained, we suggest that the mitigation measures listed in Table 3.5-2 be revised to reflect the actual wording in the MMs listed in Section 3.5.5. The wording for HWQ-2 is particularly confusing. The entry for "Methodology" in Table 3.5-2 refers to two mitigation measures that are not associated with hydrology and water quality, and should be revised accordingly.

8 DEFICIENCIES WITH CUMULATIVE IMPACTS

8.1 The DEIR failed to adequately evaluate the project impact with respect to the cumulative setting of past, present, and future projects.

The DEIR failed to adequately describe the cumulative setting and characterize the past, present, and future projects that need to be considered with the proposed project to evaluate cumulative impacts.

8.2 The DEIR failed to take into account the impact of projected regional growth and how this would influence the impacts of the proposed Regulations.

The DEIR failed to consider the regional growth which may require additional need for goods and materials provided by refineries and other facilities subject to the proposed regulations. The ability for existing facilities to grow to meet this increased demand or for these goods and services to be provided outside of the region needs to be discussed for each resource topic. For instance, there will likely be an increased demand for transportation fuel that may require local refineries to increase capacity and/or these be supplied by facilities outside the region. Another example is that increased population growth may require expanded or new office buildings, hospitals, and gasoline refueling stations which all will be impacted by Regulation 11-18 especially those areas located in dense population centers where sensitive receptors are located adjacent to these facilities.

8.3 The DEIR failed to adequately characterize the cross-media environmental impacts and potential unintended consequences in particular leakage given the breadth of regulations the BAAQMD intends to enact on the refineries.

Deficiencies in regulations and potential unintended consequences become evident when viewed more holistically. BAAQMD needs to address cross-media impacts in the context of the breadth of regulations proposed for refineries. The DEIR needs to evaluate Regulations 11-18 and 12-16 in the context of all regulations BAAQMD is proposing or has recently enacted on the refineries. Without this comprehensive cumulative analysis, the full impact of these regulations is not being evaluated.

8.4 The DEIR failed to address cumulative impacts of measures taken to comply with proposed emission caps of Rule 12-16, toxic air contaminant risk reductions of Rule 1-18, and concurrently proposed regulations to limit refinery carbon intensity of combustion emissions Rule 13-1.

The DEIR concludes that while Rule 11-18 would reduce toxic air contaminant emissions, it could generate significant direct and indirect GHG emissions impacts and that Rule 12-16 would generate less than significant GHG emission impacts. The DEIR also states that GHG emission impacts are by definition a cumulative impact analysis. The DEIR considered the GHG impacts of implementing these rules alone and together, but did not consider the impacts together with concurrently proposed Rule 13-1, which aims to limit refinery carbon intensity relative to the facility's production of fuels. Since these rules would in some ways affect some of the same sources at the facilities (e.g. combustion sources, including both process devices and control devices), potential operational and control approaches would be determined by considering these rules together as the facilities might be subject to and have to comply with one or all of them. In addition, operational and control approaches will also affect the facility's net imports of power, steam, natural gas and/or hydrogen, which could likely result in an increase in indirect energy use and carbon intensity. For instance, installing pollution control devices, such as a wet gas scrubber or combustion device to reduce emissions of a criteria pollutant may result in an increase in direct or indirect GHG emissions or increases in other criteria pollutants; therefore there could potentially be an increase in emission intensity or carbon intensity of the production of transportation fuels with respect to those pollutants. What concurrent rules are in place will have a bearing on what emission control decisions and investments are made, so they must be evaluated together. With competing objectives and complex operating conditions to consider, operational flexibility is likely compromised.

Given all these constraints, facilities will have fewer feasible options to implement. The DEIR states that to comply with Rule 11-18 and Rule 12-16 facilities could reduce operations. As previously noted, the emission intensity per barrel of transportation fuel may increase if a facility must curtail production on some sources at the facility in order to meet the emission cap limits or risk reduction plan requirements. This would result in the refinery not operating as efficiently and thus may produce less transportation fuel per ton of pollutant. A refinery is optimized to be most efficient when its source units are operating near full capacity. This potential outcome should be considered along with the objectives of Rule 13-1 which seek to limit refinery carbon intensity, and thus would encourage operation at efficient optimized conditions. Therefore, the DEIR is deficient without a more complete cumulative analysis considering competing objectives of all the currently proposed rules.

8.5 The DEIR failed to address cumulative impacts of toxic air contaminants.

The DEIR failed to evaluate the impact of Regulation 11-18 and any residual health impacts that may be potentially significant even after implementation of this rule. This needs to be evaluated in the context of the current ambient levels of toxic air contaminants and existing regulations and policies that will change the environmental setting in the near future. It is unclear the extent that Regulation 11-18 will have on the cumulative amount of toxic air contaminants and associated health risks within the region.

8.6 The DEIR failed to fully evaluate the combined impacts of the two proposed regulations and any other related regulations being proposed by BAAQMD.

The BAAQMD has stated that these regulations are part of a larger strategy to address emissions in particular from refineries. This DEIR fails to evaluate Regulation 11-18 and 12-16 in the context of all of the proposed refinery regulations, as well as other regulations suggested in their draft air quality plan. By not evaluating the impacts of these regulations together as a single project and in a cumulative context, the DEIR fails to adequately capture potential significant impacts that could occur when the regulations are considered together. This is a classic example of splitting up projects to avoid disclosing an otherwise significant impact, which is not allowed under CEQA.

9 ALTERNATIVES ANALYSIS

9.1 The No Project Alternative is inadequate.

This section does not acknowledge that reduction in TAC emissions would result from controls adopted just to maintain risk below existing AB2588 notification and risk reduction thresholds, due to facilities reassessing health impacts using the updated OEHHA HRA methodology.

Several facilities with updated higher calculated risk would likely choose to or be required to adopt controls to remain below even the existing notification and risk reduction thresholds.

9.2 The basis for selecting Alternative 1.2 is not provided.

No basis is given for selecting a 25 in a million cancer risk and a Hazard index of 2.5 as appropriate thresholds. At a minimum this section could mention this level is consistent with that chosen by SCAQMD or perhaps based on similar rationale, though BAAQMD is choosing a HI threshold that is more stringent and less flexible than that chosen by SCAQMD. Some reference to the approaches taken in other regions of the state is relevant and should be included. The only justification provided is that this was requested in scoping comments.

9.3 Regulation 11-18 should be revised to match Alternative 1.2 which is designated as the superior environmental alternative.

If Alternative 1.2 is the environmentally superior alternative, why is it not the proposed project?

9.4 The evaluation of alternatives to Rule 12-16 are limited to only one proposal for establishing the caps.

BAAQMD does not provide support for the proposed 7 percent threshold allowance, nor does it consider whether an alternative to setting the caps at any other level might eliminate concerns of fuel shortage in the event of unanticipated long-term temporary loss of production or the ability to provide future adequate fuel supply to the local market. These important consequences and their potential environmental impacts should be evaluated and considered so that the possibility of unanticipated relocation (i.e., leakage) of emissions is minimized.

9.5 The Alternatives should have included a scenario where a facility or refinery is shut down.

These regulations have the real possibility of causing facilities and refineries in particular to cease operations in the region. The result of this leakage needs to be evaluated in the DEIR as an alternative. It is unclear if the impact of this would be a net benefit to the environment given socioeconomic impacts, additional transportation of goods and materials with increased air emissions and hazards to the area compared to the reduction in local air emissions that may occur. As mentioned earlier, transportation including goods movements is a dominant source of air quality emissions in far greater quantities than individual facility sources.

10 ACCURACY OF REFERENCES AND EDITORIAL MISTAKES

10.1 The introduction to Section 3 notes that the DEIR provides analysis for a list of environmental areas, not all of which are provided in the report.

Section 3.1 states that environmental analyses are provided in the DEIR for the following environmental areas:

- Air Quality;
- Climate change and greenhouse gas emissions;
- Hazards;
- Hydrology and water quality;
- Noise;
- Transportation and traffic; and
- Utilities and service systems

The Introduction further states that (1) Environmental Setting; (2) Regulatory Setting; (3) Significance Criteria; (4) Environmental Impacts; (5) Mitigation Measures (if necessary and available); and (6) Cumulative Impacts will be presented for each of those impact areas. Discussions related to noise and transportation/traffic impacts are not discussed in the DEIR. The Introduction should be revised for clarification, or these sections should be added to the DEIR. Note that the Initial Study concluded that the project would not cause potentially significant impacts related to noise or transportation/traffic. The Initial Study concluded that the project could have significant impacts on utilities (water supply and wastewater treatment). A brief section on Utilities and Service Systems is provided in the Executive Summary, but a separate section is not provided in the main text. A separate section should be included in the main text, or the Hydrology/Water Quality section should be revised to note that the discussions therein pertain to the potentially significant impacts associated with utilities as well.

10.2 Very few citations are provided for the data provided and when provided not all references listed are used and not all references used are referenced accurately or at all.

While this might just seem like an editing issue, it triggers the perception that this DEIR was developed in haste. The reviewer is not able to see on what this data is based that are presumably setting very stringent regional policy. Likewise a draft EIR (BAAQMD 2017) is cited several times over, which is considered in practice to be a questionable source.

10.3 There are numerous examples where available information was not obtained for the purpose of completeness.

There are numerous examples where available information was not obtained for the purpose of completeness. One such example, though not the only one, is in the Noise section which states that "It is not known if the existing commercial or industrial facilities affected by the rule are located within existing airport land use plans." This is available information and the BAAQMD has access to the locations of the affected facilities. There is no reason why answers to these questions could not be obtained and incorporated in order to complete and informed analysis to cite and substantiate the finding. If the detailed information is not available for potentially significant impacts, mitigation measures should be added to ensure that these impacts are evaluated on a project specific basis when complete information is available.

10.4 The General Information section does not provide General Plan Designations or Zoning as required.

These sections require information from the specific general plans. It appears that a cursory explanation and general reference that general plans typically exist was compiled, however no actual effort expended to research these Plans. This judgment is validated by the lack of referencing to such Plans in the document.

10.5 The introduction and Executive Summary provide subjective statements and concerns as context for the rule without reference to real trends and data.

The second paragraph of the introduction and executive summary alleges that refineries are 'significant' sources of global greenhouse gas, and regional/local criteria pollutants and toxics. A more specific reference to quantify their contribution (e.g., percentage of total) of specific pollutants to overall inventories could avoid misleading the reader. In addition, the possibility of an increase in refinery emissions due to changing operations might also be put in perspective as this would directionally not be expected given the many existing 'caps' on Potential to Emit and source emission limits in refinery permits, as well as continually tighter limits through New Source Review, numerous existing BAAQMD requirements, CARBs requirements, including the Cap and Trade program for GHG, and USEPA requirements.

10.6 Table 3.3-15 Title is inaccurate.

Table 3.3-15 includes electricity use for wet gas scrubbers and SCRs while the title only indicates that wet gas scrubbers are included.

10.7 The text citation of source of the 2015 GHG emission inventory does not match Table 3.3-3.

The text citation of source of the 2015 GHG emission inventory does not match Table 3.3-3. The DEIR should be corrected to use a consistent and accurate reference for the GHG emission inventory in 2015.

11 COMMENTS ON NOP/IS THAT WERE NOT ADDRESSED

This DEIR and staff reports have failed to address several previous comments on the regulation and the NOP/IS. CEQA requires that all comments are addressed prior to certification of the final environmental document.

11.1 The Areas of Potential Controversy provides an incomplete capture of potential areas of controversy received from scoping comments.

Some areas not included in this summary include (a) a request to include a dispute resolution process, (b) the concern with the adequacy of review given the span of possible facilities, (c) an understanding of how cumulative emissions might be factored when determining thresholds for enforcement, (d) how these regulations might discourage new renewal energy projects, and (e) how these regulations conflict with other legislation and specifically the District's Authority. Response to scoping comments is of course not required under CEQA, however by not doing so in some format it appears that each of these issues have not been addressed. It was noted that many of these facilities, specific to proposed Rule 11-18, are not aware of their status and have not had a reasonable opportunity to review these measures. The proposal as it stands does not include exceptions or dispute resolution to avoid more onerous, and in some cases more impactful, enforcement actions. The IS gave no specification on the facilities and the DEIR does not give consistent consideration of the types of facilities and resources that might be affected. Though it is assumed that the HRA process might consider cumulative emissions, without clarity on the process, the strength of the process and consistent application of the process is called to question.

11.2 The time period for Risk Reduction Plan is not enough time and does not allow for changes during detailed design.

A Risk Reduction Plan requires careful planning and detailed analysis of a variety of measures. With only 180 days, the Plan may result in insufficient characterization and planning with higher potential for unnecessary engineering. BAAQMD should extend the response time to 365 days to complete a thorough Risk Reduction Plan to ensure meaningful compliance. BAAQMD should add language to allow updating and modification of the risk reduction plans to provide a way to adjust a plan if there are problems during detailed design and implementation with a strategy outlined in the original plan.

11.3 Methods to demonstrate effectiveness of risk reductions measures needs to be clarified.

BAAQMD needs to clarify within the rule or within the Staff Report the methods that are acceptable for a facility to demonstrate effectiveness of risk reduction measures that are implemented.

11.4 Regulation 11-18 needs to be revised to include a process to reconcile potential disputes over risk reduction plan disapprovals

A dispute resolution mechanism is warranted given the unclear process to be used to make TBARCT determinations and the current lack of guidance available on what would be considered TBARCT for new and modified sources.

11.5 The release of draft documents is not appropriate for HRAs.

Facility information released to the public should be limited to only those facilities above risk action levels, and that only final, District-approved documents be released. Draft HRAs should not be released as only the final HRA that has been vetted by experts is appropriate for release to the public. HRA's are complex and require careful consideration by experts and they are not meant to be changeable or subjective based on public comments.

11.6 It is unclear how BAAQMD would determine appropriate time frames for implementation of risk reduction plans.

The Regulation 11-18 needs to clarify how BAAQMD would determine what is "technically feasible and economically practicable" and how or on what basis BAAQMD would determine the appropriate time period.

11.7 It is unclear under what conditions an updated risk reduction plan would be required.

Regulation 11-18 needs to clarify what new information it is anticipating in regards to health risks. What level of a health risk increase would prompt BAAQMD to act? Can BAAQMD force a facility to change its plan whenever a new control technology or risk reduction measure becomes available? BAAQMD should revise the language to clarify that the obligation to update the risk reduction plan is triggered only if new information (i) causes a facility to exceed the threshold for preparing such a plan for the first time, or (ii) increases the risk associated with the site by more than the significant risk threshold. Other triggers for updates should also be specifically addressed in the regulation such as when equipment no longer qualifies as TBARCT, addition or changes to TACs and toxicity factors, and changes to risk assessment models or methodologies. Would a new HRA be required every time the US EPA updates AERMOD?

12 MANADATORY FINDINGS OF SIGNIFICANCE IS INADEQUATE

12.1 The Mandatory Findings of Significance is inadequate and notably lacks substantial justification for impact findings; the findings under this section require reconsideration.

Based on many of these other resource-specific comments and notably the lack of substantial justification for impact findings, the findings under this section require reconsideration. The justification for there being no potential to degrade the quality of the environment is unsubstantiated and non-objective.

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SUPERIOR COURT OF THE STATE OF CALIFORNIA

FOR THE COUNTY OF CONTRA COSTA

VALERO REFINING COMPANY—CALIFORNIA, TESORO REFINING & MARKETING COMPANY, LLC, and PHILLIPS 66 COMPANY,

Petitioners/Plaintiffs,

v.

BAY AREA AIR QUALITY MANAGEMENT DISTRICT and DOES 1 through 20, inclusive,

Respondents/Defendants.

Case No. N16-0095

PETITIONERS' BRIEF IN SUPPORT OF PETITION FOR WRIT OF MANDATE

(Code Civ. Proc §§ 1085, 1094.5)

CEQA CASE

APPENDIX C

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I. INTRODUCTION

In 2014, the Board of Directors of the Bay Area Air Quality Management District (the "District") adopted a Resolution to better track and control refinery emissions, targeting a "20% reduction in refinery emissions, or as much emissions as are feasible . . . as expeditiously as possible." (Admin. Record Doc. ("AR Doc.") 150, at 002763-002764.) In response, District staff created the "Refinery Emission Reduction Strategy": a series of rules, issued in phases, collectively designed to achieve this goal within five years (the "Refinery Project"). (AR Doc. 117, at 002438.)

As the first component of the Refinery Project, the District put together a single package of new or revised rules, which it later segmented into three separate rulemaking packages. Petitioners now challenge the three rules adopted in the first rulemaking package, which represent the first step of the District's Refinery Project. These rules (the "Challenged Rules") are:

- Regulation 6, Rule 5: *Particulate Emissions from Refinery Fluidized Catalytic Cracking Units* ("Rule 6-5");
- Regulation 8, Rule 18: *Equipment Leaks* ("Rule 8-18"); and
- Regulation 11, Rule 10: *Hexavalent Chromium Emissions from All Cooling Towers and Total Hydrocarbon Emissions from Petroleum Refinery Cooling Towers* ("Rule 11-10").

(See AR Doc. 24 (Notice of Determination describing adoption of the Challenged Rules).)

The District's adoption of the Challenged Rules violates both the legislative intent and statutory requirements of the California Environmental Quality Act, Public Resources Code, § 21000 et seq. ("CEQA"). Agencies must consider and evaluate "the whole of an action" when they adopt new rules and cannot chop up actions into smaller components to minimize impacts or evade review. (Cal. Code Regs. tit. 14, § 15378(a).)[1] But the District did just that: it repeatedly and artificially limited its CEQA review to individual regulations, even while it continued to develop and discuss the Refinery Project as a whole. That piecemeal review subverts CEQA's core purpose of assuring a comprehensive assessment of "the whole of the action."

The District further violated California law when it adopted the Challenged Rules without

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[1] CEQA is implemented through the "Guidelines for Implementation of the California Environmental Quality Act," which are contained in California Code of Regulations, Title 14, Chapter 3, hereinafter referred to simply as the "CEQA Guidelines."

complying with requirements imposed by the California Health & Safety Code ("H&S Code"), including the District's obligation to make findings of necessity, consistency, and non-duplication under H&S Code § 40727, and to assess the cost-effectiveness of each rule under H&S Code § 40703. The record demonstrates that the District had determined to proceed with the Challenged Rules as a political matter before it even issued these rules for public comment. The District then proceeded to cherry-pick data to support its pre-ordained outcome while ignoring a wealth of data to the contrary. These arbitrary and capricious actions fail to demonstrate the necessity, consistency, and cost-effectiveness of the Challenged Rules and render them fatally flawed.

Petitioners are three refineries that will be significantly affected both by the Challenged Rules and by future Refinery Project rules that the District has identified as integral to achieving its objectives. Petitioners seek a writ of mandate from this Court ordering the District to (i) vacate the three Challenged Rules and (ii) comply with CEQA and the H&S Code in any future rulemaking to achieve the Board's Resolution.

II. REGULATORY HISTORY & STATEMENT OF FACTS

The Refinery Project originated in an October, 2012 "Work Plan," in which the District identified its desire to better track refinery emissions. (AR Doc. 122, at 002502.)[2] As the District began developing an emissions tracking rule, its focus expanded to include both tracking and reducing refinery emissions. (See AR Doc. 122, at 002502-002503; see also AR Doc. 124.) These efforts culminated with the District's adoption of Resolution 2014-07, unifying the District's efforts and expanding its goals. (See AR Doc. 150.)[3] Resolution 2014-07 directed District staff to continue efforts to track refinery emissions and to develop an integrated, broader strategy to reduce emissions from petroleum refineries by 20%, "or as much emissions reductions as are feasible." (AR Doc. 150, at 002763-002764.)

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[2] BAAQMD, Work Plan for Action Items Related to Accidental Releases from Industrial Facilities, at 2 (Oct. 11, 2012) (Action Item #4), at http://www.baaqmd.gov/~/media/Files/Technical%20Services/IncidentWorkPlan_Approved_10172012.ashx?la=en.

[3] At times, documents in the Administrative Record refer to Resolution 2014-07 as Resolution 2014-17. (See, e.g., AR Doc. 3, employing both terms.) Petitioners believe this is a typographical error. To avoid confusion, and for consistency, this brief will use the term Resolution 2014-07.

In response to this directive, District staff designed its comprehensive Refinery Project to achieve a 20% reduction in emissions of certain criteria pollutants[4] and a 20% reduction in health risks over a five-year period (2015-2020). (AR Doc. 117, at 002438; AR Doc. 46). The Project incorporated four main goals: (1) reducing criteria pollutants and precursors; (2) reducing health risks from air toxics; (3) tracking GHG emissions; and (4) improving control technology and practices. (AR Doc. 117, at 002438-002439.)

The District planned to implement its Refinery Project through a "suite" of coordinated rulemaking actions in 2015 and 2016. (*Id.*; see also AR Doc. 103, at 002278 (identifying Refinery Project phases and related rules).) As the first phase, the District planned to develop and adopt in 2015 a single package of rules to address criteria pollutants, focusing on sulfur dioxide ("SO_2") controls on refinery coke calciners, reductions in particulate matter ("PM") and PM precursors from Fluid Catalytic Cracking Units, and tightening requirements for equipment leaks. (AR Doc. 119, at 002469; AR Doc. 117, at 002438.) The District planned to follow this package with a second suite of rules to address the Refinery Project's second objective, reducing risk from air toxics. (AR Doc. 119, at 002469.) Two months after the Board passed Resolution 2014-07, it approved the District's "Strategy" to achieve the Resolution's goals. (AR Doc. 118, at 002448-002449.)

By January 2015, the District developed a suite of ten new or revised rules for study, development, and potential inclusion in the Refinery Project to complement the tracking and reduction rules already under development, which included Regulation 12, Rule 15: *Petroleum Refining Emissions Tracking* ("Rule 12-15") and Regulation 12, Rule 16: *Petroleum Refining Emissions Analysis, Thresholds, and Mitigation* ("Rule 12-16"). (AR Doc. 245, at 003770-003771.) The District targeted seven of those rules (including the three Challenged Rules) for adoption by late 2015 and indicated that these seven rules may collectively require an Environmental Impact Report ("EIR") under CEQA. (See AR Doc. 245-A, at 003770-003771, 003777-A.)

In May, the District decided to proceed with six rules instead of seven, and broke up this single suite of rules into three distinct rulemaking phases, as follows:

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[4] "Criteria pollutants" is a term of art under both the federal Clean Air Act and California regulations that refers to six common air pollutants.

- Phase 1: development of Regulation 9, Rule 14 ("Rule 9-14"), which the District asserted would "address emissions of SO_2 and the formation of PM";
- Phase 2: developing or amending the Challenged Rules, along with Rule 9-1, which the District asserted would further reduce SO_2 emissions and PM formation; and
- Phase 3: further amendments to Rules 6-5 and 9-1 and the addition of Rule 9-9 to address emissions from Stationary Gas Turbines at refineries.

(AR Doc. 46 at 001118-19.) These six rules were designed to "complement" and work in tandem with Rule 12-15 (the emissions tracking rule) and Rule 12-16 (which imposed emissions "caps" on refinery operations). (AR Doc. 46, at 001116.)

In October 2015, the District proposed a suite of six Refinery Project rules: Rule 9-14 (May's "Phase 1"); the three Challenged Rules (May's "Phase 2," without Rule 9-1); and Rules 12-15, and 12-16 (May's "Complementary" rules). (AR Doc. 9 (public hearing notice for Rules 6-5, 9-14, 8-18, 11-10); AR Doc. 53 (public hearing notice for Rules 12-15 and 12-16).) The District prepared a single EIR for Rules 12-15 and Rule 12-16, but did not prepare an EIR for the other rules. (AR Doc. 55.) The basis of the District's decision to prepare an EIR for only a portion of the Refinery Project—and, indeed, the District's entire treatment of this issue—is ever-changing, confused, and inconsistent. The District first characterized the remaining four rules (the Challenged Rules and Rule 9-14) as a separate individual "project," acknowledging that all four rules were "part of a concerted effort to reduce refinery emissions," and prepared a single draft Negative Declaration covering all four rules. (AR Doc. 12, at 000557; AR Doc. 13.) But this Negative Declaration evaluated each rule *separately* as an "individual action," based on the District's assertion that there were no "dependencies" between the four rules that comprised this new "project." (AR Doc. 12, at 000557; see also AR Doc. 9, at 000552; AR Doc. 12.)

On November 23 and November 30, 2014, Petitioners, both individually and as members of the Western States Petroleum Association ("WSPA"), provided several hundred pages of substantive and technical comments on the six proposed rules, identifying both technical inaccuracies and the common objective of each rule as interrelated components of the Refinery Project. (AR Docs. 32-36; AR Doc. 102, at 002270-74 (November 30, 2015 meeting minutes describing public comments on proposed Refinery Project Rules).)

By the December 16, 2015 public hearing on these rules, the District changed course yet again, chopping up these six rules into multiple Refinery Project rulemaking actions. At the public hearing, the District announced that it would consider adoption of only three of the six originally-proposed rules: Rules 6-5, 8-18, and 11-10 (*i.e.*, the Challenged Rules). (AR Doc. 3, at 000182-000183.) The remaining rules were delayed until 2016, although the District reiterated its intent to proceed with them, as they remained "important to meeting the Air District goals set forth in Resolution 2014-[0]7." (AR Doc. 3, at 000269.) Petitioners again provided oral comments at the December 16 public hearing. The District subsequently adopted the Challenged Rules and approved the accompanying Initial Study/Negative Declaration ("IS/ND"). (AR Doc. 8, at 000550; AR Doc. 5; AR Doc. 6; AR Doc. 7.) On January 22, 2016, Petitioners filed a Petition and Complaint alleging that the District violated CEQA, failed to comply with the H&S Code, and acted in an arbitrary and capricious manner when it adopted the Challenged Rules.

Less than two months after adopting the Challenged Rules, the District further segmented the Refinery Project by re-proposing Rules 9-14 and 12-15.[5] This time, instead of preparing an EIR for Rule 12-15, the District prepared individual Negative Declarations for both Rule 9-14[6] and 12-15.[7] The District adopted these two rules in April, 2016, and on May 25, 2016, Petitioners and WSPA filed a Complaint and Petition in this Court separately challenging the District's adoption of Rules 9-14 and 12-15, currently pending as Case No. N16-0963. The District stated that it continues to reassess Rule 12-16, and intends to develop still more rules under its Refinery Project. (AR Doc. 111, at 002376 (additional rules are "planned for 2016").)

III. STANDARD OF REVIEW

A. This Court Must Void Agency Decisions that Do Not Comply with CEQA.

CEQA requires all public agencies to conduct an environmental review of any "project" they

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[5] Rulemaking materials for Rules 12-15 and 9-14 are posted on the District's website, at http://www.baaqmd.gov/rules-and-compliance/rule-development/public-hearings.

[6] Negative Declaration for Rule 9-14, at http://www.baaqmd.gov/~/media/files/planning-and-research/public-hearings/2016/9-14-and-12-15/042016-hearing/0914-ceqa-042016-pdf.pdf?la=en.

[7] Negative Declaration for Rule 12-15, at http://www.baaqmd.gov/~/media/files/planning-and-research/public-hearings/2016/9-14-and-12-15/042016-hearing/1215-ceqa-042016-pdf.pdf?la=en.

carry out. (Pub. Res. Code § 21080.) A "project" is an "activity which may cause either a direct physical change in the environment, or a reasonably foreseeable indirect physical change in the environment." (Pub. Res. Code, § 21065.) CEQA "projects" include an agency's adoption of a rule or regulation, including those aimed at environmental protection. (*Cal. Unions for Reliable Energy v. Mojave Desert Air Quality Mgmt. Dist.* (2009) 178 Cal.App.4th 1225, 1240 (citing *Wildlife Alive v. Chickering* (1976) 18 Cal.3d 190, 206; *Plastic Pipe & Fittings Ass'n v. Cal. Bldg. Standards Com.* (2004) 124 Cal.App.4th 1390, 1412).)

When reviewing a project under CEQA, the lead agency must consider the "whole of an action." (Cal. Code Regs. tit. 14 § 15378(a).) CEQA forbids an agency from "chopping a large project into many little ones" to evade a full environmental review. (*Laurel Heights Improvement Ass'n v. Regents of Univ. of Cal.* (1988) 47 Cal.3d 376, 396 (quoting *Bozung v. LAFCO* (1975) 13 Cal.3d 263, 283-84).) A series of actions undertaken to attain the same objective comprises a single project. (*Tuolumne County Citizens for Responsible Growth, Inc. v. City of Sonora* (2007) 155 Cal.App.4th 1214, 1226-27) (hereinafter "*Tuolumne County*").)

The scope of a CEQA "project" is a question of law; courts afford no deference to an agency when determining what constitutes a project under CEQA. (*Tuolumne County,* 155 Cal.App.4th at 1224.) Upon finding that an agency has violated CEQA, a court may issue a writ of mandate voiding an action and requiring compliance with CEQA. (Cal. Pub. Res. Code § 21168.9(a).) "Directing an agency to void its approval of the project is a typical remedy [] for a CEQA violation." (*POET, LLC v. Cal. Air Res. Bd.* (2013) 218 Cal.App.4th 681, 759) (citation omitted).)

B. This Court Must Set Aside Rules That Fail to Comply With the H&S Code or Are Arbitrary, Capricious, or Lacking in Evidentiary Support.

The H&S Code imposes several substantive requirements on the District when it engages in rulemaking. Among other things, the District "*shall*" make findings and assure that rules meet the following criteria: "necessity, authority, clarity, consistency, nonduplication, and reference." (H&S Code § 40727 (italics added).) The District also "*shall* consider . . . the cost effectiveness of a control measure." (*Id.* § 40703.) These are mandatory requirements that the District must comply with when adopting any regulation. (*Id.* § 16 (H&S Code use of the word "shall" imposes a "mandatory" obligation).) The District must satisfy each of these requirements with "substantial evidence in the administrative record." (*Plastic Pipe and Fittings Ass'n,* 124 Cal.App.4th at 1406 (citations omitted).) Substantial evidence exists only when a "reasonable trier of fact could conclude that the evidence is reasonable, credible, and of solid value." (*Id.*, at 1407 (citation omitted).)

The District's decisions also must be fair and reasoned. If the District's actions are "arbitrary, capricious, entirely lacking in evidentiary support, unlawful, or procedurally unfair," this Court must set them aside. (*Am. Coatings Ass'n v. S. Coast Air Quality Dist.* (2012) 54 Cal.4th 446, 460.) The terms arbitrary and capricious are often bandied about but, in essence, these terms require an agency's decision to be soundly based on the facts before it. (See Black's Law Dict. (10th ed., 2014) ("arbitrary" means "a determination made without consideration of or regard for facts"; "capricious" means "contrary to the evidence").) When evaluating "whether a regulation is arbitrary, capricious, or lacking in evidentiary support, the court must ensure that an agency has 'adequately considered all relevant factors, and has demonstrated a rational connection between those factors, the choice made, and the purposes of the enabling statute.'" (*Am. Coatings Ass'n*, 54 Cal.4th 446, 460 (quoting *Golden Drugs Co., Inc. v. Maxwell–Jolly* (2009) 179 Cal.App.4th 1455, 1466).)

IV. ARGUMENT

A. The District Violated CEQA by Illegally Segmenting the Refinery Project and Failing to Review the Whole of the Action.

In late 2014, the District declared its intent to track and control refinery emissions, seeking a 20% reduction in refinery emissions and health risks to the extent that such reductions are "feasible." (AR Doc. 150, at 002763-002764.) To achieve these objectives, the District created the Refinery Project, an integrated set of regulatory actions taking place in several phases. (AR Doc. 117, at 002438-002439; AR Doc. 103, at 002278 (identifying Refinery Project phases and related rules).) No single phase or regulation is sufficient on its own to achieve the Refinery Project's overarching goal. As the District acknowledged, the Challenged Rules are each "part of a concerted effort to reduce refinery emissions." (AR Doc. 12, at 000557.)

Even though the District admitted that the Challenged Rules share the common objective "to reduce refinery emissions" (as required under the Board's directive) the District improperly segmented the Refinery Project into multiple CEQA analyses, evaluating each rule in isolation. This approach enabled the District to artificially minimize the total environmental impact of the Project as a whole, which in turn allowed the District to avoid preparing an EIR assessing *all* environmental impacts of the Refinery Project. These actions violate CEQA and frustrate its core purpose of informing the public and assuring a comprehensive review of "the whole of the action."

1. CEQA Requires Agencies to Analyze "The Whole of the Action" and Agencies May Not Evaluate Projects In a "Piecemeal" Manner.

It is black-letter law that an agency must evaluate "the whole of an action" under CEQA and cannot "chop up" projects into smaller components to avoid review. (Cal. Code Regs. tit. 14 § 15378(a); *Bozung*, 13 Cal.3d at 283-84.) Because the scope of review under CEQA must include the entire project, "a correct determination of the nature and scope of the project is a critical step in complying with the mandates of CEQA." (*Nelson v. Cnty. of Kern* (2010) 190 Cal.App.4th 252, 267 (citations and quotations omitted).) When a set of actions is aimed at a common objective—such as reducing refinery emissions by 20%—CEQA requires an agency to evaluate those actions *together*:

> One way to evaluate which acts are part of a project is to examine how closely related the acts are to the overall objective of the project. The relationship between the particular act and the remainder of the project is sufficiently close when the proposed physical act is among the "various steps which taken together obtain an objective.

(*Tuolumne County*, 155 Cal.App.4th at 1226-27 (quoting Robie *et al.*, Cal. Civil Prac. Envt'l Litig. (2005) § 8.7).)

Given CEQA's core "purpose of informing the public about potential environmental consequences, it is quite clear that an EIR is required even if the project's ultimate effect on the environment is far from certain." (*Cal. Bldg. Indus. Ass'n v. Bay Area Air Quality Mgmt. Dist.* (2015) 62 Cal.4th 369, 382.) This requirement is designed to assure that all of a project's impacts are considered at the same time, since a set of smaller actions often may result in a significant cumulative effect on the environment. (*Laurel Heights Improvement Ass'n*, 47 Cal.3d at 396.)

The fact that a specific project may occur through multiple components or phases does not excuse an agency from CEQA's mandate to evaluate "the whole of the action." (*Cal. Union for Reliable Energy*, 178 Cal.App.4th at 1242) (citing 1 Kostka Zischke, Prac. Under the Cal. Envt'l

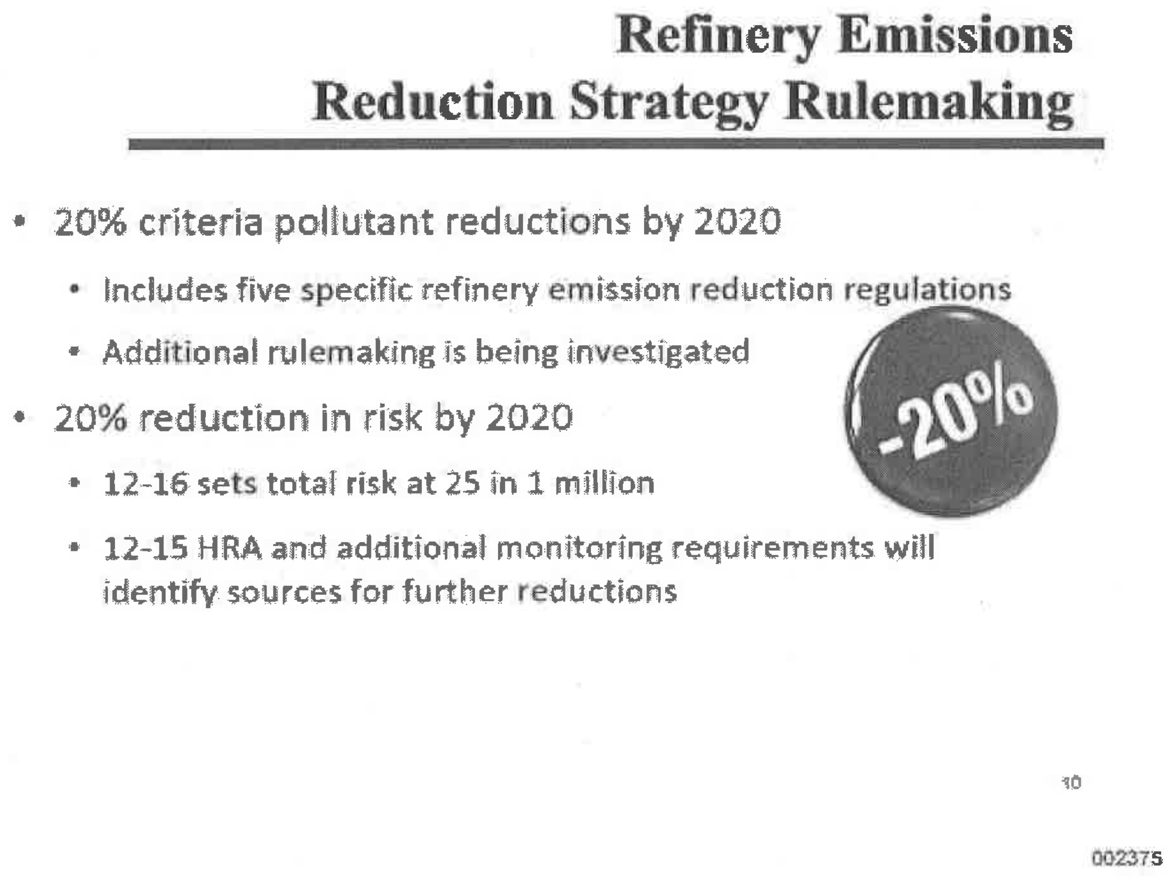
Quality Act, § 6.31, 329-330).) "This prevents agencies from chopping a large project into little ones, each with a minimal impact on the environment, to avoid full environmental disclosure. . . . Piecemeal environmental review that ignores the environmental impacts of the end result is not permitted." (*Id.*) Yet this type of "piecemeal environmental review" is exactly what the District has done here.

2. The District Improperly Segmented the Refinery Project to Evade CEQA Review.

The District did not prepare an EIR for the Refinery Project as a whole; nor did it even prepare an EIR for the three Challenged Rules. Instead, the District reviewed these three rules independently, concluded that each rule had no significant environmental impact, and adopted a single Negative Declaration. (AR Doc. 24.) The District claims that its Negative Declaration should not create an inference of interdependence between the Challenged Rules, and that its grouping of these three rules was performed solely "[f]or administrative convenience." (AR Doc. 12, at 000557.) But this Court, not the District, is the arbiter of a CEQA project's scope. (*Nelson*, 190 Cal.App.4th at 271). Its recent self-serving statements notwithstanding, the District's past actions and statements amply demonstrate that the Challenged Rules are not merely interrelated, they are part of a single Project.

From the moment the Board issued Resolution 2014-07, the District began to develop a unified approach and holistic plan to achieve the Resolution's goals. Within two months, the District had developed a multi-phased "Refinery Emission Reduction Strategy," which it intended to implement over the following two years. (AR Doc. 117, at 002438.) Within three months, the District held a "Refinery Emissions Reduction Strategy Kick Off Meeting" to discuss its "rule development efforts" and a unified approach to developing up to twenty individual rules under the Refinery Project—including the Challenged Rules and Rules 12-15, 12-16, and 9-14, among others. (AR Doc. 245, at 003768-74.) To manage this significant and coordinated undertaking, the District created a project workflow and organization chart assigning roles and responsibilities to twenty-two District staff members tasked with handling specific aspects of the District's Refinery Project rulemaking effort. (*Id.* at 003776.)

While the timing and details of the Refinery Project changed over the following months, this holistic approach—the District's plan to develop a number of interrelated rules, in multiple phases, to collectively achieve the objectives set forth by the Board's Resolution—did not. In March, the District reported that its staff had "developed a Refinery Emission Reduction Strategy in response to Resolution 2014-7, identifying specific rulemaking efforts to meet the goal of reducing refinery emissions by 20%," which included "a five-point action plan to provide a path forward to quickly and effectively address [refinery emissions]." (AR Doc. 112, at 002397). In June, the District presented that plan—again specifically linking each set of regulatory actions to the Project's objective of achieving a 20% reduction in refinery emissions and health risks. (AR Doc. 111, at 002376). The District's presentation explains this link quite clearly:



Refinery Emissions Reduction Strategy Rulemaking

- 20% criteria pollutant reductions by 2020
  - Includes five specific refinery emission reduction regulations
  - Additional rulemaking is being investigated
- 20% reduction in risk by 2020
  - 12-16 sets total risk at 25 in 1 million
  - 12-15 HRA and additional monitoring requirements will identify sources for further reductions

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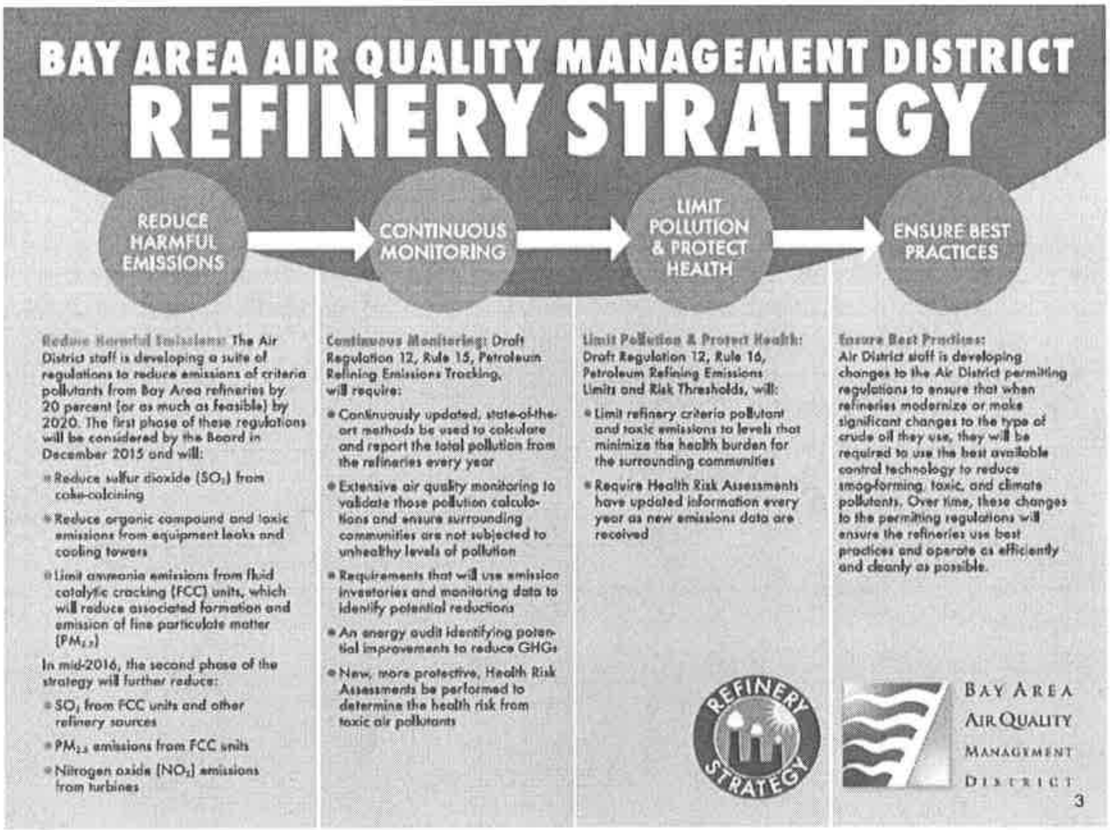
002375

(AR Doc. 111, at 002375).

The District continued to treat these rules as related parts of a single effort, both internally and in presentations to the public. Shortly before adopting the Challenged Rules, the District explained its Refinery Project using a straightforward chart:



BAY AREA AIR QUALITY MANAGEMENT DISTRICT

REFINERY STRATEGY

Reduce Harmful Emissions: The Air District staff is developing a suite of regulations to reduce emissions of criteria pollutants from Bay Area refineries by 20 percent (or as much as feasible) by 2020. The first phase of these regulations will be considered by the Board in December 2015 and will:

- Reduce sulfur dioxide (SO_2) from coke-calcining
- Reduce organic compound and toxic emissions from equipment leaks and cooling towers
- Limit ammonia emissions from fluid catalytic cracking (FCC) units, which will reduce associated formation and emission of fine particulate matter ($PM_{2.5}$)

In mid-2016, the second phase of the strategy will further reduce:

- SO_2 from FCC units and other refinery sources
- $PM_{2.5}$ emissions from FCC units
- Nitrogen oxide [NO_x] emissions from turbines

Continuous Monitoring: Draft Regulation 12, Rule 15, Petroleum Refining Emissions Tracking, will require:

- Continuously updated, state-of-the-art methods be used to calculate and report the total pollution from the refineries every year
- Extensive air quality monitoring to validate those pollution calculations and ensure surrounding communities are not subjected to unhealthy levels of pollution
- Requirements that will use emission inventories and monitoring data to identify potential reductions
- An energy audit identifying potential improvements to reduce GHGs
- New, more protective, Health Risk Assessments be performed to determine the health risk from toxic air pollutants

Limit Pollution & Protect Health: Draft Regulation 12, Rule 16, Petroleum Refining Emissions Limits and Risk Thresholds, will:

- Limit refinery criteria pollutant and toxic emissions to levels that minimize the health burden for the surrounding communities
- Require Health Risk Assessments have updated information every year as new emissions data are received

Ensure Best Practices: Air District staff is developing changes to the Air District permitting regulations to ensure that when refineries modernize or make significant changes to the type of crude oil they use, they will be required to use the best available control technology to reduce smog-forming, toxic, and climate pollutants. Over time, these changes to the permitting regulations will ensure the refineries use best practices and operate as efficiently and cleanly as possible.

REFINERY STRATEGY

BAY AREA AIR QUALITY MANAGEMENT DISTRICT

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(AR Doc. 103, at 002278.)

This chart bears a striking resemblance to the District's initial description of its "Strategy": multiple components, each relying on several regulatory steps that collectively build upon each other to achieve the District's objectives. In particular, the first component ("Reduce Harmful Emissions") consists of two phases: the Challenged Rules in 2015, followed by a second suite of rules in 2016. (*Id.*) The final component ("Ensure Best Practices"), in turn, will depend heavily on data collected through rules adopted under the second component ("Continuous Monitoring"). (*Id.;* see also AR Doc. 50 (District Staff Report explaining purpose of Rules 12-15 and 12-16).)

As the District's own documents demonstrate, the District's Refinery Project regulatory actions, including the Challenged Rules, are all aimed squarely at achieving its unified objective: track and reduce refinery emissions and health risks by 20%, or as much as feasible. (*Id.*) The District intended its suite of rules—the entire Refinery Project—to work together towards this common purpose. (*Id.*; see also AR Doc. 103, at 002280 (explaining that the Challenged Rules, plus Rule 9-14, may collectively amount to a 16% reduction in emissions, while additional regulations adopted in a "Phase

II rulemaking planned for 2016" may additively attain the 20% reduction goal).) The Board understood the interrelated nature of these efforts and adopted the Challenged Rules on that basis. (AR Doc. 8 at 000549 (noting that the Board had discussed "the Refinery Strategy and the proposed regulations the staff has presented, *including* the three regulations up for a vote today.") (italics added).) Given the interdependence of the District's regulatory actions and their common underlying purpose, it is plain that they are "various steps which taken together obtain an objective" and comprise a single "project" for purposes of CEQA. (*Tuolumne County*, 155 Cal.App.4th at 1226-27.)

While the District plainly understood the integrated nature of its Refinery Project rulemaking efforts, it took a cavalier and inconsistent view of its CEQA obligations throughout the rulemaking process. In early 2015, District staff recognized that "it would be good to consider the cumulative impacts of the whole suite of regulatory efforts" under CEQA. (AR Doc. 381, at 004850.) And when the District first outlined its initial Refinery Project rules, it recognized that its initial suite of rules may require an EIR. (AR Doc. 245-A, at 003770-003771, 003777-A (creating a "Task Schedule" for unified rule development and preparation of an EIR.) But by the time the District began to propose individual rules for adoption, its view of its CEQA obligations began to change. The District reformulated its approach on at least three different occasions:

- October, 2015: District proposes the Challenged Rules, 9-14, 12-15, and 12-16, concluding that (i) Rules 12-15 and 12-16 are a single "project" requiring an EIR and (ii) the remaining four rules are a separate individual CEQA "project." (AR Doc. 54; AR Doc. 12, at 000557.)
- December, 2015: the District severs the three Challenged Rules and adopts them with a single Negative Declaration prepared for "administrative convenience." (AR Doc. 24; see also AR Doc. 3, at 000357-000449.)
- January, 2016: District re-proposes Rules 9-14 and 12-15, ignoring its prior EIR for Rule 12-15 and grouping of Rule 9-14 with the Challenged Rules as a single "project," concluding instead that each of these two rules requires only a stand-alone Negative Declaration. (*Supra*, at 5, fn. 4-5.)

In short, the District appears to have redefined its CEQA obligations based on haste and expediency, resulting in an artificial compartmentalization of various Refinery Project rules and CEQA reviews structured for "administrative convenience." (AR Doc. 24, at 000675.) But CEQA requirements are driven by substance, not logistics. Because the Challenged Rules and numerous other rules (including but not limited to the subsequently-adopted Rules 9-14 and 12-15) were collectively designed to achieve a single purpose—the goals set forth in Resolution 2014-07—they are part of a single CEQA project. By analyzing the three Challenged Rules in isolation, the District addressed only a fraction of the entire Refinery Project. That action is not only misleading, it violates CEQA and subverts its purpose of assuring a comprehensive environmental review of "the whole of an action." (Cal. Code Regs. tit. 14 § 15378(a); *Bozung*, 13 Cal.3d at 283-84; *Nelson*, 190 Cal.App.4th at 271.)

3. The District Ignored Concerns Suggesting that an EIR Was Required to Fully Assess the Impacts of the Refinery Project.

District Staff is well aware that some of its Refinery Project rules are likely to cause significant environmental impacts, even when considered by themselves. In an early "Scoping Paper" for Rule 6-5, one of the Challenged Rules, District staff noted "Significant CEQA Issues" that include negative environmental impacts resulting from construction activities, GHG emissions, water use, and up to 30,000 gallons of wastewater per day resulting from each scrubber that the rule may require to reduce emissions. (AR Doc. 229, at 003402.) Because of these significant environmental impacts, District engineering staff cautioned in 2014 that "BAAQMD should expect to prepare an EIR for Reg 6-5 and should begin this process as early as possible in the process because of the likelihood of significant impacts." (AR Doc. 229, at 003403.) These concerns continued to appear in scoping paper drafts through early 2015. (AR Doc. 308, at 004138 ("One key issue that will almost certainly carry over from the South Coast experience is the need to perform an EIR.").) While the final, adopted version of Rule 6-5 differs from its draft form, the final Negative Declaration continued to note potential environmental impacts related to Rule 6-5. (AR Doc. 3, at 000383 (noting and evaluating "potential secondary adverse environmental impacts" stemming from compliance with Rule 6-5).)

Similarly, the District initially recognized that Rules 12-15 and 12-16 would require preparation of an EIR and even prepared a draft EIR for these two rules. (AR Doc. 55, at 001229.) As discussed above, however, the District subsequently severed Rule 12-15 from Rule 12-16, combined it instead with Rule 9-14, and declared that those two rules independently each required nothing beyond a Negative Declaration.

The District's actions highlight the problem CEQA seeks to avoid: by failing to consider Rule

6-5 and the other Challenged Rules alongside the rest of the Refinery Project, the District has artificially minimized the impacts of its actions and skirted CEQA's mandate to review *all* environmental impacts associated with a project, not just a few. (See *Laurel Heights Improvement Ass'n*, 47 Cal.3d at 396 (CEQA requires an agency to analyze all project components).)

This Court, not the District, is tasked with determining the scope of the District's Refinery Project. (*Tuolumne County*, 155 Cal.App.4th at 1224).) To further CEQA's dual purpose of informing the public and assuring review of "the whole of the action," this Court should issue a writ of mandate requiring the District to (i) vacate the NOD and Negative Declaration, (ii) vacate Rules 6-5, 11-10, and 8-18, and (iii) undertake a proper review under CEQA that considers "the whole of the action" when undertaking any future regulatory actions as part of the Refinery Project. (See Cal. Pub. Res. Code § 21168.9(a); *POET, LLC*, 218 Cal.App.4th at 759.)

B. The District Arbitrarily Ignored Information In the Record to Justify the Challenged Rules in Violation of H&S Code Requirements.

Before adopting new regulations, the District must evaluate several important H&S Code requirements: it must make findings that demonstrate the necessity, authority, clarity, consistency, non-duplication, and reference of the new or modified regulations, based on information in the rulemaking record. (H&S Code § 40727.) It also must make findings as to the cost-effectiveness of the regulations, including assessing the direct costs to be incurred by the regulated industry. (*Id.* § 40703.) The District's findings must be based on substantial evidence that is "reasonable, credible, and of solid value." (*Plastic Pipe and Fittings Ass'n*, 124 Cal.App.4th at 1407.) The District's evaluation also must "demonstrate[] a rational connection between those factors [and] the choice made." (*Am. Coatings Ass'n*, 54 Cal.4th 446, 460 (citation omitted).) An analysis failing this test is "arbitrary, capricious, or lacking in evidentiary support." (*Id.*)

In this case, the District failed to undertake the type of reasoned decision making required by the H&S Code and California law. As soon as the Board issued its resolution, District Staff developed a comprehensive plan to achieve a 20% emissions reduction as quickly as possible. The District's single-minded focus on achieving this goal, however, gave short shrift to these important H&S Code requirements: rather than viewing its statutory obligations as core analyses on which to build its rules, the District viewed them as little more than inconvenient hurdles for its Refinery Project to clear—as boxes to check on the path to its pre-determined result.

1. In adopting Rule 8-18 the District relied on outdated data, ignored existing federal requirements, and overestimated benefits.

Rule 8-18 requires refineries to perform periodic inspections for leaks from refinery equipment and to repair any leaks within a specific period of time. Most leak inspection programs reserve the most burdensome inspection and repair requirements (such as routine instrument monitoring) for equipment containing gases and light liquids; because heavy liquids do not have the same propensity to create airborne emissions, equipment containing these materials are inspected manually (*i.e.*, use of sight, smell, and sound to detect leaks). (See e.g., 40 C.F.R. § 60.482-8; *id.* § 60.482-8a (federal standards for heavy liquid service components providing for visual, audible, and olfactory detection methods).)

As part of the Refinery Project, however, the District amended Rule 8-18 to require refineries to extend the more burdensome inspection requirements to equipment containing heavy liquids. (See Dist. reg. 8, rules 8-18-113, 8-18-400; AR Doc. 3, at 000193-000203.) The District also narrowed the already-limited exemptions from the immediate repair obligations. (See Dist. reg. 8, rule 8-18-306; AR Doc. 3, at 000193-000203.) The District's stated purpose of these amendments is to achieve further reductions in fugitive emissions of organic gases and toxic compounds from certain refinery equipment. (AR Doc. 3, at 000241.)

The District's adoption of its Rule 8-18 amendments violated the H&S Code in three distinct ways. First, to demonstrate the necessity of Rule 8-18, the District relied exclusively on data from uncontrolled facilities during the 1970s and 1980s, while completely ignoring actual recent monitoring data from the very refineries regulated by the rule that demonstrate that emissions from heavy liquids are orders of magnitude lower. Second, based on these inflated emissions estimates, and ignoring significant compliance cost data, the District significantly overstated the emissions reductions the rule would achieve and understated the costs of compliance, leading to an inflated cost-effectiveness analysis. Third, the District failed to harmonize Rule 8-18 with existing federal regulations—regulations that *already require* monitoring of heavy liquid service equipment. Individually, any one of these flaws renders Rule 8-18 illegal, arbitrary, and capricious. Together, they highlight the District's "check-the-box" approach to rulemaking and its focus on predetermined outcomes, rather than on reasoned decision making and hard facts.

a. The District relied on incorrect and inflated emissions data to demonstrate the necessity of Rule 8-18.

The District justified the "necessity" of the revisions to Rule 8-18 based on its projection that leaks from equipment in heavy liquid service currently generate 1,476 tons per year ("tpy") of fugitive emissions. (AR Doc. 3, at 000243.) This estimate, however, is based on 40-year-old emissions factors that are indisputably outdated, and the District ignored substantial evidence in the record demonstrating that actual emissions from the refineries subject to Rule 8-18 are orders of magnitude lower. The District's exclusive reliance on outdated data and refusal to consider more reliable estimates epitomize arbitrary and capricious rulemaking.

The District developed its 1,476 tpy estimate by multiplying the total number of components in heavy liquid service by the emissions factors (emissions rate estimates) for each component type set forth in the U.S. Environmental Protection Agency's ("EPA") 1995 Protocol for Equipment Leak Emissions Estimates. (See AR Doc. 35, at 000953 (citing U.S. EPA, *Protocol for Equipment Leak Emissions Estimates*, EPA-453/R-95-017 (Nov. 1995), (hereinafter the "1995 Protocol").)[8] These emission factors were developed using data collected during the late 1970s from uncontrolled refineries. (1995 Protocol at 2-13 (Table 2-2, Footnote a, Reference 2), C-1 to C-2 (describing 1980 study); see also *id.* at 2-8 (describing that refinery average emission factors remain unchanged in the 1995 version of the Protocol).) Since these emissions factors were initially developed, however, fugitive emissions from refineries have been significantly reduced through multiple layers of leak detection programs. (See e.g., 40 C.F.R. § 60.482-8; *id.* § 60.482-8a.) These outdated emissions factors do not represent actual emissions from modern *controlled* facilities. (See AR Doc. 35, at 000953.)

Given the limitations of the emissions factors in the 1995 Protocol, California Air Resources

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[8] U.S. EPA, Protocol for Equipment Leak Emissions Estimates, EPA-453/R-95-017 (Nov. 1995), at https://www3.epa.gov/ttnchie1/efdocs/equiplks.pdf. 1995 Protocol emissions factors also are incorporated by reference in CARB's CAPCOA Guidance. (See *infra*, p. 18.)

Board ("CARB") guidance specifically limits their use: "[t]he Average Emission Factor Method [the method used by the District] may be used . . . to estimate overall emissions only when reliable site-specific screen data are not available." (See AR Doc. 3, at 000338; AR Doc 892, at 009628, 009636-37; AR Doc. 32 (citing CAPCOA/CARB, California Implementation Guidelines for Estimating Mass Emissions of Fugitive Hydrocarbon Leaks at Petroleum Facilities, (Feb. 1999) p. 7, at https://www.arb.ca.gov/fugitive/impl_doc.pdf (hereinafter "CAPCOA Guidance")).)

During rulemaking, Petitioners submitted reliable site-specific data—data *from the actual equipment subject to the rule.* The data demonstrates that actual fugitive emissions from equipment in heavy liquid service are far below the District's estimated 1,476 tpy. Specifically:

- Petitioner Phillips 66 provided the District with actual heavy liquid component monitoring data demonstrating that emissions from components in heavy liquid service are lower than the District's emissions estimates *by orders of magnitude.* (AR Doc. 33, at 000868; see also AR Docs. 160 & 161.)
- Petitioner Tesoro submitted actual monitoring data showing negligible emissions from components in heavy liquid service. (AR Doc. 35, at 000952-000954; AR Doc. 37, at 001020.)
- Petitioner Valero provided actual monitoring data confirming the low leak frequency of heavy liquid components. (AR Doc. 162, at 002826.)

The District refused to consider any of this data. The District did not actually identify any problems or errors in the data; rather, it summarily dismissed the data as "inadequate" solely because it "was not collected in such a way that the Air District could verify that it accurately represented the emissions from components in heavy liquid service"—even though all of the data was collected using EPA-approved sampling methodologies and test methods. (AR Doc. 3, at 000244; see also, e.g., AR Doc. 33, at 000868, 000874 (Phillips 66 Company providing EPA-approved Method 21 monitoring results to District staff).)

The District's findings must be based on substantial evidence that is "reasonable, credible, and of solid value" (*Plastic Pipe and Fittings Ass'n*, 124 Cal.App.4th at 1407), and that bears a "rational connection" to the District's ultimate determination (*Am. Coatings Ass'n*, 54 Cal.4th 446, 460). By arbitrarily choosing to rely on 40-year-old emissions factors that even CARB and EPA suggest are unreliable—especially when provided with recent, actual data from the very sources at issue—the

District has failed to satisfy even this most basic rulemaking requirement.

Even the District admits that it needs more data to evaluate the utility of Rule 8-18, and since 2014 the refineries have repeatedly offered to collect data and study emissions from heavy liquid components. When it adopted Rule 8-18, the District noted that it has finally accepted this offer (AR Doc. 3, at 000244) and that once the study is completed, the District will "determine if the proposed regulatory requirements for equipment in heavy liquid service continue to be cost effective." (AR Doc. 3, at 000279.) The District has it backwards: it must demonstrate the necessity of a regulation *before* choosing to regulate—not after the fact.

This "regulate first, ask questions later" approach entirely subverts the "necessity" requirement and epitomizes arbitrary and capricious rulemaking. The H&S Code requires the District to show that "a need exists for the regulation . . . *as demonstrated by the record of the rulemaking authority.*" (H&S Code § 40727(b)(1).) Petitioners submitted extensive, real-world monitoring data from the very refineries that will be subject to the rule. (AR Doc. 33, at 000868; AR Doc. 35, at 000952-000954; AR Doc. 37, at 001020; AR Doc. 162, at 002826.) These data points—from not just one refinery, but from three separate refineries—demonstrate that the emissions from heavy liquid components are orders of magnitude lower than the District's assumptions. (*Id.*) And yet the District flatly ignored all of this real-world data, instead choosing to proceed based solely on 40-year-old data from unrelated, uncontrolled facilities—data that even CARB agrees is so unreliable that it should not be used when site-specific data is available. The District has failed to meet its burden of demonstrating that its revisions to Rule 8-18 are "necessary" based on information that is "reasonable, credible, and of solid value." (*Plastic Pipe and Fittings Ass'n*, 124 Cal.App.4th at 1407.)

b. The cost-effectiveness analysis for Rule 8-18 is fatally flawed because it relies on inflated emissions estimates and understated costs.

The District's inflated baseline emissions estimate invalidates its cost-effectiveness analysis as well. The District's projected emissions reductions (1,227 tpy) derives directly from its assumption that current actual emissions are 1,476 tpy. But these "projections" significantly overstate the true emissions reductions that the rule might achieve: actual emissions data submitted by Petitioners indicate that current emissions *are already an order of magnitude or more below* the assumed 1,227 tpy future reduction. (AR Doc. 33, at 000868; AR Doc. 35, at 000952-000954; AR Doc. 37, at 001020; AR Doc. 162, at 002826.)

The District's gross overstatement of Rule 8-18's benefits is compounded by its understatement of the Rule's compliance costs. Refineries have hundreds of thousands of heavy liquid components in service. Petitioners estimated the capital costs and staffing costs of tagging and inspecting each individual component will run well into the millions of dollars. (AR Doc. 33, at 000869; AR Doc. 35, at 000954). The District simply ignored these costs.

Longstanding District guidance indicates that its cost-effectiveness threshold for an emissions reduction rule targeting the kinds of pollutants regulated by Rule 8-18 is $17,500 per ton. (AR Doc. 189, at 002977) (BAAQMD, Best Available Control Technology and Best Available Technology Workbook, Sec.1, Policy and Implementation Procedure, (2002) p. 5); see also AR Doc. 189, at 002969-70 (district staff discussing cost effectiveness thresholds).) The District's cost-effectiveness evaluation for Rule 8-18 assumed 1,227 tpy of emissions reductions at a cost of $6.8 million per year, or $5,542 per ton. (AR Doc. 3, at 000228.) Using the data the refineries supplied for both current emissions and compliance costs, Petitioner Phillips 66 calculated an actual cost of $231,000 per ton—far beyond the District's $17,500 threshold. (AR Doc. 33, at 000869.)

The District's cost-effectiveness analysis also failed to consider the costs (both economic and environmental) associated with lowering the mass emissions limit for leaking equipment placed on a facility's non-repairable list (often called a "delay of repair" or "DOR" list). All leak detection and repair programs, including Rule 8-18, allow repairs to be delayed if the leak cannot be repaired without shutting down a process unit.[9] (See Dist. reg. 8, rules 8-18-226, 8-18-306.) This exemption, however, is narrow: only equipment that cannot be repaired without a process unit shutdown is eligible to be placed on the DOR list and the total mass emissions from components placed on the DOR list is limited. The District's recent revisions to Rule 8-18 significantly reduce this mass emissions limit.

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[9] Forcing a refinery to shut down immediately if a leak cannot be repaired typically requires high volumes of process gases to be sent to the flare for combustion, which generates far more emissions than a leaking valve or flange. Accordingly, when a particular leak cannot be repaired or removed from service without a process unit shutdown, both EPA and the District have long allowed refineries to delay the required repair until the next planned process unit shutdown. (See, e.g., 40 C.F.R. § 60.482-9; *id.* § 60.482-9a; AR Doc. 3, at 000193-000203 (showing District's changes to Rule 8-18).)

(AR Doc. 3, at 000193-000203 (showing District's changes to Rule 8-18).) But in deciding to reduce this limit, the District has failed to consider the potential consequences. Equipment cannot be placed on the DOR list unless the only other alternative is an immediate process unit shutdown. And if the equipment already on the DOR list reaches the mass emissions limit, no more equipment may be placed on that list—meaning that the next unrepairable leak will require an immediate process unit shutdown in order to remain in compliance with Rule 8-18 The District failed to consider the likelihood that significantly reducing the total allowed emissions from components on the DOR list may in fact force unplanned refinery shutdowns—with their very significant additional emissions and costs—in order to comply with these new requirements. Nor did the District consider the quantity and environmental impact of these excess emissions or the scope of the economic costs associated with such an event. (AR Doc. 35, at 000956; AR Doc. 32, at 000734-000735.)

c. The District ignored the impact of existing regulations on fugitive emissions and failed to harmonize Rule 8-18 with federal requirements.

The District also failed to make the required findings of consistency and non-duplication for Rule 8-18. (H&S Code § 40727(4)-(5).) Refineries are subject to a panoply of federal and state regulation, including federal standards for equipment in heavy liquid service. (See 40 C.F.R. § 60.482-8.) The District was required to demonstrate that its revisions to Rule 8-18 are consistent with and do not duplicate these existing requirements to the extent possible. (H&S Code § 40727.) But the District violated this requirement by assuming away the impact of the federal requirements, merely because they "do not rely on instrument measurements." (AR Doc. 3, at 000241.)

As discussed above, the District's analyses and emissions estimates assume that equipment in heavy liquid service is unregulated. Yet the District is well aware that the refineries are in fact subject to federal rules that impose specific and detailed requirements for monitoring and repairing leaks using visual, audible, olfactory, and other detection methods. (See *id.*) The District justifies this omission by arbitrarily *assuming* that the federal standards are insufficient—*i.e.*, that instrument monitoring is the only effective way to detect leaks from heavy equipment. *There is no evidence in the record* to support the District's incorrect assumption.[10]

The District also failed to consider the significant costs and difficulties the refineries would incur in attempting to comply with these two overlapping and inconsistent programs. The District's revisions to Rule 8-18 fundamentally require refineries to develop a dual monitoring program for heavy liquids: facilities would still be subject to the visual, audible, and olfactory inspections under federal rules, but also would be required to conduct instrument monitoring on those same components under Rule 8-18. Nowhere has the District evaluated the costs of operating two parallel programs, or assessed whether alternatives exist that would minimize the inconsistencies and overlap between these conflicting standards, as required by the H&S Code.

2. Rule 11-10 is not necessary, fails to consider compliance costs, creates duplicative regulation, and is based on emissions data arbitrarily selected by the District to achieve a pre-determined end.

Rule 11-10 was first developed in the 1980s to reduce hexavalent chromium emissions from cooling towers. The amendments to Rule 11-10 adopted by the District add stringent new leak monitoring and repair requirements, which the District concluded are necessary based on a single heat exchanger leak that occurred in 2010.[11] (AR Doc. 3, at 000251.) Once again, the District's analysis violates the H&S Code in three ways: (i) it bases its necessity determination on cherry-picked data while ignoring actual monitoring data, (ii) it overstates the benefits and understates the costs of the new rule; and (iii) it ignores the significant cooling tower monitoring and repair requirements now required under comparable federal rules. (See 40 C.F.R. Part 63, Subpart CC.)

a. Rule 11-10 is not necessary because real-world emissions are already at or below the emissions levels sought by the District.

The District determined that Rule 11-10 is necessary to reduce emissions of total hydrocarbons based on its calculation that current cooling tower emissions are 978 tpy, using refinery emissions

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[10] As noted above, heavy liquids are less likely to create airborne emissions and are easier to detect—dripping liquids and stains on the ground are much more obvious to the naked eye than invisible gases volatilizing from a leaking valve. (See *supra* § IV.B.1; see also 40 C.F.R. § 60.482-8 (federal leak detection requirements).)

[11] This 2010 event occurred before federal monitoring and repair requirements became effective for cooling towers, but federal regulations now govern the same refinery components reached by Rule 11-10. (See 78 Fed. Reg. 37133 (June 20, 2013) (noting effective date of revised federal regulations of June 20, 2013.)

factors from EPA's "AP-42, Compilation of Air Pollutant Emission Factors" ("AP-42"). (AR Doc. 3, at 000255; see also AR Doc. 42, at 1084 (citing U.S. EPA, Compilation of Air Pollution Emission Factors, Table 5.1-2 (5th ed., 1995), at https://www3.epa.gov/ttn/chief/ap42/c00s00.pdf (hereinafter "AP-42").) AP-42 emissions factors are a generalized method of calculating emissions and used only as a "last resort"—EPA specifically notes that "[d]ata from source-specific emissions tests or continuous emissions monitors are usually preferred for estimating a source's emissions because those data provide the best representation of the tested source's emissions." (AP-42, Introduction, p. 3.) Only when "representative source-specific data cannot be obtained" and "emissions information from equipment vendors . . . or actual test data" also is not available, then "*use of emissions factors may be necessary as a last resort.*" (*Id.*, at 3 (italics added).).[12]

In addition to these general concerns with the accuracy of AP-42 emissions factors, some emissions factors are more reliable than others. EPA has rated each emissions factor from A to E, with "A" being the most reliable. (*Id.* at 8.) The emission factor for petroleum refinery cooling towers is rated a "D"—*i.e.*, below average, signifying that the emission factor was developed from "a small number of facilities, and there may be reason to suspect that these facilities do not represent a random sample of the industry." (*Id.*, Introduction, at 10; Chapter 5, Table 5.1-3, at 5-1.16).

The District also used the wrong emissions factor. AP-42 lists separate emissions factors for "controlled" and "uncontrolled" cooling towers. (*Id.* Chapter 5, Table 5.1-3, at 5-1.16.) The District's calculation is based on the EPA emission factor for *uncontrolled* cooling towers. (AR Doc. 3, at 000255 (italics added).) However, the majority of the refinery cooling towers in the Bay Area are *controlled* facilities, because they are subject to existing EPA federal rules. (AR Doc. 32, at 00076) (explaining that 24 of 32 cooling towers are already subject to federal requirements).)[13] By assuming away the existence of these federal requirements, the District further overstated the current emissions from Bay Area cooling towers.

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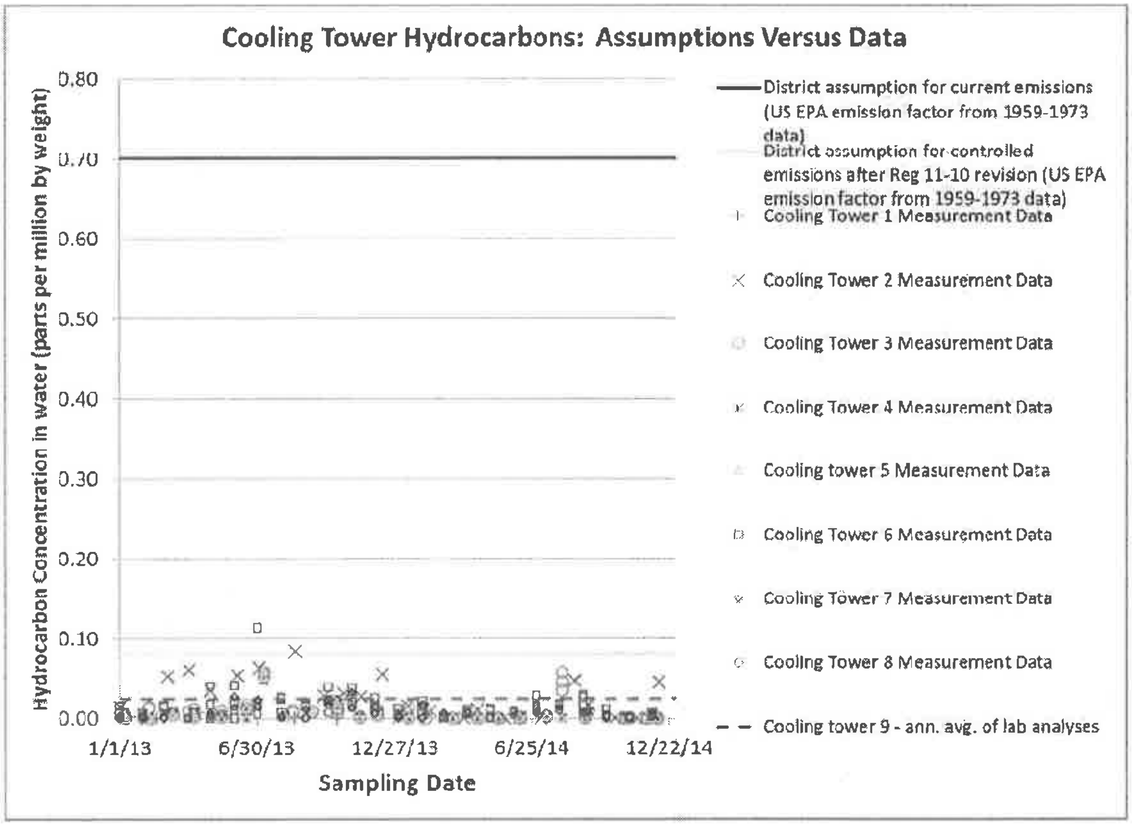
[12] CARB guidance is consistent with this approach. (See generally CAPCOA Guidance).

[13] The AP-42 document considers "controlled" cooling towers to be those in which cooling water contamination is reduced "through the proper maintenance of heat exchangers and condensers." (AP-42, Chapter 5, § 5.1.3.5 at 5.1-18.) These are the same types of requirements imposed under Subpart CC. (See, e.g., 40 C.F.R. § 63.654 (heat exchange systems).)

Given these many concerns with the District's emissions estimates, Petitioners and WSPA submitted real-world data—actual monitoring data from the very cooling towers regulated under Rule 11-10—demonstrating that current emissions were orders of magnitude below the District's assumptions. For example, Petitioner Phillips 66 submitted actual monitoring data showing that average emissions from the refinery's cooling towers were *already* at or below the level of total hydrocarbons that the District sought to attain under the new provisions of Rule 11-10. (AR Doc. 33, at 00870.) In addition, WSPA submitted the following chart comparing the District's emissions assumptions with actual measurements from Bay Area refineries:



(AR Doc. 32, at 000761.)

The District refused to consider any of these data. Instead, the District cited unspecified "concerns" with the method by which the data were collected (the "modified El Paso method" or "MEPM")—a test method specifically approved by EPA. (AR Doc. 3, at 000254.) Petitioners submitted comments explaining why MEPM is the most accurate method of measuring cooling tower emissions. (AR Doc. 34, at 000934; AR Doc. 35, at 000959). Again, the District refused even to consider this data based on its as-yet unpublicized "concerns"—and after excluding data that AP-42 itself ranks as more reliable than AP-42 emissions factors—the District then based its evaluation of the necessity of the rule solely on the AP-42 emissions factors. (AR Doc. 3, at 000254.) The District's conclusion that relying on "last-resort" emissions factors is more "reasonable, credible, and of [more] solid value" than recent test data obtained using the federally-approved test method defies belief and represents an entirely arbitrary and capricious choice. (*Plastic Pipe and Fittings Ass'n*, 124 Cal.App.4th at 1407.)

b. Rule 11-10 employs inflated emissions estimates to justify regulatory requirements that would not otherwise be cost-effective.

The District estimated that current VOC emissions from cooling towers are 978 tpy, based on AP-42 emissions factors for uncontrolled facilities. (AR Doc. 3, at 000256.) The District then estimated Rule 11-10 would reduce this figure by 88% (861 tpy reduction), which it then used to support its conclusion that the rule was cost-effective. (AR Doc. 3, at 000256-000258.) As with the heavy liquids data, the District's artificially elevated calculation of "current" emissions leads to an artificially elevated projection of future emissions reductions.

The District compounds this error by ignoring the emissions reductions already achieved under applicable federal regulations. As discussed above, the District based its emissions estimates on the assumption that all cooling towers in the District are "uncontrolled" (as that term is used in AP-42). (AR Doc. 3, at 000255.) However, as also discussed above, many of these cooling towers are in fact already controlled under 40 C.F.R. Part 63, Subpart CC. As a result, the District credits Rule 11-10 with emissions reductions that *have already been achieved* by the pre-existing federal rules. Again, this erroneous attribution allows the District to conclude that the amendments to Rule 11-10 are cost-effective.

The District cannot rely on emissions reductions already achieved by federal rules to justify its own overlapping rules. To properly calculate the *actual* benefits of Rule 11-10, the District would need to calculate (i) the emissions reductions associated with applying cooling tower monitoring to those cooling towers not already covered by federal regulations; and (ii) any incremental emissions reductions achieved by requiring cooling towers already regulated under Subpart CC to perform more frequent monitoring under Rule 11-10. By failing to undertake that basic analysis, the District has failed to demonstrate the cost effectiveness of Rule 11-10.

c. Rule 11-10 is duplicative of federal regulations requiring monitoring of heat exchangers and inconsistent with those requirements.

Many of the refinery cooling towers in the Bay Area are already required, pursuant to EPA regulations, to implement a cooling tower monitoring program and to correct any leaks detected. (See 40 C.F.R. § 63.654.) Rule 11-10 requires these same cooling towers to implement a second monitoring program on top of existing federal requirements. The District is well aware of the overlap, with staff noting early in the rulemaking process that they were "still a bit surprised by the cooling tower emissions" rule given that federal requirements under 40 C.F.R. section 63.654 were "already applicable" to refinery cooling towers and heat exchangers. (AR Doc. 228, at 003398.) Despite this awareness, the District never appropriately evaluated the consistency of these programs or assessed whether the programs would require unnecessarily duplicative compliance efforts.

The District prepared a cursory chart comparing applicable requirements under Subpart CC and Rule 11-10. (AR Doc. 3, at 000261-000263.) However, the District did not evaluate the significant differences in these programs, nor did the District analyze the extent to which the specific requirements of Rule 11-10 conflict with the refineries' obligations under Subpart CC. For example, Subpart CC requires refineries to conduct monthly monitoring to detect heat exchanger leaks; EPA has approved the use of the MEPM sampling methodology for these purposes. (See U.S. EPA, "Emissions Estimation Protocol for Petroleum Refineries", Version 3, Apr. 2015, at 8-2.) Rule 11-10, in turn, requires these same refineries to implement a daily monitoring program at these same cooling towers. However, the District does not allow the use of MEPM as approved by EPA; rather, the refineries may use MEPM only if they make changes to the sampling methodology. (AR Doc. 3, at 000253; AR Doc. 3, at 000519.) Yet EPA has never approved the District's changes for compliance with the federal rules. As a result, refineries will be forced to conduct two parallel monitoring programs—one following the federal requirements, one following the District's requirements—for the same equipment, to achieve the same outcome. The District simply ignored the problem presented by these inconsistent and duplicative requirements, violating the H&S Code's mandate to assess the consistency and nonduplication and avoid conflicting obligations.[14] (H&S Code § 40727.)

3. Rule 6-5 is based on guesswork and assumptions that contradict the District's own prior analysis.

Rule 6-5 establishes new, stringent ammonia emissions limits on refinery fluidized catalytic cracking units ("FCCUs") because it asserts that ammonia is a significant "precursor" to the formation of fine particulate matter ("$PM_{2.5}$") in the atmosphere[15] (*i.e.*, ammonia, together with other materials in the atmosphere, contributes to the formation of $PM_{2.5}$).[16] (AR Doc. 3, at 000234.) Because the District asserts that ammonia emissions may lead to the formation of $PM_{2.5}$ in the atmosphere, the District maintains that these first-ever ammonia limits are "necessary to ensure the attainment and maintenance" of the National Ambient Air Quality Standards ("NAAQS") and California Ambient Air Quality Standards ("CAAQS") for $PM_{2.5}$. (AR Doc. 3, at 000232.)

The District's current assertion directly contradicts the claims it made two years ago, when it persuaded EPA that ammonia emissions do *not* contribute significantly to $PM_{2.5}$ levels in the Bay Area. Under the Clean Air Act, the District must ensure that its New Source Review program applies not just to $PM_{2.5}$ itself, but also to any precursors that contribute significantly to the exceedance of the NAAQS for $PM_{2.5}$. (See 40 C.F.R. § 51.166(b)(49) (describing regulated NSR pollutants as including precursors.) Two years ago, the District revised its New Source Review program to *exclude* ammonia as a $PM_{2.5}$ precursor because, as the District concluded at the time, *ammonia is "not a significant contributor to secondary PM formation*." (AR Doc. 32, at 000730-31 (citing Letter from J. Karas,

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[14] The District also failed to consider simple solutions to this problem, such as extending the federal Subpart CC requirements to currently-exempt cooling towers rather than implement an entirely new and unnecessary regulatory program. (See AR Doc. 32, at 000738.)

[15] Direct emissions of particulate matter are typically referred to as "primary" particulate matter. Particulate matter that forms in the atmosphere from other gaseous pollutants, such as ammonia, is referred to as "condensable" or "secondary" particulate matter. (See U.S. EPA, Report on the Environment, Particulate Matter Emissions, at https://cfpub.epa.gov/roe/indicator.cfm?i=19.)

[16] The District does not claim the authority to regulate ammonia directly, citing only its general authority to regulate criteria pollutants such as $PM_{2.5}$. (H&S Code 63.654(a), (c); AR Doc. 3, at 000232.) Instead, the District has imposed these new emissions limits because it asserts that ammonia is a significant "precursor" to the formation of fine particulate matter ("$PM_{2.5}$") in the atmosphere (*i.e.*, ammonia, together with other materials in the atmosphere, contributes to the formation of $PM_{2.5}$). (AR Doc. 3, at 000234.)

BAAQMD, to G. Rios, EPA Region 9 (Dec. 22, 2015)).) If, as the District concluded two years ago, ammonia is "not a significant contributor to secondary PM formation," then controlling ammonia emissions cannot be "necessary" to ensure the attainment and maintenance of the $PM_{2.5}$ NAAQS and CAAQS.

To put it another way, two years ago, the District concluded that 686 tpy of ammonia emissions from three industries did not significantly contribute to secondary PM formation. (See AR Doc. 32, at 000730-31 (citing Letter from J. Karas, BAAQMD, to G. Rios, EPA Region 9 (July 15, 2015).) The District's estimates suggest that the refineries regulated by Rule 6-5 collectively emit 444 tpy of *total* condensable $PM_{2.5}$ emissions from FCCUs (*i.e.*, ammonia and all other precursors *combined*). (AR Doc. 3, at 000236). Yet there is no evidence in the record explaining why the District has now concluded that less than 444 tpy of ammonia emissions significantly impacts $PM_{2.5}$ formation, when just two years ago the District concluded that 150% of that amount did not.

Nowhere does the District provide any reasoned basis for this about-face. The District has performed no new evaluations, nor has it identified new scientific or technical data to support its change of heart. Indeed, if anything, the record demonstrates that the District was fully aware that the link between ammonia emissions and $PM_{2.5}$ formation is highly tenuous at best. As early as the District's May 2015 Initial Report, the District noted that while "[t]here is reason to believe that this [the reduction of ammonia emissions under Rule-6-5] would also reduce emissions of condensable PM . . . *it is not possible to quantify that at this time*." (AR Doc. 46, at 001123 (italics added).) The final December 2015 Staff Report came no closer to defining the estimated emissions reductions based on supporting data: the District characterized the factual basis for its figures as "based on a very small number of *non-standard* tests on FCCUs" and identified both its emissions calculations and the impact of the new ammonia controls on PM formation as "uncertain." (AR Doc. 3, at 000228 (italics added).)

In other words, the District *assumes* that the ammonia emissions limits will reduce the formation of $PM_{2.5}$ formation, but admits that it does not know if that is actually true, or to what extent. To remedy this knowledge gap, the District indicated that it is "currently working with refineries that operate FCCUs to perform source testing of condensable $PM_{2.5}$ emissions using the most recently developed and accurate testing methods." (AR Doc. 3, at 000234, 000274).

Again, the District's approach is backwards: it must establish the necessity for a particular rule before promulgating it—not regulate in the hope that emissions will decrease and that subsequent testing will justify its decision. The District has failed to demonstrate the necessity of Rule 6-5, in violation of H&S Code § 40727.

V. CONCLUSION

For all of the foregoing reasons, this Court should grant the Petition and issue a writ of mandate requiring the District to vacate the Challenged Rules and comply with the requirements of CEQA and the H&S Code in this and any other rulemaking action related to the Refinery Project.

Dated: August 31, 2016

Respectfully submitted,

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PROOF OF SERVICE

I, the undersigned, declare that I am employed in the County of San Francisco; I am over the age of eighteen years and not a party to the within entitled action; my business address is Beveridge & Diamond, P.C., 456 Montgomery Street, Suite 1800, San Francisco, CA 94104-1251.

On August 31, 2016, I served the following document(s): **PETITIONERS' BRIEF IN SUPPORT OF PETITION FOR WRIT OF MANDATE** on the interested party(ies) in this action.

Adan Schwartz
Senior Assistant Counsel
Bay Area Air Quality Management District
939 Ellis Street
San Francisco, CA 94109
E-mail: aschwartz@baaqmd.gov

The documents were served by the following means:

☒ BY ELECTRONIC TRANSMISSION: Based on an agreement of the parties to accept service by electronic transmission, I caused the documents to be sent to the person at the electronic notification address set forth above.

I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct.

DATED: August 31, 2016 BY: Rob Onaka
ROBIN ONAKA

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SUPERIOR COURT OF THE STATE OF CALIFORNIA

FOR THE COUNTY OF CONTRA COSTA

WESTERN STATES PETROLEUM ASSOCIATION; VALERO REFINING COMPANY—CALIFORNIA; TESORO REFINING & MARKETING COMPANY, LLC; and PHILLIPS 66 COMPANY,

Petitioners/Plaintiffs,

v.

BAY AREA AIR QUALITY MANAGEMENT DISTRICT and DOES 1 through 20, inclusive,

Respondents/Defendants.

Case No. N16-0963

PETITIONERS' REPLY BRIEF IN SUPPORT OF PETITION FOR WRIT OF MANDATE

(Code Civ. Proc §§ 1085, 1094.5)

CEQA CASE

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I. INTRODUCTION

The Bay Area Air Quality Management District (the "District") violated the California Environmental Quality Act ("CEQA") by segmenting its analysis of multiple actions that collectively comprise the District's Refinery Project. CEQA demands unified review of "the whole of the action," and a series of actions undertaken to attain the same objective constitutes a single CEQA project. (*Tuolumne County Citizens for Responsible Growth, Inc. v. City of Sonora* (2007) 155 Cal.App.4th 1214, 1226-27) (hereinafter *Tuolumne County*).) The District admits that it conceived, developed, and adopted the Phase 2 Rules[1] as part of a broader, unified effort that encompasses at least seven separate rules[2] that are collectively designed to achieve a concrete, common objective: tracking and reducing refinery emissions by 20%. (Compl. at 4:24-27, Answer at 3:21.) Under *Tuolumne County* and core CEQA precepts, the District violated CEQA when it segmented its analysis of the Phase 2 Rules and adopted them in isolation, without any consideration of other actions taken by the District to achieve the same unified objective. (*Tuolumne County*, 155 Cal.App.4th at1226-27; see also Answer at 6:15-18, District admitting that relevant rules "have been analyzed separately under CEQA".)

Rather than address Petitioners' segmentation argument head-on, the District attempts to avoid the implications of *Tuolumne County* by arguing that Petitioners' claims "lack[] a predicate project" (Resp. at 10)—in essence, arguing that Petitioners' complaint is with the District's larger policy objectives, rather than a concrete CEQA project. The District misstates Petitioners' complaint. Petitioners have not challenged any generalized public policy, or even the specific objective that the Refinery Project attempts to achieve; rather, Petitioners object to the District's *implementation* of a specific objective (a 20% reduction in refinery emissions) in a manner that circumvents CEQA. The

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[1] Regulation 12, Rule 15 ("Rule 12-15") and Regulation 9, Rule 14 ("Rule 9-14"). The District refers to these rules as the "Challenged Rules."

[2] The rules challenged here represent the second phase of rulemaking. The first phase included three rules: Regulation 6, Rule 5 ("Rule 6-5"), Regulation 8, Rule 18 ("Rule 8-18"), and Regulation 11, Rule 10 ("Rule 11-10"). This first phase also was challenged by certain petitioners in this case. (*See* Valero et al. v. BAAQMD, Case No. N16-0095). In addition to the five rules adopted during the first two phases, the District has proposed at least two additional rules as part of the Refinery Project and is considering several more.

District has expressly conceded that the Phase 2 Rules "are among several that have been publicly discussed as steps towards achieving the 20% goal of the Refinery Strategy." (Resp. at 1.) And yet nowhere has the District collectively evaluated the impacts of each step *as a whole*. Instead, the District elected to develop and adopt these rules serially, and then claim that its serial adoption justifies treating each such rule as a separate CEQA "project."

The District also asserts that the alleged "independent utility" of the Phase 2 Rules should insulate them from CEQA's requirement to review the "whole of the action." But "[t]heoretical independence is not a good reason for segmenting the environmental analysis of the two matters." (*Tuolumne County*, 155 Cal.App.4th at 1230.) No amount of Monday morning quarterbacking can alter the basic fact that the Phase 2 Rules—along with the rest of the District's "suite of regulations"—were conceived and adopted to achieve a common, specific, and targeted objective.

In addition to violating CEQA, the District exceeded its authority when it attempted to compel refineries to report (i) their confidential "crude slate" composition, and (ii) cargo carrier emissions. It is black-letter law that "administrative agencies have only the powers conferred on them" and "may not act in excess of those powers." (*Am. Fed'n of Labor v. Unemployment Ins. Appeals Bd.* (1996) 13 Cal.4th 1017, 1042, n.9, citing *Ferdig v. State Personnel Bd.* (1969) 71 Cal.2d 96, 103-04.) Here, the District lacks *any* express authority to collect crude slate data or regulate cargo carriers, and existing state and federal laws preempt the District's attempts to regulate in these fields.

The District attempts to avoid preemption by misconstruing the scope of its authority and the law of preemption. For example, the District argues that its crude slate requirements are authorized because the District's procedures provide similar protections as the state law that already regulates crude slate reporting—which also happens to grant exclusive authority over crude slate data to another agency. But even if this characterization were correct (which it is not), preemption means that the District cannot regulate in this area *at all*—not that it may regulate as long as it hews closely enough to the statutory powers granted to another agency. (See *Sherwin-Williams Co. v. City of Los Angeles* (1993) 4 Cal.4th 893, 897 (agency action preempted when it "enters an area fully occupied by general law").) Similarly, the District argues that preemption does not bar its cargo carrier requirements by asserting that it is not regulating cargo carriers at all—it is merely holding refineries responsible for cargo carrier emissions. But the District cannot do indirectly what it lacks authority to do directly: it cannot compel refineries to "regulate" cargo carriers when it cannot do so itself.

The District has failed to demonstrate its compliance with California law and its authority to adopt core provisions of Rule 12-15. Petitioners respectfully ask this Court to enforce CEQA, find crude slate and cargo carrier provisions preempted, and order the District to vacate Rule 12-15.

II. THE DISTRICT HAS FAILED TO JUSTIFY ITS ILLEGAL SEGMENTATION OF THE REFINERY PROJECT UNDER CEQA

A. The Phase 2 Rules Are Part of a Larger CEQA Project Requiring Unified Review.

The critical facts here are simple. In late 2014, the District adopted Resolution 2014-07, which established the specific, defined objective of tracking refinery emissions (in part through Rule 12-15) and reducing those emissions by 20%. (AR Doc. 194, at 004394-95.) To implement the Resolution's objective, District staff developed a unified, multi-phase approach that it labeled as its "Refinery Emission Reduction Strategy." (AR Doc. 161, at 004069-70; see also AR Doc. 694, at 011575-83 (agenda for "Refinery Emissions Reduction Strategy Kick Off Meeting").) As the concrete regulatory actions flowing from this strategy, the District developed a coordinated set of refinery-focused rules, to be adopted in several phases, that *together* would achieve the Resolution's objective. (AR Doc. 161, at 004066-70 (describing approach); AR Doc. 147, at 003909-12 (identifying "phases" of Refinery Project).) These rules—including the Phase 1 Rules, the Phase 2 Rules, and other pending rules—collectively constitute the District's Refinery Project as "various steps which taken together obtain an objective." (*Tuolumne County*, 155 Cal.App.4th at 1226-27.) The District violated CEQA when it segmented its analysis by evaluating each rule separately and expressly disclaiming any obligation to consider the impacts of the Refinery Project as a whole. (See generally AR Docs. 15, 16.)

The District attempts to avoid this conclusion by arguing that the Refinery Project is not actually a single "project" under CEQA. The District acknowledges that the adoption of the Phase 2 Rules was an "activity" that qualified as a "project" under CEQA,[3] but then argues that these rules

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[3] Compl. 17:13-16, Answer 8:26. Indeed, the District could not argue otherwise, as the adoption of environmental rules has long been acknowledged to trigger CEQA. *See, e.g., Cal. Unions for Reliable Energy v. Mojave Desert Air Quality Mgmt. Dist.* (2009) 178 Cal.App.4th 1225, 1240, citing *Wildlife*

cannot be considered the same CEQA project, because while they were each designed to achieve a common purpose, this purpose was simply a "policy goal," and not a CEQA project in and of itself. (Resp. at 6:23-25 ("What unifies the Challenged Rules is not anything that arguably meets the definition of a CEQA 'project,' but rather only the statement of a policy goal.").)

The District's argument is essentially this: in order for the Refinery Project rules to qualify as the same CEQA "project," they would themselves have to implement another, larger CEQA "project." This assertion goes far beyond what CEQA demands. All actions "taken together" to achieve a single "objective" are considered a single CEQA project—regardless of the nature of that objective, or whether the objective itself is an independent CEQA "project." A "policy goal" is, as the District asserts, inchoate and amorphous: it is not an "activity" with direct and foreseeable impacts, and so a policy goal or objective—standing alone—is not subject to CEQA. Petitioners did not challenge the Board's 2014 Resolution for precisely this reason. A CEQA "project," on the other hand, is the specific activity or set of activities that *implement* a given objective.

The 2014 Resolution established a well-defined and measurable objective (or "policy goal," as the District puts it): to track and reduce refinery emissions by 20%. Petitioners agree that the 2014 Resolution itself is not an "activity" challengeable under CEQA, because it merely established an objective and it did not "commit the agency to a definite course of action." (See Pub. Res. Code § 21080(a); CEQA Guidelines § 15352(a).) But when the District promulgated the Phase 1 and Phase 2 Rules, it transitioned from setting an objective to *implementing* that objective by adopting a set of rules—which *is* an "activity" subject to CEQA. (*Id.*) And because those rules are each "various steps taken together" to *achieve the same policy goal*—the same "objective"—they constitute a single CEQA project. (*Tuolumne County*, 155 Cal.App.4th at 1226-27; Cal. Code Regs., tit. 14, § 15378(a); *Bozung v. LAFCO* (1975) 13 Cal.3d 263, 283-84.) As the Court of Appeal has observed:

> CEQA's conception of a project is broad, and the term is broadly construed and applied in order to maximize protection of the environment. This big picture approach to the definition of a project (*i.e.*, including "'the whole of an action'") prevents a proponent or a public agency from avoiding CEQA requirements by dividing a project into smaller

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Alive v. Chickering (1976) 18 Cal.3d 190, 206; *Plastic Pipe & Fittings Assn. v. Cal. Bldg. Standards Com.* (2004) 124 Cal.App.4th 1390.)

> components which, when considered separately, may not have a significant environmental effect. That is, the broad scope of the term "project" prevents "the fallacy of division," which is the "overlooking [of a project's] cumulative impact by separately focusing on isolated parts of the whole." Environmental considerations may not be submerged by chopping a single CEQA project into smaller parts for piecemeal assessment.

(*Nelson v. County of Kern* (2010) 190 Cal.App.4th 252, 271 (citations omitted).)

The District's approval of multiple refinery regulations to achieve the common, specific, and targeted objectives of the 2014 Resolution is "an activity" that will cause a physical change in the environment and is subject to CEQA. (Pub. Res. Code § 21065.) The core issue is whether the scope of that CEQA project is limited to individual regulations, as the District alleges, or whether it includes the entire multi-phase "Refinery Project", as Petitioners assert. *Tuolumne County* and its progeny establish that the correct answer is the latter: under CEQA, a project must include ***all*** of the "various steps which taken together obtain an objective." (*Tuolumne County*, 155 Cal.App.4th at 1226-27 (quotation omitted).) The District violated this core principle when it segmented its review of the individual Refinery Project rules.

B. The Alleged "Independent Utility" of the Phase 2 Rules Does Not Justify the District's Piecemeal Review of the Refinery Project.

The District does not contest the integrated nature of the rules it has conceived and adopted as part of its Refinery Strategy; nor does it contest the holding of *Tuolumne County.* Instead, the District argues that the alleged "independent utility" of the Phase 2 Rules somehow insulates them from CEQA review. (Resp. at 7:9-8:3.) Specifically, the District asserts that each of the Phase 2 Rules has some degree of "independent utility" that, in the District's words, "has been articulated as an indication that separate CEQA review of separate actions is appropriate." (Resp. at 7:16-18). In support of this proposition, the District cites two cases: *Del Mar Terrace Conservancy Inc. v. City Council of San Diego* (1992) 10 Cal.App.4th 712 (hereinafter *Del Mar Terrace*)[4] and *Banning Ranch Conservancy v. City of Newport Beach* (2012) 211 Cal. App. 4th 1209. Neither case supports the District's argument.

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[4] *Del Mar Terrace* also is not directly controlling here because it addressed the required environmental review for highway projects. (*Del Mar Terrace*, 10 Cal.App.4th at 732.) As the court made clear, the version of the "independent utility" test it applied was derived from federal case law and "is specific to

Del Mar Terrace is inapposite to the facts presented in this case. *Del Mar Terrace* involved the sufficiency of an Environmental Impact Report ("EIR") related to a roadway project in Carmel, California known as the "56 West" project. (*Del Mar Terrace*, 10 Cal.App.4th at 719.) The 56 West project was one of five roadway projects that the local government sought to implement in phases; future anticipated projects included the 56 East project, followed by a possible four-mile Future Urbanizing Area ("FUA") project to link the 56 East and 56 West projects. (*Id.* at 731.) The EIR for the 56 West project evaluated the "worst-case" environmental impacts that might occur if the FUA were developed, but did not comprehensively analyze all aspects of the FUA, since its development was highly speculative. (*Id.* at 721-23, 731.) The petitioners nevertheless argued that the EIR for the 56 West project was insufficient because it did not include a complete analysis of the *potential* FUA project. (*Id.*) The court rejected this challenge, finding the EIR sufficient because the 56 West project was designed to independently relieve congestion in a certain area, because there was not yet any "defined project to [expand] SR 56 through the . . . FUA," and because the EIR did, in fact, evaluate the worst-case impacts associated with the potential future development of the FUA. (*Id.* at 732-37.)

None of the considerations of *Del Mar Terrace* apply here. The Refinery Project rules—including the Phase 2 Rules—were not developed in isolation to achieve independent objectives. As the District admits, they were developed as part of the District's unified strategy to achieve the mandates set out in Board Resolution 2014-07.[5] Nor are the Refinery Project rules highly speculative, uncertain, or contingent on future events: the District's Board has already approved the scope and goals of the Refinery Strategy, and the District has already promulgated five rules (including the Phase 2 Rules) as the first phases of its Refinery Project (while improperly evaluating each of those rules in isolation). Perhaps most importantly, the District has made *no* attempt to evaluate the "worst-case"

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roads." (*Del Mar Terrace*, 10 Cal.App.4th at 732 (citing and discussing *Daly v. Volpe* (9th Cir. 1975) 514 F.2d 1106).) There is no roadway project at issue in this case.

[5] The connectivity of these rules is further reinforced by the District's stated intention to use data collected through Rule 12-15 to implement proposed Rule 12-16 and proposed Rule 13-1 (which is effectively a substitution for, or an extension of, the previously-proposed Rule 12-16). In fact, the District concedes that Rule 12-16, as previously proposed, was "functionally dependent on the version of Rule 12-15 proposed at the same time." (Resp. at 7:25-28.)

impacts associated with future Refinery Project actions. Unlike the EIR prepared in *Del Mar Terrace*, the Negative Declarations issued in conjunction with the Phase 2 Rules expressly limit their analysis to each individual rule and disclaim *any* obligation to consider the cumulative impacts arising from its Refinery Project as a whole or any other related rule or action. (AR Doc. 15 (negative declaration for Rule 9-14); AR Doc. 16 (negative declaration for Rule 12-15).)

In relying on *Del Mar Terrace*, the District conflates the "independent utility" test with CEQA's requirement to evaluate "integral" activities as part of the same CEQA project. (See *No Oil, Inc. v. City of Los Angeles* (1987) 196 Cal.App.3d 223; *Sierra Club v. West Side Irrigation Dist.* (2005) 128 Cal.App.4th 690, 698.) But any argument that the Challenged Rules can "stand alone" does not remove them from CEQA's requirement to evaluate the "whole of the action" because:

> when one activity is an integral part of another activity, the combined activities are within the scope of the same CEQA project. [Parties go] astray, however, by inverting this principle. The idea that all integral activities are part of the same CEQA project does not establish that *only* integral activities are part of the same CEQA project.

(*Tuolumne County*, 155 Cal.App.4th at 1229 (emphasis added).) In other words, the "integral activities" concept does not contract the scope of CEQA—it expands it—and the "independent existence of the two actions cease[s] for purposes of CEQA" when both actions are steps towards a well-defined common objective. (*Id.* at 1231.)

The District fares no better with *Banning Ranch*. In that case, petitioners challenged an EIR adopted for the development of Sunset Ridge Park, in the City of Newport Beach, alleging that it wrongfully excluded consideration of "the pending residential and commercial development on an adjacent property, Banning Ranch." (*Banning Ranch Conservancy*, 211 Cal. App. 4th at 1214.) The court rejected petitioners' claims, holding that the Banning Ranch development was not a "reasonably foreseeable consequence of the park." (*Id.*) In doing so, the court noted that "piecemealing case law defies easy harmonization" and grouped impermissible piecemealing cases into two general categories. (*Id.* at 1223.) According to the court, there may be improper piecemealing when:

- "the purpose of the reviewed project is to be the first step toward future development" (*Id.*, citing *Laurel Heights Improvement Ass'n v. Regents of Univ. of Cal.* (1988) 47 Cal.3d 376, and its line of cases); and also when

- "the reviewed project legally compels or practically presumes completion of another action." (*Banning Ranch Conservancy*, 211 Cal. App. 4th at 1214, citing *Nelson v. County of Kern*, 190 Cal.App.4th at 272, *Tuolumne County*, 155 Cal.App.4th at 1231, and related cases).

The *Banning Ranch* court went on to evaluate the petitioners' claims based only on the *first* type of piecemealing analysis (the "first step" doctrine of *Laurel Heights*), ultimately concluding that there was no piecemealing because Banning Ranch and the park had "different project proponents", "serve different purposes", and were not dependent on each other for the fulfillment of any larger goal. (*Banning Ranch,* 211 Cal. App. 4th at 1223.) None of those considerations apply here. In this case, the record amply demonstrates a series of coordinated actions, taken by the same project proponent (the District), to collectively achieve a common, larger goal (a 20% reduction in refinery emissions).

The *Banning Ranch* court did not even evaluate the second type of piecemealing, where one action "practically presumes completion of another action." (*Id.* at 1223.) That is the scenario presented by the Refinery Project: each of the Phase 1 and Phase 2 Rules were jointly developed and adopted by the District in a coordinated fashion that plainly "presumes completion" of other actions (*i.e.*, the contemporaneous or later adoption of the other rules) in order to achieve the District's overarching objective of reducing refinery emissions by 20%. The District made this quite clear in numerous internal documents and public presentations that specifically describe the Refinery Project as comprised of multiple phases, each with several individual rules, which build upon each other to achieve the 20% reduction objective. (See, e.g., AR Doc. 147, at 003909, 003911; AR Doc. 30, at 001090-91.) Contrary to the District's argument, *Banning Ranch* is entirely consistent with *Tuolumne County*, and both cases reject the idea that theoretical independence can justify the segmentation of related actions.

The concept of "independent utility" was fully considered in *Tuolumne County*. There, Lowe's (the project proponent) argued that its construction of a store and a road realignment were independent actions and did not require unified CEQA analysis because "they could 'be implemented independently of each other.'" (*Tuolumne County*, 155 Cal.App.4th at 1229.) The court squarely rejected that argument, noting that "[Lowe's] places too much importance on theoretical possibilities at the expense of what actually is happening." (*Id.* at 1230.) The same is true here: while the District argues that the

Phase 2 Rules could "stand alone functionally" and are not "dependent" on other Refinery Project rules (Resp. at 7:11-12), that simplistic statement fails to reflect "what is actually happening" in this case—namely, the coordinated development, adoption, and implementation of a suite of rules all aimed at achieving a single objective. (*Tuolumne County,* 155 Cal.App.4th at 1230 ("Theoretical independence is not a good reason for segmenting the environmental analysis of the two matters").) The District cannot hide behind the theoretical independence of Rule 12-15 and Rule 9-14 to argue that they are exempt from CEQA's mandate to review "the whole of the action."

"[W]here distinct actions are closely related to same overall objective, or if success of the overall objective depends on the inclusion of certain action, the distinct actions are viewed as parts of a larger whole—the same [CEQA] project." (*Nelson,* 190 Cal.App.4th at 271, citing *Tuolumne County,* 155 Cal.App.4th at 1225–1231; see also *Tuolumne County,* 155 Cal.App.4th at 1226.) The District admits that its Refinery Project rules each represent a component of its unified strategy to track and reduce refinery emissions by 20%. (Compl. at 4:24-27, Answer at 3:21). Further, no single Refinery Project rule is sufficient on its own to achieve that objective. (See AR Doc. 2, at 000561 (discussing additive contributions of various rules towards the 20% reduction objective).) Notwithstanding the clear and well-documented relationship of each Refinery Project rule to the "same overall objective," the District failed to prepare an EIR for the Refinery Project *as a whole*.[6] Instead, the District reviewed each of the Phase 2 Rules independently, concluded that each rule had no significant environmental impact, and adopted individual negative declarations. (AR Docs. 15, 16.) In doing so, the District "chopped up" the Refinery Project and violated CEQA.

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[6] The District's recent actions further underscore the integrated and ongoing nature of the Refinery Project. In March 2017, the District published a draft EIR for Rules 12-16 and 11-18. (http://www.baaqmd.gov/~/media/files/planning-and-research/rules-and-regs/workshops/2017/reg-12-deir-pdf.pdf?la=en.) Previously, the District had combined its CEQA analysis for Rule 12-16 with Rule 12-15, but then severed that analysis when it adopted Rule 12-15. The District's uncoupling of Rule 12-15 from Rule 12-16, and subsequent reattachment of Rule 12-16 to Rule 11-18, reinforces the integrated nature of the District's Refinery Project rulemaking actions.

C. The District Cannot Avoid Its CEQA Obligations By Claiming Administrative Inconvenience.

The District complains that conducting a unified CEQA review for the Refinery Project would be "as a practical matter . . . perplexing." (Resp. at 10:18-19.) The District raises the specter of an agency tied in knots, stuck in an endless loop of CEQA reviews each time it engages in a new regulatory initiative. The District's argument is a strawman. Petitioners never argued that CEQA requires justification for the District's planning activities; Petitioners seek only a unified review of the impacts arising from the suite of regulations that the District *itself* identified as the mechanism by which it intended to implement the Refinery Strategy.[7] (See, e.g., AR Doc. 694, at 011575-83; *id.* at 011577-78; AR Doc. 161, at 004066-70; AR Doc. 147, at 003909-12; AR Doc. 56, at 002194.)

Nor is the District's Refinery Project aimed at a generalized public policy, such as "improving air quality," as the District seems to suggest. To the contrary, the District developed the Refinery Project to achieve the specific, targeted objectives it identified in the 2014 Resolution. The Phase 2 Rules are one of the steps needed to implement and achieve those specific and targeted objectives (in conjunction with the Phase 1 Rules, and additional future rules). At a minimum, the District could easily have conducted a comprehensive review of the two Phase 2 Rules and incorporated into that analysis the cumulative impacts associated with its already-adopted Phase 1 Rules—yet the District failed to undertake even this minimal additional effort.

Projects often occur in multiple phases or components, but that does not excuse an agency from CEQA's mandate to evaluate "the whole of the action." (*Cal. Union for Reliable Energy v. Mojave Desert Air Quality Mgmt. Dist.* (2009) 178 Cal.App.4th 1225, 1242.) If the District were interested in finding "practical" solutions, CEQA provides clear paths to do so. For example, among other things the CEQA Guidelines provide that:

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[7] All projects have their origins in an idea or mandate, whether it is the District's Board resolution to reduce refinery emissions by 20%, or a corporate board resolution to build a new shopping center. In each case, numerous planning stages ensue, during which the project's proponents plan a path towards achieving their ultimate goal. For CEQA purposes, the culmination of that planning process is the approvals necessary for the project to proceed—approvals that trigger CEQA's requirement to assess the environmental impacts of the entire project. (See CEQA § 21065 (defining a CEQA "project" to include agency actions that have a direct or foreseeable indirect effect on the environment).)

> Where individual projects are, or a phased project is, to be undertaken and where the total undertaking comprises a project with significant environmental effect, the lead agency shall prepare a single program EIR for the ultimate project as described in Section 15168. Where an individual project is a necessary precedent for action on a larger project, or commits the Lead Agency to a larger project, with significant environmental effect, an EIR must address itself to the scope of the larger project. Where one project is one of several similar projects of a public agency, but is not deemed a part of a larger undertaking or a larger project, the agency may prepare one EIR for all projects, or one for each project, but shall in either case comment upon the cumulative effect.

(CEQA Guidelines § 15165.) As the Guidelines make clear, the fact that a project may occur over time or in multiple phases does not excuse an agency from evaluating all project actions in a comprehensive manner. (*Id.*) Instead, CEQA expressly provides various mechanisms to facilitate evaluation of multi-phase projects, which discredit the District's concerns.

For example, the District could have prepared a program EIR. (CEQA Guidelines § 15168.) Among other things, a program EIR is appropriate for "actions that can be characterized as one large project" and are "logical parts in the chain of contemplated actions." (*Id.*) Other mechanisms to aid agencies in multi-component projects include "tiering" EIRs (CEQA Guidelines § 15152), "staging" EIRs (CEQA Guidelines § 15167), and creating a "master" EIR (CEQA Guidelines §§ 15175-15179.5.) The common thread running through each of these options is that agencies are not excused from evaluating cumulative impacts arising from "the whole of the action" merely because the project may occur in multiple stages or over an extended timeline.

The District is well aware of these options—its own CEQA Guidelines specifically contemplate the use of these procedures. Among other things, the District's Guidelines provide that:

> Lead agencies may analyze and mitigate the significant effects of greenhouse gas emissions at a programmatic level, such as in a general plan, a long range development plan, or a separate plan to reduce greenhouse gas emissions. Later project-specific environmental documents may tier from and/or incorporate by reference that existing programmatic review. Project-specific environmental documents may rely on an EIR containing a programmatic analysis of greenhouse gas emissions as provided in section 15152 (tiering), 15167 (staged EIRs) 15168 (program EIRs), 15175-15179.5 (Master EIRs), 15182 (EIRs Prepared for Specific Plans), and 15183 (EIRs Prepared for General Plans, Community Plans, or Zoning).

(BAAQMD, CEQA Guidelines at 4-7 (2012).)[8] Emphasizing this point, the District recently published on its website a draft program EIR for its 2017 Clean Air Plan, explaining that:

> A program EIR also plays an important role in establishing a structure within which CEQA reviews of future related actions can be effectively conducted. This concept of covering broad policies in a program EIR and incorporating the information contained therein by reference into subsequent EIRs for specific projects is known as "tiering" (CEQA Guidelines §15152). A program EIR will provide the basis for future environmental analyses and will allow project-specific CEQA documents to focus solely on the new effects or detailed environmental issues not previously considered.

(BAAQMD, Draft 2017 Clean Air Plan § 1.2.2 (Feb. 17, 2017).)[9]

The District's organization of its own regulations is a matter of administrative convenience—there is no necessity for the District to adopt regulatory requirements separately. In effect, the District argues that it should be able to package its regulatory efforts however it likes, and to evaluate each regulatory action or rule in complete isolation from all others. Taken to its logical conclusion, the District's argument would permit it to segment any regulatory effort into many smaller regulations, minimize the perceived impacts by reviewing each component in isolation, and avoid a cohesive review of the "whole of the action." This outcome would make the District the sole arbiter of whether and to what extent CEQA review is required for any rulemaking action, and is exactly what CEQA prohibits. (CEQA Guidelines § 15378(a); *Bozung*, 13 Cal.3d at 283-84; *Nelson*, 190 Cal.App.4th at 271; *Laurel Heights Improvement Ass'n,* 47 Cal.3d at 396.)

Because each rule adopted as part of the Refinery Project is part of a cohesive plan to achieve a single, defined objective, the Phase 2 Rules—along with the previously adopted Phase 1 Rules—collectively form a single CEQA project. (*Tuolumne County*, 155 Cal.App.4th at 1226.) The District violated CEQA when it adopted these rules without analyzing them in concert, and it continues to violate CEQA by adopting and proposing new Refinery Project rules in isolation. (*Id.*; *Laurel Heights Improvement Ass'n,* 47 Cal.3d at 396.)

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[8] http://www.baaqmd.gov/~/media/files/planning-and-research/ceqa/baaqmd-ceqa-guidelines_final_may-2012.pdf?la=en.

[9] http://www.baaqmd.gov/~/media/files/planning-and-research/plans/2017-clean-air-plan/2017plandrafteirpdf-pdf.pdf?la=en.

III. THE DISTRICT HAS FAILED TO DEMONSTRATE THAT IT HAS AUTHORITY TO COLLECT CRUDE SLATE DATA OR REGULATE CARGO CARRIERS

Two core provisions of Rule 12-15 are preempted by state and federal law. First, California's Petroleum Industry Information Reporting Act ("PIIRA") occupies the field with respect to the collection of "crude slate" information, and grants *exclusive* authority to collect such information to the California Energy Commission ("CEC"). (Pub. Res. Code §§ 25350-25366; Cal. Code Regs., tit. 20 §§ 1361-1371.) Second, the District lacks any express authority to regulate cargo carriers (such as marine vessels and trains) and several state and federal laws preempt its efforts to do so. The District brushes these issues aside, asserting that Petitioners' concerns with respect to PIIRA preemption are based only on what it calls "minor procedural variations," and that the District is not actually regulating cargo carriers by requiring refineries to do so—an argument that both the D.C. Circuit and the U.S. Environmental Protection Agency ("EPA") have rejected.

The Supremacy Clause of the United States Constitution requires state and local laws to yield to federal law. (U.S. Const., art. VI, cl. 2; *Gibbons v. Ogden* (1824) 22 U.S. 1, 2 (federal laws "are supreme, and the State laws must yield to that supremacy").) The Supremacy Clause gives rise to "well-known principles of pre-emption." (*Douglas v. Seacoast Products, Inc.* (1977) 431 U.S. 265, 272.) And "when Congress has unmistakably ordained that its enactments alone are to regulate a part of commerce, state laws regulating that aspect of commerce must fall." (*Jones v. Rath Packing Co.* (1977) 430 U.S. 519, 525 (internal quotations and annotations omitted).) The California Supreme Court has set forth similar preemption principles, holding that local law is preempted when it (i) conflicts with a state law, (ii) duplicates state law, (iii) contradicts state law, or (iv) "enters an area fully occupied by general law, either expressly or by legislative implication." (*Sherwin-Williams Co.*, 4 Cal.4th at 897-98.) The District's adoption of crude slate and cargo carrier provisions in Rule 12-15 falls squarely within these bedrock principles, and is void. (See generally *County of San Diego v. Bowen* (2008) 166 Cal.App.4th 501 (agency action is void if preempted by an act of the Legislature).)

A. PIIRA Preempts Rule 12-15's Crude Slate Reporting Requirements for Two Distinct Reasons.

The crude slate reporting provisions of Rule 12-15 are preempted for two distinct reasons. First, when it enacted PIIRA the California Legislature fully occupied the field of reporting petroleum and crude oil information. Second, and independently, Rule 12-15 conflicts with and undermines core protections of PIIRA enacted by the Legislature to protect highly sensitive information. In its Response, the District asserts that Petitioners' arguments are based only on "minor procedural variations" between PIIRA and Rule 12-15 with respect to the treatment of confidential data. (Resp. 21:26-22:1). That statement entirely ignores basic preemption principles, the breadth and scope of PIIRA, the plain intent of the Legislature, and the cavalier approach the District has taken with respect to highly sensitive information protected by PIIRA.

1. PIIRA Occupies the Field of Crude Oil Reporting and Rule 12-15's Intrusion Into That Field is Unauthorized and Illegal.

PIIRA was intended by the Legislature as the exclusive mechanism for collecting crude oil data in California. The name alone—the "Petroleum Industry Information Reporting Act"—plainly indicates the content of the law and its scope, and PIIRA expressly provides that it was established for the purpose of collecting "information and data concerning ***all aspects*** of the petroleum industry." (Pub. Res. Code § 25350(c).) Notably, PIIRA grants authority to collect such data to a single state agency—the CEC. The Legislature granted no other agency co-extensive authority. The *only* agency to which the CEC may even disclose crude slate data is the California Air Resources Board ("ARB") and then only "if [ARB] agrees to keep the information confidential." (Pub. Res. Code § 25364(g).) There is no mention of the District (or any other air district) in PIIRA—an exclusion that, by its terms, prohibits transmission of crude slate data by the CEC to the District.

PIIRA is comprehensive, covering a wide range of entities (including refineries), feedstocks, blendstocks, petroleum products, and other related data. (See generally Pub. Res. Code § 25354.) Under PIIRA, refineries submit weekly, monthly, and annual data on a wide range of parameters specified in CEC's implementing regulations. (Cal. Code Regs. tit. 20 §§ 1361-1371, App. A.) The Legislature tasked CEC with analyzing and interpreting this data for, among other things, "economic and environmental impacts" related to petroleum supply and "efforts of the petroleum industry to expand refinery capacity and to make acquisitions of additional supplies of petroleum and petroleum products." (Pub. Res. Code § 25356(a)(2),(7).) In short, PIIRA establishes an extensive state-wide scheme for collecting and analyzing all manner of data related to crude oil, petroleum products, blendstocks, and other related substances.

"If the subject matter or field of the legislation has been fully occupied by the state, there is no room for supplementary or complementary local legislation." (*Cal. Water & Tel. Co. v. Los Angeles County* (1967) 253 Cal.App.2d 16, 27.) Had the Legislature intended to grant the District authority to collect crude slate data, it could easily have done so when it amended PIIRA over the years, but it chose not to. Indeed, the Legislature has considered—*and expressly rejected*—amendments to PIIRA that would have allowed the CEC to disclose information it collects under PIIRA to "other governmental agencies which have a need for that information related to their official functions." (See Assem. Bill No. 3777 (1991-1992 Reg. Sess.), amended by the Senate on June 3, 1992.) The Legislature did *not* enact this provision, and PIIRA continues to prohibit disclosure to the District. PIIRA occupies the field of petroleum and crude slate reporting in California—to the exclusion of any regulations adopted by the District—and preempts the crude slate requirements of Rule 12-15.

2. Rule 12-15 Conflicts With and Undermines PIIRA.

Even if PIIRA did not entirely occupy the field of crude slate reporting, the District's efforts to regulate in this area directly conflict with and undermine vital provisions of PIIRA intended to protect sensitive information and California consumers. As Petitioners have explained, PIIRA contains extensive provisions aimed at preventing the disclosure and improper use of petroleum data. (See Pet'rs' Br. 23:5-26:2.) The District attempts to minimize these concerns, pointing to what it calls are mere "minor procedural variations" between Rule 12-15 and PIIRA. (Resp. 21:28.) But at the same time, the District concedes that, with respect to confidentiality:

> The most substantial difference between PIIRA and the Air District's procedures appears to be that, under PIIRA, the CEC can decide not to release information it deems confidential (which decision presumably can be challenged in court). The Air District's procedures, by contrast, require it to release requested information unless a court injunction is obtained. . . *Under Air District procedures, the Refineries must be proactive in seeking judicial relief. Under PIIRA, the Refineries may be reactive.*

(Resp. 24:20-27 (emphasis added).) Notwithstanding its attempts to minimize this issue, the District seems to *agree* with Petitioners that Rule 12-15 completely inverts the confidentiality and disclosure requirements carefully considered by the Legislature and included in PIIRA.

The District's statement also understates the significant differences between PIIRA and Rule 12-15. PIIRA expressly prohibits the CEC from utilizing non-aggregated data for ***any*** purpose other than the statistical analysis, and from disclosing that information ***to anyone other than CEC members and staff***. (Pub. Res. Code § 25364(f); see also Cal. Code Regs. tit. 20 § 1370(a).) Rule 12-15 contains no such protections; indeed, the District admits that the *only* protections afforded to crude slate data collected under Rule 12-15 derive from California's generalized Public Records Act, which does not—in the District's own words—"address procedures for determining what qualifies as trade secret." (Resp. 23:5-10.)

It is readily apparent that by adopting Rule 12-15, the District intends to collect crude slate data similar or identical to that collected under PIIRA, while affording it none of the protections ensured by PIIRA. When "'local legislation conflicts with state law, it is preempted by such law and is void.'" (*Sherwin-Williams Co.* 4 Cal.4th 893, 897, quoting *Candid Enterprises, Inc. v. Grossmont Union High School Dist.* (1985) 39 Cal.3d 878, 885; accord, *IT Corp. v. Solano County Bd. of Supervisors* (1991) 1 Cal.4th 81, 90; *People ex rel. Deukmejian v. County of Mendocino* (1984) 36 Cal.3d 476, 484; *Lancaster v. Municipal Court* (1972) 6 Cal.3d 805, 807.) A local air district cannot subvert the will of the Legislature by adopting regulations that entirely circumvent the protections granted by the Legislature. "If the preemption doctrine means anything, it means that a local entity may not pass an ordinance, the effect of which is to completely frustrate a broad, evolutional statutory regime enacted by the Legislature." (*Fiscal v. City and County of S.F.* (2008) 158 Cal.App.4th 895, 911.) Because the crude slate provisions of Rule 12-15 frustrate the goals and protections of PIIRA, they are preempted by PIIRA and void. (See *County of San Diego,* 166 Cal.App.4th 501.)

3. The District Has No Authority to Collect Crude Slate Data.

In a further effort to justify the crude slate provisions of Rule 12-15, the District points to two highly generalized provisions in the H&S Code, neither of which contain any express grant of authority to collect crude slate data, and neither of which operate to displace PIIRA.

The District cites H&S Code Sections 42303 and 41511 as its underlying grant of authority to collect crude slate data. But as the District concedes, its authority under these provisions is limited to "emissions" and "air contaminants." (See Resp. 16:7-25; H&S Code §§ 42303, 41511.) Rule 12-15, on the other hand, directly compels the disclosure of highly confidential raw material and feedstock composition. While the District now argues that collecting crude slate data is a "reasonable measure" for assessing air pollution (Resp. 16:5-20:11), this litigation position directly conflicts with the District's prior statements in the record that a refinery's crude slate has an "uncertain[]" relationship to "refinery air emissions" (AR Doc. 2, at 000291).[10] The District is entitled to no deference on whether its choice was "reasonable" because "[a] court does not . . . defer to an agency's view when deciding whether a regulation lies within the scope of the authority delegated by the Legislature." (*Yamaha Corp. of Am. v. State Bd. of Equalization* (1998) 19 Cal.4th 1, 11, n. 4) (citation and quotation omitted).)

More importantly, the extremely generalized provisions of the H&S Code cited by the District do not allow the District to circumvent PIIRA. When it enacted PIIRA, the Legislature expressly granted exclusive authority to the CEC with respect to the collection of data related to crude oil, petroleum products, blendstocks, and related items. The Legislature has chosen ***not*** to grant the District any similar authority and "a specific statute will not be controlled or nullified by a general one." (*Morton v. Mancari* (1974) 417 U.S. 535, 550-51; see also *Sherwin-Williams Co.*, 4 Cal.4th at 897 ("If otherwise valid local legislation conflicts with state law, it is preempted by such law and is void.").)[11]

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[10] The District also points to the New Source Review ("NSR") program as evidence of legislative intent to allow the District to collect crude slate data. (Resp. 17:11-21.) The District fails to note, however, that the federal definitions incorporated into the District's NSR program do *not* consider most changes in fuels and raw materials to be "modifications" that would trigger NSR. *See* 40 C.F.R. § 51.165(a)(1)(v)(C). Furthermore, most refineries are designed to handle a particular crude oil blend (within narrow parameters), and changes to that configuration would necessitate a physical redesign of certain refinery components, which is outside the scope of the NSR program. (See *Helping Hand Tools v. U.S. Environmental Protection Agency* (9th Cir. 2016) 848 F.3d 1185 (discussing NSR program and its scope).)

[11] Petitioners also have challenged other findings made by the District with respect to Rule 12-15, including findings that the rule is necessary and does not duplicate or interfere with requirements imposed by state or federal law. (See Pet'rs' Br. 17:1-21:2; see also H&S Code § 40727(b)(1),(4)-(5).) The District concedes that its findings are subject to judicial review based on an "arbitrary and

B. The District Concedes That it Has No Authority To Regulate Cargo Carriers.

The District has not even responded to Petitioners' preemption arguments related to the cargo carrier requirements of Rule 12-15. Instead, the District attempts to avoid preemption by arguing that Rule 12-15 does not actually regulate cargo carriers. In effect, the District's position is that even though it lacks authority to regulate or collect emissions data from cargo carriers directly, it may regulate them indirectly by compelling refineries to "estimate" cargo carrier emissions through "observations by refinery staff combined with assumptions regarding the type of equipment being used by cargo carriers." (Resp. 26:28-27:2.)

This is a remarkable position. As the District concedes, the refineries cannot compel cargo carriers to provide them with emissions data, and "it is unknown at this point to what extent cargo carriers will cooperate with Refineries in providing emissions-related information to the air District." (Resp. at 25:18-20.) What the District seeks, then, is to have the refineries take a *guess* at cargo carrier emissions, report their guesses to the District, then be held legally accountable for the accuracy of those guesses.[12]

The District's approach to cargo carrier emissions is at best arbitrary and capricious. Given the complete lack of any mechanism by which the refineries can compel accurate data from unrelated third parties, there is simply no way to ensure that "guesstimates" provided by refineries will provide information that is sufficiently accurate to support any future emissions analysis or regulatory efforts by the District. Further, should the District pursue enforcement against the refineries for insufficiently accurate guesstimates, such a claim would raise significant due process concerns, given that the District

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capricious" standard. (Resp. 12:2-24.) To survive that standard, the District must support its findings with substantial evidence in the record that is "reasonable, credible, and of solid value." (*Plastic Pipe and Fittings Assn.*, 124 Cal. App. 4th at 1407.) In its Response, the District cites approximately 24 pages of two documents in the Administrative Record in support of its conclusions. (See Resp. 12:25-21:19). Petitioners have previously argued that the Record contains little more than conclusory assertions that do not support the District's mandatory findings under the H&S Code. (Pet'rs' Br. 17:1-21:2) Petitioners assert that the record speaks for itself on these issues, and fails to satisfy the District's obligation to make H&S Code findings based on "substantial evidence."

[12] Tellingly, Petitioners are unaware of any District efforts to require other facilities or industries to gather and report emissions data related to cargo carriers visiting those facilities.

has provided no means by which refineries can compel the production of the information for which they are to be held accountable.

Of even greater concern, the District cannot compel a refinery to do what the District itself cannot. As the D.C. Circuit has held under the Clean Air Act, marine vessel emissions cannot be attributed to a stationary source like a refinery. (*NRDC v. EPA* (D.C. Cir. 1984) 725 F.2d 761, 764 ("it is entirely implausible that a vessel's 'to-and-fro' emissions could be attributed to a marine terminal owner under any approach that the [Clean Air Act] would tolerate."). Similarly, EPA has concluded that "[t]he 'to and fro' emissions and 'hotelling' emissions from the vessels are associated with the normal seagoing activities of the vessels and not with the industrial activities associated with the port[.]" (See AR Doc. 18, at 000871, citing Letter from C. Sheehan (EPA Region 6) to M. Cathey, El Paso Energy, and D. Dutton, Akin, Gump (Oct. 28, 2003).) And, in the absence of express EPA authorization, the Clean Air Act prohibits the District from regulating marine vessels. (*Pacific Merchant Shipping Assn. v. Goldstene*, (9th Cir. 2008) 517 F.3d 1108.)

The District's lack of authority in the context of trains is equally clear: the Interstate Commerce Commission Termination Act ("ICCTA") expressly preempts and prohibits the District from regulating rail carriers in any fashion. (49 U.S.C. § 10501(b).) That prohibition extends to the exact scenario presented here: the Ninth Circuit has previously rejected attempts by an air district to require a third-party entity to collect and report railroad emissions data. (*Assn. of Am. Railroads v. S. Coast Air Quality Mgmt. Dist.* (9th Cir. 2010) 622 F.3d 1094, 1098.) Just like the air district rules considered in *Assn. of Am. Railroads*, Rule 12-15 seeks to compel a third party (refineries) to undertake an activity (collecting and reporting railroad emissions) that the District itself is expressly *prohibited* from undertaking. *Assn. of Am. Railroads* squarely blocks the District's attempt to conduct an end-run around the ICCTA.

The District cannot delegate to Petitioners an activity the District itself lacks authority to undertake. And even if the District did have authority to regulate cargo carriers, any attempt to delegate that authority to Petitioners would run afoul of due process and the non-delegation doctrine. (See, e.g., *Carter v. Carter Coal Co*, (1936) 298 U.S. 238 (invalidating qualified legislative delegation of authority to private parties); *Assn. of Am. Railroads v. Dept. of Transp.* (D.C. Cir. 2016) 821 F. 3d 19 (invalidating certain delegations of authority to Amtrak based on due process concerns related to allowing Amtrak to effectively regulate or oversee a competitor in the marketplace).)

The District does not contest that it lacks authority to regulate cargo carriers. While it may prefer an emissions inventory containing cargo carrier data, the District cannot compel refineries to do what it lacks authority to do itself, at the risk of enforcement for failing to provide sufficiently accurate guesstimates. The cargo carrier provisions of Rule 12-15 are preempted and void. (*Am. Fed'n of Labor v. Unemployment Insurance Appeals Bd.* (1996) 13 Cal.4th 1017, 1042; *County of San Diego*, 166 Cal.App.4th 501.)

IV. CONCLUSION

For all of the foregoing reasons, this Court should grant the Petition and issue a writ of mandate finding Rule 12-15 preempted by state and federal law and requiring the District to: (i) vacate and set aside the Initial Study/Negative Declarations for Rules 12-15 and 9-14; (ii) comply with CEQA and H&S Code requirements in any future Refinery Project rulemaking; and (iii) vacate and set aside Rule 12-15.

Dated: April 11, 2017

Respectfully submitted,

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PROOF OF SERVICE

I, the undersigned, declare that I am employed in the County of San Francisco; I am over the age of eighteen years and not a party to the within entitled action; my business address is Beveridge & Diamond, P.C., 456 Montgomery Street, Suite 1800, San Francisco, CA 94104-1251.

On April 11, 2017, I served the following document(s): **PETITIONERS' REPLY BRIEF IN SUPPORT OF PETITION FOR WRIT OF MANDATE** on the interested party(ies) in this action.

Adan Schwartz
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The documents were served by the following means:

☒ BY ELECTRONIC TRANSMISSION: Based on an agreement of the parties to accept service by electronic transmission, I caused the documents to be sent to the person at the electronic notification address set forth above.

I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct.

DATED: April 11, 2017

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SUPERIOR COURT OF THE STATE OF CALIFORNIA

FOR THE COUNTY OF CONTRA COSTA

WESTERN STATES PETROLEUM ASSOCIATION; VALERO REFINING COMPANY—CALIFORNIA; TESORO REFINING & MARKETING COMPANY, LLC; and PHILLIPS 66 COMPANY,

Petitioners/Plaintiffs,

v.

BAY AREA AIR QUALITY MANAGEMENT DISTRICT and DOES 1 through 20, inclusive,

Respondents/Defendants.

Case No. N16-0963

PETITIONERS' BRIEF IN SUPPORT OF PETITION FOR WRIT OF MANDATE

(Code Civ. Proc §§ 1085, 1094.5)

CEQA CASE

APPENDIX A

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I. INTRODUCTION

In 2014, the Bay Area Air Quality Management District (the "District") adopted Resolution 2014-07, which defines several concrete objectives, including a "20% reduction in refinery emissions, or as much emissions reductions as are feasible . . . as expeditiously as possible" (the "Resolution"). (Admin. Record Doc. ("AR Doc.") 194, at 004394-95.) Shortly thereafter, District staff conceived of a "suite" of rules, developed in concert, that would work together to achieve the Resolution's objectives, an undertaking the District labeled as its "Refinery Emission Reduction Strategy." (AR Doc. 161, at 004069-70.) Two of those rules are challenged here: Regulation 12, Rule 15 ("Rule 12-15") and Regulation 9, Rule 14 ("Rule 9-14"). There is no dispute that Rules 12-15 and 9-14 were developed and adopted under the umbrella of the District's Refinery Strategy. (Answer at 6:4-7 (admitting that five rules, including Rule 12-15, were "characterized by the Air District as implementing different phases of the Refinery Strategy").)

Under the California Environmental Quality Act ("CEQA") [1], a series of actions undertaken to attain the same objective constitutes a single "project." (*Tuolumne County Citizens for Responsible Growth, Inc. v. City of Sonora* (2007) 155 Cal.App.4th 1214, 1226-27) (hereinafter *Tuolumne County*).) The CEQA "project" at issue here—the Refinery Project—is the set of integrated suite of regulatory actions taken by the District to achieve the Resolution's objective. Each of these rules represents a step towards achieving the Resolution's focused and targeted objective: a 20% reduction in refinery emissions.

Agencies are prohibited from "chopping up" projects into smaller components to minimize impacts or evade review. (*Laurel Heights Improvement Assn. v. Regents of Univ. of Cal.* (1988) 47 Cal.3d 376, 396; Cal. Code Regs. tit. 14, § 15378(a).) The moment it adopted Rules 12-15 and 9-14 with individual negative declarations, the District segmented those rules *from each other* and from its broader Refinery Project. The District's improper segmentation of the Refinery Project violates CEQA

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[1] CEQA is codified in sections 21000–21189 of the Public Resources Code. CEQA is implemented through the "Guidelines for Implementation of the California Environmental Quality Act," which are contained in California Code of Regulations, Title 14, Chapter 3, hereinafter referred to simply as the "CEQA Guidelines."

and subverts its core purpose of assuring a comprehensive assessment of "the whole of the action."

The District also failed to comply with important requirements of the California Health & Safety Code ("H&S Code") when adopting Rule 12-15, including the District's obligation to make findings of necessity, consistency, and non-duplication under H&S Code § 40727. The District must satisfy these requirements with "substantial evidence" that a "reasonable trier of fact could conclude. . . is reasonable, credible, and of solid value." (See *Plastic Pipe and Fittings Assn. v. Cal. Bldg. Standards Com* (2004) 124 Cal.App.4th 1390, 1406-07 (citations omitted).) Rather than proceed in a reasoned manner, the District based Rule 12-15 on unsubstantiated assumptions about what the rule *might* achieve, while arbitrarily ignoring inconvenient data and real-world facts.

Finally, the District lacks authority to adopt core provisions of Rule 12-15. It is black-letter law that "administrative agencies have only the powers conferred on them" and "may not act in excess of those powers." (*Am. Fed'n of Labor v. Unemployment Ins. Appeals Bd.* (1996) 13 Cal.4th 1017, 1042, n.9, citing *Ferdig v. State Personnel Bd.* (1969) 71 Cal.2d 96, 103-04). The District violated this principle when it adopted Rule 12-15 without authority for provisions related to refinery "crude slate" reporting and cargo carrier emissions. In doing so, the District ignored state and federal laws that preempt these provisions of Rule 12-15, and which render Rule 12-15 *ultra vires* and void.

Petitioners are the Western States Petroleum Association ("WSPA") and three individual refineries that will be significantly affected by Rules 12-15 and 9-14. Petitioners seek a writ of mandate from this Court ordering the District to (i) vacate and set aside the Initial Study/Negative Declarations for Rules 12-15 and 9-14; (ii) comply with CEQA and H&S Code requirements in any future Refinery Project rulemaking; and (iii) vacate and set aside Rule 12-15.

II. REGULATORY HISTORY & STATEMENT OF FACTS

In 2014, District staff recommended "approval of a resolution directing staff to develop a strategy to track and reduce emissions from Bay Area refineries." (AR Doc. 166 at, 004135; see also AR Doc. 168.) In late 2014, the District's Board expanded and codified this recommendation in the form of Resolution 2014-07,[2] which directed District staff to develop an integrated strategy to track refinery emissions and to reduce refinery emissions by 20%, "or as much [] as are feasible." (AR Doc. 194, at 004394-95.)

Following issuance of the Board's Resolution, the District initiated significant planning and scoping efforts to evaluate how to implement the Resolution's directives. The District labeled this integrated effort its "Refinery Emission Reduction Strategy" (the "Refinery Strategy" or "Strategy"). (See generally AR Doc. 90.) The District's strategy incorporated four components: (1) reducing criteria pollutants and precursors; (2) reducing health risks from air toxics; (3) tracking greenhouse gas ("GHG") emissions; and (4) improving control technology and practices. (AR Doc. 161, at 004069-70.) The District planned to implement these components through a "suite" of coordinated rulemaking actions in 2015 and 2016. (*Id.*; see also AR Doc. 147, at 003909.) As the first step, the District planned to develop and adopt a single package of rules to address criteria pollutants (including sulfur dioxide ("SO_2"), particulate matter ("PM"), and PM precursors) and tighten requirements for equipment leaks. (AR Doc. 163, at 004096-97.) The District also planned a second package of rules to address the Refinery Strategy's second objective, reducing risk from air toxics. (AR Doc. 163, at 004098.) Two months after the Board passed Resolution 2014-07, it approved the Refinery Strategy as the District's mechanism for achieving the Resolution's objective of a 20% reduction in refinery emissions. (AR Doc. 162, at 004075-80.)

In January, 2015, at the District's "Refinery Emissions Reduction Strategy Kick-Off Meeting," the District identified 13 refinery-focused rules, including Rule 9-14 and Rule 12-15, as components of its Refinery Strategy. (AR Doc. 694, at 011577-78.) The District targeted seven of those rules for adoption by late 2015 and indicated that these seven rules may collectively require an Environmental Impact Report ("EIR") under CEQA. (AR Doc. 694-A.)

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[2] At times, documents in the Administrative Record refer to Resolution 2014-07 as Resolution 2014-17. (*See*, *e.g.*, AR Doc. 47, employing both terms.) Petitioners believe this is a typographical error, and that the correct designation is Resolution 2014-07. For consistency and clarity, this brief will refer to "Resolution 2014-07" or simply the "Resolution."

In October 2015, the District proposed an initial package of six rules for adoption under the umbrella of the Refinery Strategy: Rules 8-18, 11-10, 6-5, 9-14, 12-15, and 12-16. (AR Doc. 53 (public hearing notice for Rules 8-18, 11-10, 6-5, and 9-14); AR Doc. 97 (public hearing notice for Rules 12-15 and 12-16).) The District prepared a single EIR for Rules 12-15 and Rule 12-16, but did not prepare an EIR for the other four rules. (AR Doc. 99.) The basis for this decision is unclear. The District first characterized Rules 8-18, 11-10, 6-5, and 9-14 as a separate individual CEQA "project" and prepared a single draft Negative Declaration covering all four rules. (AR Doc. 56, at 002194 (acknowledging that all four rules are "part of a concerted effort to reduce refinery emissions"); AR Doc. 57.) At the same time, this Negative Declaration evaluated each rule *separately* as an "individual action," based on the District's assertion that there were no "dependencies" between the four rules that comprised this "project." (AR Doc. 56, at 002194; AR Doc. 53, at 002190.)

In November 2015, Petitioners provided several hundred pages of substantive and technical comments on the six proposed rules, including Rules 9-14 and 12-15. These comments identified technical inaccuracies, legal issues, and the common objective of each rule as interrelated components of the Refinery Project. (AR Docs. 76-81; AR Doc. 146, at 003901-05.)

By the December 8, 2015 public hearing on these rules, the District changed course yet again, chopping up these six rules into multiple rulemaking actions. At the public hearing, the District announced that it would consider adoption of only three of the six originally-proposed rules: Rules 6-5, 8-18, and 11-10 (hereinafter referred to as the "Phase 1 Rules"). (AR Doc. 47, at 001819-20.) The remaining rules were delayed until 2016, although the District reiterated its intent to proceed with them, as they remained "important to meeting the Air District goals set forth in Resolution 2014-[0]7." (AR Doc. 47, at 001906.) The District subsequently adopted the Phase I Rules and approved the accompanying Initial Study/Negative Declaration. (AR Docs. 49 - 51; AR Doc. 68 (single negative declaration for Phase 1 Rules).) On January 22, 2016, three of the Petitioners in this case (Valero, Tesoro, and Phillips 66) filed a Petition and Complaint alleging that the District violated CEQA, failed to comply with the H&S Code, and acted in an arbitrary and capricious manner when it adopted the Phase 1 Rules. (See generally Case No. N16-0095; see also Case No. N16-0095, Amended Petition for Writ of Mandate, at 14:16-31:13.)

Less than two months after adopting the Phase 1 Rules, the District re-proposed Rules 9-14 and 12-15 (hereinafter referred to as the "Phase 2 Rules"). This time, instead of preparing an EIR for Rule 12-15, the District prepared individual Negative Declarations for both of the Phase 2 Rules. (AR Doc 15 (negative declaration for Rule 9-14); AR Doc 16 (negative declaration for Rule 12-15).) Despite significant changes to the rules and accompanying CEQA analyses, the District allowed only three weeks for submission of public comments on the re-proposed forms of Rules 9-14 and 12-15. Petitioners timely submitted detailed comments on the Phase 2 Rules that also addressed the broader Refinery Project and the District's lack of compliance with CEQA. (See AR Docs. 18-21.)

On March 21, 2016, the District posted further revisions to Rule 12-15, along with a 3-page document summarizing the changes made by the District, and on April 8, 2016, Petitioners submitted comments on this newly revised version of Rule 12-15. (See AR Docs. 23-25A.) On April 20, 2016, the District conducted a public hearing on Rules 9-14 and 12-15. (See AR Doc. 1 (transcript of hearing).) During the April 20 hearing, WSPA and the other Petitioners publicly commented on the Refinery Project, proposed Rule 12-15, and related issues. (*Id.*) At the end of the April 20 hearing, the District adopted both Phase 2 Rules and approved the accompanying IS/NDs. (AR Doc. 4 (Rule 12-15); AR Doc. 5 (adopting Rule 9-14).) On May 25, 2016, Petitioners timely filed this action, challenging the District's adoption of the Phase 2 Rules on multiple grounds.

III. STANDARD OF REVIEW

A. This Court Must Void Agency Decisions that Do Not Comply with CEQA.

CEQA requires all public agencies to conduct an environmental review of any "project" they carry out. (Pub. Res. Code § 21080.) A "project" is an "activity which may cause either a direct physical change in the environment, or a reasonably foreseeable indirect physical change in the environment." (Pub. Res. Code, § 21065.) CEQA "projects" include an agency's adoption of a rule or regulation, including those aimed at environmental protection. (*Cal. Unions for Reliable Energy v. Mojave Desert Air Quality Mgmt. Dist.* (2009) 178 Cal.App.4th 1225, 1240 (citations omitted).)

A series of actions undertaken to attain the same objective constitutes a single project. (*Tuolumne County,* 155 Cal.App.4th at 1226-27.) When reviewing a project under CEQA, the lead agency must consider the "whole of an action" and CEQA forbids an agency from "chopping a large project into many little ones" to evade a full environmental review. (*Laurel Heights Improvement Assn.*, 47 Cal.3d 376, 396 (quoting *Bozung v. LAFCO* (1975) 13 Cal.3d 263, 283-84); Cal. Code Regs. tit. 14 § 15378(a).)

The scope of a CEQA "project" is a question of law for the Court to decide. (*Tuolumne County*, 155 Cal.App.4th at 1224 ("The scope of a CEQA 'project' is a question of law to be reviewed de novo."); *Nelson v. County of Kern* (2010) 190 Cal.App.4th 252, 271.) Upon finding that an agency has violated CEQA, a court may issue a writ of mandate voiding an action and requiring compliance with CEQA. (Pub. Res. Code § 21168.9(a).) "Directing an agency to void its approval of the project is a typical remedy [] for a CEQA violation." (*POET, LLC v. Cal. Air Res. Bd.* (2013) 218 Cal.App.4th 681, 759) (citation omitted).)

B. This Court Must Set Aside Rules That Fail to Comply With the H&S Code or Are Arbitrary, Capricious, or Lacking in Evidentiary Support.

The H&S Code imposes several substantive requirements on the District when it engages in rulemaking. Among other things, the District "shall" make findings and assure that rules meet the following criteria: "necessity, authority, clarity, consistency, nonduplication, and reference." (H&S Code § 40727.) The District also "shall consider . . . the cost effectiveness of a control measure." (*Id.* § 40703.) These are mandatory requirements that the District must comply with when adopting any regulation. (*Id.* § 16 (H&S Code use of the word "shall" imposes a "mandatory" obligation).) The District must satisfy each of these requirements with "substantial evidence in the administrative record." (*Plastic Pipe and Fittings Assn.,* 124 Cal.App.4th at 1406 (citations omitted).) Substantial evidence exists only when a "reasonable trier of fact could conclude that the evidence is reasonable, credible, and of solid value." (*Id.*, at 1407 (citation omitted).)

The District's decisions also must be fair and reasoned. If the District's actions are "arbitrary, capricious, entirely lacking in evidentiary support, unlawful, or procedurally unfair," this Court must set them aside. (*Am. Coatings Assn. v. S. Coast Air Quality Dist.* (2012) 54 Cal.4th 446, 460.) When evaluating "whether a regulation is arbitrary, capricious, or lacking in evidentiary support, the court must ensure that an agency has 'adequately considered all relevant factors, and has demonstrated a rational connection between those factors, the choice made, and the purposes of the enabling statute.'" (*Id.* (quotation and citation omitted).)

C. Agency Action Not Authorized by the Legislature is Void.

There are two fundamental limitations on agency action. First, administrative agencies have only the powers granted to them by the Legislature, and "may not act in excess of those powers." (*Am. Fed'n of Labor,* (1996) 13 Cal.4th 1017, 1042, n.9, citing *Ferdig,* (1969) 71 Cal.2d 96, 103-04.) Second, agency action is void if preempted by an act of the Legislature. (*County of San Diego v. Bowen* (2008) 166 Cal.App.4th 501, citing and quoting *Agricultural Labor Relations Bd. v. Super. Ct. Court* (1976) 16 Cal.3d 392, 419; *Tolman v. Underhill* (1952) 39 Cal.2d 708, 712.) Agency actions are preempted when they duplicate, contradict, or infringe upon an area already fully occupied by another statute, either expressly or by legislative implication. (*Sherwin-Williams Co. v. City of Los Angeles* (1993) 4 Cal.4th 893, 897 (citations and quotations omitted).) Agency actions that exceed an agency's authority are void, and courts may issue a writ of mandate to "nullify the void acts." (*Am Fed'n of Labor*, 13 Cal.4th at 1042 (citation omitted).)

IV. ARGUMENT

A. The District Violated CEQA by Illegally Segmenting the Refinery Project.

In late 2014, the District adopted Resolution 2014-07, which established the defined goals of tracking refinery emissions (in part through Rule 12-15) and reducing those emissions by 20%. (AR Doc. 194, at 004394-95.) To achieve these objectives, the District first conceived its overarching Refinery Strategy. Next, working under the umbrella of the Refinery Strategy, the District developed a coordinated set of regulatory actions, to be adopted in several phases, that *together* would achieve the Resolution's defined objectives. (AR Doc. 161, at 004066-70 (describing approach and specifically discussing Rule 12-15); AR Doc. 147, at 003909-12 (identifying "phases" of Refinery Project).) These rules—including the Phase 1 Rules and the Phase 2 Rules—constitute the District's Refinery Project and, as the District acknowledged, each rule adopted as part of its Refinery Project is "part of a concerted effort to reduce refinery emissions." (AR Doc. 56, at 002194.)

The District first violated CEQA when it adopted the Phase 1 Rules without any form of unified CEQA review, effectively segmenting those three rules from each other and from the District's broader Refinery Project. The District repeated this failure when it adopted the Phase 2 Rules challenged here (Rules 9-14 and 12-15), again segmenting these rules from each other and failing to consider the cumulative impacts of the Phase 2 Rules and other Refinery Project actions, including the previously-adopted Phase 1 Rules. This approach enabled the District to artificially minimize the total environmental impact of the Refinery Project as a whole, which in turn allowed the District to avoid preparing an EIR assessing *all* environmental impacts of the Refinery Project. These actions violate CEQA and frustrate its core purposes of informing the public as to the true scope of a project and assuring a comprehensive review of "the whole of the action."

1. There is a Single CEQA Project At Issue—the Refinery Project—Which Encompasses Each Regulatory Step The District Takes to Achieve the Resolution's 20% Refinery Emissions Reduction Objective.

Collectively, the suite of rules adopted by the District to achieve the common, well-defined objectives of the Resolution constitute a single CEQA project—the Refinery Project. (*Tuolumne County*, 155 Cal.App.4th at 1226-27 (all of the "various steps which taken together obtain an objective" comprise a single CEQA project).) CEQA defines a "project" as "an activity which may cause either a direct physical change in the environment, or a reasonably foreseeable indirect physical change in the environment, and which is . . . [a]n activity directly undertaken by any public agency." (Pub. Res. Code § 21065.) The District's approval of multiple refinery regulations to achieve a common objective is "an activity" that, by design, will cause a physical change in the environment and is subject to CEQA. (See *id.*)

It is abundantly clear that there is a CEQA "project" at issue. The only remaining question is to determine the proper *scope* of that project. (*Nelson*, 190 Cal.App.4th 252, 267 ("a correct determination of the nature and scope of the project is a critical step in complying with the mandates of CEQA") (citations and quotations omitted).) The key inquiry thus becomes: is the scope of the District's CEQA project limited to each individual rule, or does it include—in the District's own words—the entire "suite" of regulations adopted by the District to achieve the unified goals of the Board's Resolution?

The correct answer is the latter. The District itself admits that both the Phase 1 Rules and the Phase 2 Rules challenged here were adopted as part of a concerted effort by the District to achieve the Resolution's objective of reducing refinery emissions by 20%. (Compl. at 4:24-27, Answer at 3:21 (District admitting that it "adopted [] Rules 12-15 and 9-14 as part of its Refinery Strategy"); see also AR Doc. 56, at 002194.) The District also admits that its approval of Rules 12-15 and 9-14 is subject to CEQA. (Compl. 17:13-16; Answer 8:26.) And the District further admits that its previously-adopted Phase 1 Rules "have been characterized by the Air District as implementing different phases of the Refinery Strategy." (Answer at 6:5-7.) In short, the District admits that all five of these rules are steps towards achieving the concrete emissions reduction objective of Resolution 2014-07, and that these steps are subject to CEQA.[3]

The Record in this case further supports the conclusion that there is a single CEQA project at issue. From the moment the Board issued Resolution 2014-07 in late 2014, the District began to develop a unified approach and holistic plan to achieve the Resolution's goals. Within two months, the District had developed a multi-phased "Refinery Emission Reduction Strategy," which it intended to implement over the following two years. (AR Doc. 161, at 004069-70.) Within three months, the District held a "Refinery Emissions Reduction Strategy Kick Off Meeting" to discuss its "rule development efforts" and a unified approach to developing up to twenty individual rules as components of the Refinery Project—including the Phase 1 Rules, the Phase 2 Rules, and others. (AR Doc. 694, at 011575-83.) To manage this significant and coordinated undertaking, the District created a project workflow chart assigning roles and responsibilities to twenty-two District staff members tasked with handling specific aspects of the District's Refinery Project rulemaking effort. (*Id.* at 011583.)

While the timing and details of the Refinery Project changed over the following months, this holistic approach—the District's plan to develop a number of interrelated rules, in multiple phases, to collectively achieve the objectives set forth by the Resolution—did not. In March 2015, the District reported that its staff had "developed a Refinery Emission Reduction Strategy in response to Resolution

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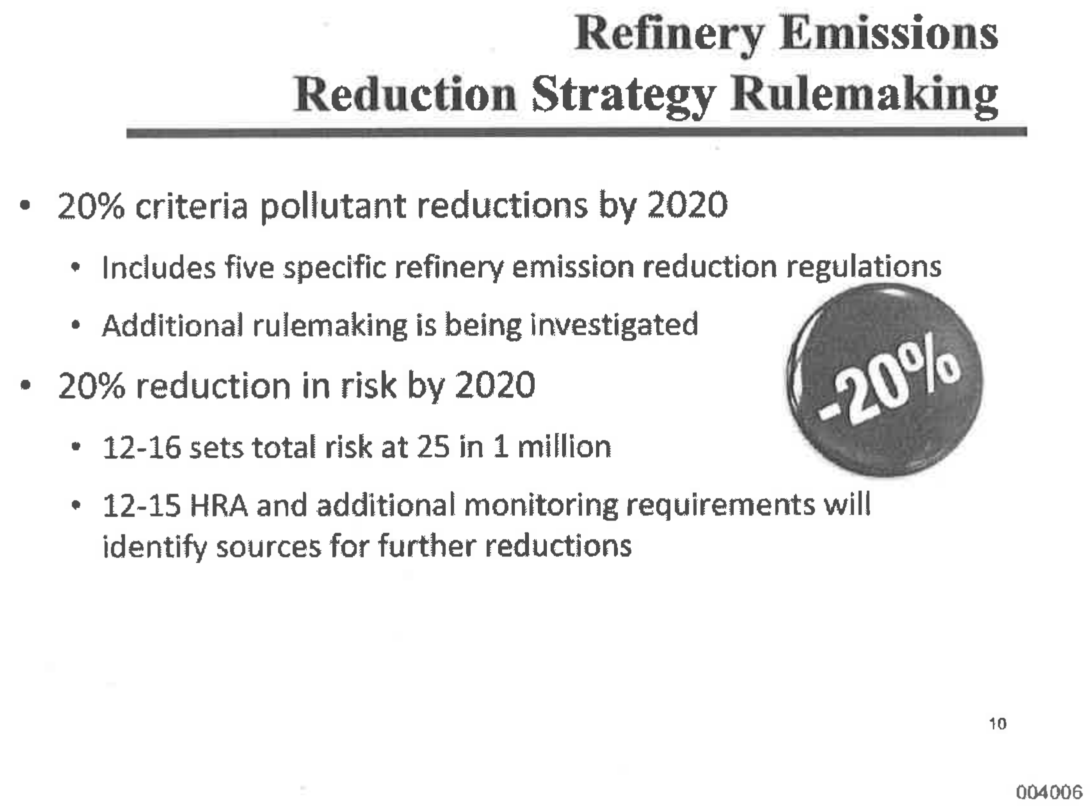
[3] In litigation challenging the Phase 1 Rules, the District admitted that its approval of those rules is subject to CEQA and that each of the Phase 1 Rules was "intended to help achieve the 20% emissions reduction goal" set forth in Resolution 2014-07. (Case No. N16-0095, Answer at 7:7-9; 10:22-24.)

2014-[0]7, ***identifying specific rulemaking to meet the goal of reducing refinery emissions by 20%***," and which included "a five-point action plan to provide a path forward to quickly and effectively address [refinery emissions]." (AR Doc. 156, at 004028 (specifically linking Rule 12-15 and other rules to the 20% emissions reduction goal) (emphasis added).) In June 2015, the District presented that plan—again specifically linking each set of regulatory actions to the Project's objective of achieving a 20% reduction in refinery emissions and health risks. (See generally AR Doc. 155.) The District's presentation explains this link quite clearly:



Refinery Emissions Reduction Strategy Rulemaking

- 20% criteria pollutant reductions by 2020
  - Includes five specific refinery emission reduction regulations
  - Additional rulemaking is being investigated
- 20% reduction in risk by 2020
  - 12-16 sets total risk at 25 in 1 million
  - 12-15 HRA and additional monitoring requirements will identify sources for further reductions

(AR Doc. 155, at 004006).

The District continued to treat these rules as related parts of a single effort, both internally and in presentations to the public. Shortly before adopting the Phase 1 Rules, the District again explained its Refinery Project using a straightforward chart:

BAY AREA AIR QUALITY MANAGEMENT DISTRICT

REFINERY STRATEGY

REDUCE HARMFUL EMISSIONS → CONTINUOUS MONITORING → LIMIT POLLUTION & PROTECT HEALTH → ENSURE BEST PRACTICES

Reduce Harmful Emissions: The Air District staff is developing a suite of regulations to reduce emissions of criteria pollutants from Bay Area refineries by 20 percent (or as much as feasible) by 2020. The first phase of these regulations will be considered by the Board in December 2015 and will:

- Reduce sulfur dioxide (SO_2) from coke-calcining
- Reduce organic compound and toxic emissions from equipment leaks and cooling towers
- Limit ammonia emissions from fluid catalytic cracking (FCC) units, which will reduce associated formation and emission of fine particulate matter ($PM_{2.5}$)

In mid-2016, the second phase of the strategy will further reduce:

- SO_2 from FCC units and other refinery sources
- $PM_{2.5}$ emissions from FCC units
- Nitrogen oxide (NO_x) emissions from turbines

Continuous Monitoring: Draft Regulation 12, Rule 15, Petroleum Refining Emissions Tracking, will require:

- Continuously updated, state-of-the-art methods be used to calculate and report the total pollution from the refineries every year
- Extensive air quality monitoring to validate those pollution calculations and ensure surrounding communities are not subjected to unhealthy levels of pollution
- Requirements that will use emission inventories and monitoring data to identify potential reductions
- An energy audit identifying potential improvements to reduce GHGs
- New, more protective, Health Risk Assessments be performed to determine the health risk from toxic air pollutants

Limit Pollution & Protect Health: Draft Regulation 12, Rule 16, Petroleum Refining Emissions Limits and Risk Thresholds, will:

- Limit refinery criteria pollutant and toxic emissions to levels that minimize the health burden for the surrounding communities
- Require Health Risk Assessments have updated information every year as new emissions data are received

Ensure Best Practices: Air District staff is developing changes to the Air District permitting regulations to ensure that when refineries modernize or make significant changes to the type of crude oil they use, they will be required to use the best available control technology to reduce smog-forming, toxic, and climate pollutants. Over time, these changes to the permitting regulations will ensure the refineries use best practices and operate as efficiently and cleanly as possible.

REFINERY STRATEGY

BAY AREA AIR QUALITY MANAGEMENT DISTRICT

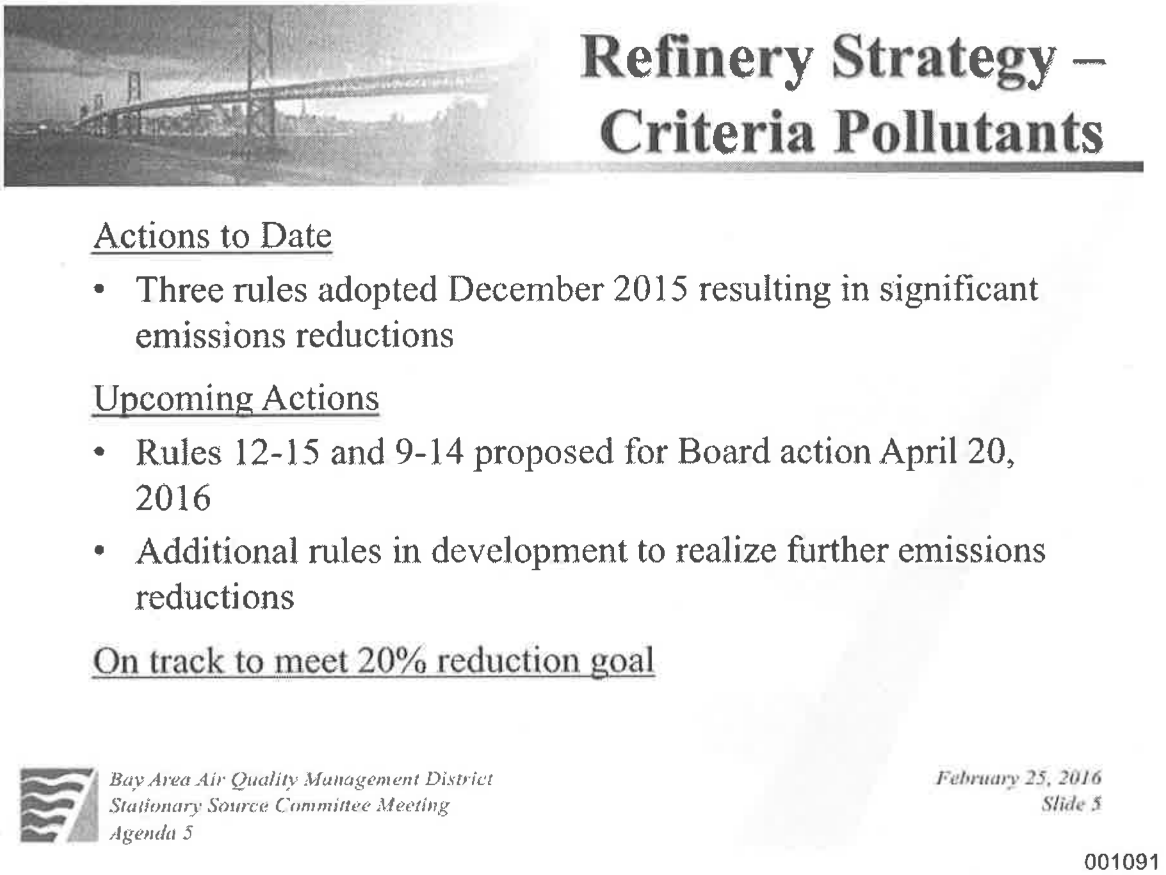
3

003909

(AR Doc. 147, at 003909.)

This chart bears a striking resemblance to the District's initial description of its Refinery Strategy: multiple components, each relying on several regulatory steps that build upon each other to achieve the District's unified emissions reduction objective.

In early 2016, just before adopting the Phase 2 Rules, the District again affirmed the interrelated nature of each Refinery Project rulemaking phase. (AR Doc. 28, at 001069 (describing how District staff "discussed the refinery strategy" which it then contemplated as encompassing at least ten rules adopted in four phases).) A few weeks later, on February 25, 2016, the District gave a presentation noting that the combination of the Phase 1 Rules it had previously adopted and the Phase 2 Rules it had (at that time) recently proposed put the District "on track to meet the 20% reduction goal." (AR Doc. 30 at 001091.)



Refinery Strategy – Criteria Pollutants

Actions to Date

- Three rules adopted December 2015 resulting in significant emissions reductions

Upcoming Actions

- Rules 12-15 and 9-14 proposed for Board action April 20, 2016
- Additional rules in development to realize further emissions reductions

On track to meet 20% reduction goal

Bay Area Air Quality Management District
Stationary Source Committee Meeting
Agenda 5

February 25, 2016
Slide 5

001091

(AR Doc. 30 at 001091.)

As the District's actions and documents demonstrate, each of the Refinery Project's rules, including the Phase 2 Rules challenged here, are aimed squarely at achieving the specific objective described in the Resolution: reduce refinery emissions and health risks by 20%, or as much as feasible. (AR Doc. 147, at 003909.) The District intended its suite of rules—the entire Refinery Project—to work *together* to achieve this common goal. (*Id.*; see also AR Doc. 147, at 003911; AR Doc. 30 at 001090-91.) As the District's Staff Report for Rule 9-14 makes clear:

> [The District] has developed a four-part strategy for addressing air pollution from Bay Area petroleum refineries (known as the Refinery Strategy). This strategy stems from a resolution (2014-17) the Air District Board of Directors adopted in October 2014, instructing staff to develop a regulatory strategy that would further reduce emissions from petroleum refineries, with a goal of an overall reduction of 20 percent (or as much as feasible) no later than 2020.

(AR Doc. 2, at 000561.) The District went on to note that its Phase 1 Rules are "expected to reduce overall emissions from petroleum refineries by approximately 14 percent" while Rule 9-14 is expected to "reduce overall refinery emissions by an additional 1 percent." (*Id.*) And the District has repeatedly emphasized the role of Rule 12-15 as a component of its Refinery Project that is key to achieving the goals of Resolution 2014-07. (See, e.g., AR Doc. 30 at 001090, AR Doc. 147, at 003909.)

Given the interdependence of the District's regulatory actions and their common underlying purpose, it is plain that they are "various steps which taken together obtain an objective" and comprise a single "project" for purposes of CEQA—the Refinery Project. (*Tuolumne County*, 155 Cal.App.4th at 1226-27.)

2. The District Violated CEQA By Chopping Up the Refinery Project and Failing to Conduct a Unified Review of All Refinery Project Actions.

The District understood the integrated nature of its Refinery Project rulemaking efforts but took a cavalier approach to its CEQA obligations. The fact that a specific project may occur through multiple components or phases does not excuse an agency from CEQA's mandate to evaluate "the whole of the action." (*Cal. Union for Reliable Energy*, 178 Cal.App.4th at 1242) (citing 1 Kostka Zischke, Prac. Under the Cal. Envt'l Quality Act, § 6.31, 329-330).) "This prevents agencies from chopping a large project into little ones, each with a minimal impact on the environment, to avoid full environmental disclosure. . . . Piecemeal environmental review that ignores the environmental impacts of the end result is not permitted." (*Id.*) But this is exactly what the District did here.

The District did not prepare an EIR for the Phase 1 Rules, the Phase 2 Rules, or the Refinery Project as a whole. Instead, the District reviewed each of its five adopted rules in isolation from the others, concluded that each rule had no significant environmental impact, and adopted negative declarations in each instance. (See AR Doc. 68 (single negative declaration for Phase 1 Rules); AR Doc 15 (negative declaration for Rule 9-14); AR Doc 16 (negative declaration for Rule 12-15).)

At the same time, District staff had previously recognized that "it would be good to consider the cumulative impacts of the whole suite of regulatory efforts" under CEQA. (AR Doc. 831, at 012657.)

This apparent disconnect appears to derive from the District's shifting views of its CEQA obligations, with the District reformulating its approach on at least three different occasions (so far):

- October, 2015: the District proposes its Phase 1 Rules, along with Rules 9-14, 12-15, and 12-16, concluding that (i) Rules 12-15 and 12-16 are a single "project" requiring an EIR and (ii) the remaining four rules are a separate individual CEQA "project." (AR Doc. 98; AR Doc. 56, at 002194.)
- December, 2015: the District severs the three Phase 1 Rules and adopts them with a single Negative Declaration, treating each of the three rules as separate CEQA "projects." (AR Doc. 68; see also AR Doc. 47, at 002003.)
- April, 2016: the District adopts Rules 9-14 and 12-15 as a single "project," ignoring both its prior EIR for Rule 12-15 and prior grouping of Rule 9-14 with the Phase 1 Rules and concluding instead that each of these two rules requires only a stand-alone Negative Declaration. (AR Docs. 15, 16 (negative declarations for Rules 9-14 and 12-15).)

At each stage, the District redefined its CEQA obligations based on expediency, resulting in an artificial compartmentalization of various Refinery Project rules and CEQA reviews structured for—in the District's own words—"administrative convenience." (AR Doc. 68, at 002312.) But CEQA requirements are driven by substance, not logistics.

When a set of actions is aimed at a common objective—such as tracking and reducing refinery emissions by 20%—CEQA requires the agency to evaluate those actions *together*:

> One way to evaluate which acts are part of a project is to examine how closely related the acts are to the overall objective of the project. The relationship between the particular act and the remainder of the project is sufficiently close when the proposed physical act is among the various steps which taken together obtain an objective.

(*Tuolumne County*, 155 Cal.App.4th at 1226-27 (citation and quotation omitted).)

Given CEQA's core "purpose of informing the public about *potential* environmental consequences, it is quite clear that an EIR is required even if the project's ultimate effect on the environment is far from certain." (*Cal. Bldg. Indus. Assn. v. Bay Area Air Quality Mgmt. Dist.* (2015) 62 Cal.4th 369, 382 (emphasis original).) This requirement is designed to assure that *all* of a project's impacts are considered at the same time, since a set of smaller actions may result in a significant cumulative effect on the environment. (*Laurel Heights Improvement Assn.*, 47 Cal.3d at 396.)

Because the Phase 1 and Phase 2 Rules—and numerous other rules still under development—were collectively designed to achieve a defined, targeted objective (*i.e.*, the goals of Resolution 2014-07) they are part of a single CEQA project. (*Tuolumne County*, 155 Cal.App.4th at 1226-27.) By analyzing the Phase 2 Rules in isolation from each other and from the other Refinery Project rules, the District addressed only a fraction of the entire Refinery Project. That action subverts CEQA's fundamental purpose of assuring a comprehensive environmental review of "the whole of an action." (Cal. Code Regs. tit. 14 § 15378(a); *Bozung*, 13 Cal.3d at 283-84; *Nelson*, 190 Cal.App.4th at 271.)

3. The District Failed to Justify Its Illegal Segmentation of the Refinery Project.

Given the clear relationship of the District's Refinery Project rules and the integrated regulatory process undertaken by the District, Petitioners repeatedly asked the District to conduct a comprehensive CEQA analysis that incorporated *all* Refinery Project actions. (See AR Doc 18 at 000856; AR Doc. 20 at 000918-19; AR Doc. 23 at 000943.) In response, the District asserted that its Refinery Project rules are simply business-as-usual rulemaking. (AR Doc. 7, 000749-52.) That argument is a strawman and grossly oversimplifies the scope and unified nature of the Refinery Project. This is not "business-as-usual" rulemaking: the Refinery Project envisions ten to twenty individual rules, all aimed at the unified, common objectives of Resolution 2014-07. (See AR Doc. 694, at 011575-83 (discussing a unified approach to developing up to twenty individual rules under the Refinery Project); see also AR Doc. 28, at 001069 (describing ten rules the District has either already adopted or considered for adoption in the near future as components of the Refinery Project).)

Projects often occur in multiple phases or components, but that does not excuse an agency from CEQA's mandate to evaluate "the whole of the action." (*Cal. Union for Reliable Energ,* 178 Cal.App.4th 1225, 1242.) Taken to its logical conclusion, the District's approach to the Refinery Project would permit it to segment any regulatory effort into many smaller regulations, minimize the perceived impacts by reviewing each component in isolation, and avoid a cohesive review of the entire project. This is exactly what CEQA prohibits. (See *Laurel Heights Improvement Assn.,* 47 Cal.3d at 396; see also *Banning Ranch Conservancy v. City of Newport Beach* (2012) 211 Cal.App.4th 1209 at 1223 (citing numerous examples of improper segmentation).)

The District further claimed that while the Refinery Project may represent a "quantitative difference" from the District's past rulemaking practices, there is no "qualitative difference" because of the theoretical "independent utility" of each rule. (AR Doc. 7, at 000749-52.)[4] The District is wrong. Determining the scope of a CEQA project depends on evaluating how closely related different "acts are to the overall objective of the project." (*Tuolumne County*, 155 Cal.App.4th at 1226.) Multiple regulatory actions constitute a single project when they are "various steps which taken together obtain an objective." (*Id.* (citation and quotation omitted).) And, crucially: "[t]heoretical independence is not a good reason for segmenting the environmental analysis of the two matters." (*Id.* at 1230.) No amount of "theoretical independence" can alter the basic fact that the Phase 2 Rules—along with the Phase 1 Rules and the rest of the District's "suite of regulations"—were conceived and adopted to achieve a single, common objective: tracking and reducing refinery emissions by 20%.

As the Record in this case amply demonstrates, there is one CEQA project at issue here—the Refinery Project—which necessarily encompasses the entire "suite" of regulatory actions taken by the District to achieve the objectives of Resolution 2014-07.[5] (See *Tuolumne County*, 155 Cal.App.4th at 1224). The District violated CEQA by chopping up the Refinery Project into multiple pieces and analyzing each of those pieces in isolation, an action that undermines CEQA's dual purpose of informing the public and assuring review of "the whole of the action."

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[4] The District simultaneously admits that two Refinery Project Rules—Rules 12-15 and 12-16—"arguably did have a functional interdependence" but that the District fixed that problem by removing "links to Rule 12-16" from Rule 12-15 and by "re-examin[ing]" Rule 12-16. The District does not explain exactly what "links" it removed, or precisely why the two rules no longer have "functional interdependence." (AR Doc. 7, at 000751.)

[5] At times, the District has attempted to frame Petitioners' concerns as related to Resolution 2014-07 and the District's corresponding planning process to design a set of actions to achieve the Resolution's goals. (See AR Doc. 7 at 000749-52.) Petitioners do not take issue with the District's internal planning process, and do not allege that the Resolution itself constitutes a CEQA "project." But once the District actually adopted specific regulations resulting from that process (regulations that each work together to achieve a unified, concrete and focused objective), the District's inchoate "Refinery Strategy" became a CEQA "project"—the Refinery Project—triggering its CEQA obligations.

B. Rule 12-15 is Arbitrary, Capricious, and Fails to Comply With the H&S Code.

The District is required to demonstrate the "necessity" of each new or amended rule it adopts while also assuring that such rules do not duplicate or interfere with requirements already imposed under federal or state law. (H&S Code § 40727(b)(1),(4)-(5).) The District must base these determinations on substantial evidence in the record that is "reasonable, credible, and of solid value." (*Plastic Pipe and Fittings Assn.*, 124 Cal. App. 4th at 1407.) Here, the District failed to demonstrate a "rational connection" between the requirements imposed by Rule 12-15 and the District's purported justification for the rule, rendering Rule 12-15 arbitrary, capricious, and void. (*Am. Coatings Assn.*, 54 Cal.4th 446, 460 (citation omitted).)

Rule 12-15 is a new regulation that is intended to track air emissions from petroleum refineries and to characterize the properties of crude oil processed by the refineries. (Rule 12-15, § 12-15-101.) Rule 12-15 has three main requirements: (1) an annual emissions inventory; (2) a monthly crude slate report; and (3) operation of a fence-line monitoring system. The annual emissions inventory component requires petroleum refineries to submit a detailed accounting of the types and quantities of emissions of criteria pollutants, toxic air contaminants, and GHGs released from (i) all stationary source processes at the petroleum refinery, and (ii) cargo carriers during loading and unloading operations. (Rule 12-15, § 12-15-206; § 12-15-401.) Beginning in calendar year 2018, refineries also will need to report year-to-year variations in emissions. (Rule 12-15, § 12-15-401.4.) The monthly crude slate reporting component requires petroleum refineries to summarize the volume and properties[6] of the crude oil and non-crude oil feedstock blends processed at a refinery in each calendar month. (Rule 12-15, § 12-15-408.) Lastly, to "complement" the emissions inventory and monthly crude slate reporting requirements, petroleum refineries must prepare air monitoring plans and operate fenceline monitoring systems to measure air pollutant concentrations at refinery fencelines. (Rule 12-15, § 12-15-403; § 12-15-501.) At its core, Rule 12-15 is an expansive reporting rule—it does not reduce emissions from petroleum refineries or otherwise solve an identified emissions problem.

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[6] The properties to be reported are total volume processed, API gravity, sulfur content, vapor pressure, benzene, toluene, ethylbenzene, and xylenes ("BTEX") contents, and iron, nickel, and vanadium. (Rule 12-15, § 12-15-408, Table 1.)

The District attempted to justify the necessity of Rule 12-15 based on its hypothesis that the crude slate data collected by Rule 12-15 *might* relate to actual refinery emissions and therefore *might* help the District identify future emissions reductions. But the District has not demonstrated any link between monthly crude slate data and refinery emissions; nor has the District explained how data related to emissions from third-party cargo carriers (over which a refinery has no control) relates to emissions from refinery facilities themselves. The District is obligated by the H&S Code to demonstrate the necessity of each of its rules with "substantial evidence" and cannot adopt rules based on mere hypotheses. (See *Plastic Pipe and Fittings Assn.*, 124 Cal. App. 4th at 1407.) Rule 12-15 also contains numerous provisions that overlap, duplicate, and conflict with existing regulatory programs, contrary to the requirements of H&S Code § 40727. These failings render Rule 12-15 arbitrary, capricious, and void. (*Am. Coatings Assn.*, 54 Cal.4th 446, 460.)

1. The District Failed to Demonstrate the Necessity of Rule 12-15.

The District's primary justification for adopting Rule 12-15 is that—according to the District—Rule 12-15 is "necessary to ensure the maintenance of the NAAQS and ensure protection of the public from toxic air contaminants given the size and impact of the refineries and the possibility of changes to the properties of crude oil processed at these refineries." (AR Doc. 2, at 000301.) By its terms, however, Rule 12-15 is an emissions tracking rule. It does not require *any* reductions in emissions of criteria pollutants or toxic air contaminants.

Nor does the District claim that Rule 12-15 will itself affect refinery emissions in any manner. Rather, the District identifies the emissions inventory, monthly crude slate report, and fenceline monitoring requirements in Rule 12-15 as components of an "investigation" that the District would like to initiate regarding potential sources of emissions. This investigation will purportedly enable the District to "decide whether such changes should be addressed in future regulations" or, conversely, whether "resources should be focused elsewhere." (AR Doc. 2, at 000281.) In particular, the District asserts that if there is a "significant" relationship between the processing of heavier crude oil and higher emissions, then Rule 12-15 "will help alleviate an air quality problem" through additional rulemakings targeting the issue. (AR Doc. 7, at 000766.) But the record contains no support for the District's hypothesis that monthly crude slate data will shed any light on changes in refinery emissions, which vary (within the parameters of a facility's operating permit) on a continual basis and depend on numerous physical and operational factors. (See, e.g., AR Doc. 2, at 000281 (speculating, without proof, as to relationship between crude slate data and emissions).)

Throughout the rulemaking process, the District's explanation of the necessity of Rule 12-15 repeatedly changed, ranging from the possibility that, as unspecified new sources of crude oil become available, the changes might, at some unspecified future time, result in increased emissions; to hypothesizing that "refineries may not be properly attributing exceedances of emissions limits to changes in crude characteristics" such that refineries "may be proceeding with alterations, and possibly modifications, without the proper [New Source Review] permit"; before finally landing on the justification set forth in the final Staff Report. (See AR Doc. 7, at 000766-67 (discussing justifications for Rule 12-15).) This game of regulatory whack-a-mole demonstrates that Rule 12-15 is a solution in search of a problem.

Rule 12-15 is designed solely to research "ideas for changes" to the District's rules applicable to petroleum refineries. (AR Doc. 7, at 00767.) The District cannot justify the necessity of Rule 12-15 based on the mere *hunch* that a correlation exists between the rule's requirements (*i.e.* crude slate reporting) and the District's stated justification for Rule 12-15: reducing emissions of criteria and toxic air contaminants. (See AR Doc. 2, at 000301.) By basing its finding of necessity on little more than the District's own hypotheses, the District failed to demonstrate the "necessity" of Rule 12-15 with substantial evidence that is "reasonable, credible, and of solid value." (*Plastic Pipe and Fittings Assn.*, 124 Cal. App. 4th at 1407.)

2. The District Violated the H&S Code By Adopting Rule 12-15 Provisions That Duplicate And Conflict With Numerous Existing Laws.

Prior to adopting a new rule, the District must demonstrate that the requirements of that rule harmonize with and do not duplicate requirements already imposed under federal or state law. (H&S Code § 40727(b)(4)-(5).) A duplicative regulation is only authorized if it is necessary for the District to execute its powers and duties. (*Id.* § 40727(b)(4).) The emissions inventory requirement in Rule 12-15 duplicates a variety of emissions reporting obligations already required under existing federal and state law, while also requiring inconsistent emissions reporting and calculations methodologies.

The emissions inventory requirement in Section 12-15-401 covers criteria pollutants, toxic air contaminants, and GHGs. (Rule 12-15 §§ 12-15-401.2-3) Each of these three categories of air pollutants are already regulated under various federal, state, and District programs, and each of these programs already have emissions inventory requirements. (See AR Doc. 18, at 000867-68 (Petitioners' written comments identifying existing programs).) For example, the District already requires permitted facilities in the Bay Area to complete an annual "permit renewal questionnaire" which requires facilities to quantify their emissions of criteria pollutants, toxic air contaminants, and GHGs, among other information. (AR Doc. 7, at 000753.) Petroleum refineries also must submit an array of emissions information to regulatory agencies, which, together, would provide the District with the very information it seeks under Rule 12-15. (See AR Doc. 18, at 000867-68.) Refineries have developed tracking and reporting systems to implement these various existing programs, but Rule 12-15 imposes overlapping and at times conflicting reporting methodologies—adding a new layer of bureaucracy while generating no new benefits. (AR Doc. 18, at 000868.)

The record does not support the need for the duplicative and inconsistent requirements of Rule 12-15. As support for its nonduplication finding, the District provides only a conclusory assertion that "there is overlap with state and federal requirements but no duplication[,]" and that this overlap was justified because "the Air District's requirements are more specific . . . and are thus appropriate to carrying out the Air District's power and duties." (AR Doc. 7, at 000754; see also AR Doc. 2, at 000473-75 (District's Regulatory Analysis).) The District also failed to evaluate whether the other sources of emissions information cited by Petitioners may provide some or all of the information it requires, or whether Rule 12-15 could be streamlined to minimize duplicative or inconsistent reporting requirements; the record contains no "substantial evidence" that the District evaluated—much less addressed—Petitioners' concerns related to overlapping and conflicting requirements.

The District has the means to obtain the underlying emissions data for criteria pollutants, toxic air contaminants, and GHGs that it seeks through existing channels. Rule 12-15 imposes duplicative monitoring and reporting requirements on the Bay Area refineries. The District's cursory and conclusory evaluation of these issues fails to satisfy the District's obligation to make H&S Code findings based on "substantial evidence." (See *Plastic Pipe and Fittings Assn.*, 124 Cal. App. 4th at 1407; *Am. Coatings Assn.*, 54 Cal.4th 446, 460.)

C. The Legislature Did Not Authorize the District to Adopt Numerous Provisions of Rule 12-15 That Are Preempted by State and Federal Law.

The District has no statutory authority for two core provisions of Rule 12-15 that require refineries to submit to the District (i) "crude slate" information and (ii) emissions data from locomotives and marine vessels owned and operated by third parties (collectively "cargo carriers"). Not only does the District lack express statutory authority to impose these requirements, its actions are preempted by numerous state and federal statutes that entirely occupy these fields. (*Sherwin-Williams Co.*, 4 Cal.4th at 897 (agency action is void when it duplicates, contradicts, or infringes upon an area already fully occupied by another statute); see also *Am. Fed'n of Labor*, 13 Cal.4th 1017, 1042, n.9 (agencies "may not act in excess of [the] powers" granted to them by the Legislature).) Because Rule 12-15's core provisions exceed the District's authority and are preempted by numerous California and federal laws, Rule 12-15 is void. (*Am. Fed'n of Labor*, 13 Cal.4th at 1039.)

1. The District Has No Authority to Adopt Core Provisions of Rule 12-15.

Legislative authorization is a fundamental prerequisite to agency action and actions taken without a grant of Legislative authority are void. (*Am. Fed'n of Labor*, 13 Cal.4th at 1039.) To enforce this limitation on agency action, courts must "conduct independent review of whether [an agency has] exceeded the scope of authority delegated by the Legislature to [it]." (*S. Cal. Gas Co. v. S. Coast Air Quality Mgmt. Dist.*, (2011) 200 Cal.App.4th 251, 268 (citation omitted); see also *Yamaha Corp. of Am. v. State Bd. of Equalization* (1998) 19 Cal.4th 1, 11, n. 4 ("A court does not . . . defer to an agency's view when deciding whether a regulation lies within the scope of the authority delegated by the Legislature.") (citation and quotation omitted).)

California law requires the District to identify the basis for its "authority" to adopt any rule or regulation. (H&S Code 40727(a),(b)(2)). As its authority for Rule 12-15, the District points to H&S Code Sections 42303 ("Section 42303") and 41511 ("Section 41511"). (AR Doc. 7, at 000767 (asserting that the District's "information-gathering authority pursuant to Health & Safety Code

Sections 41511 and 42303 is broad enough to allow this type of investigatory inquiry").) Section 42303 provides that:

> An air pollution control officer, at any time, may require from an applicant for, or the holder of, any permit provided for by the regulations of the district board, such information, analyses, plans, or specifications which will disclose the nature, extent, quantity, or degree ***of air contaminants*** which are, or may be, ***discharged by the source*** for which the permit was issued or applied.

(H&S Code § 42303 (emphasis added).) And Section 41511 provides that:

> For the purpose of carrying out the duties imposed upon the state board or any district, the state board or the district, as the case may be, may adopt rules and regulations to require the owner or the operator of any air pollution emission source to take such action as the state board or the district may determine to be reasonable for the determination of the amount ***of such emission from such source***.

(H&S Code § 41511 (emphasis added).) Neither of these provisions grants the District any authority to adopt the crude slate and cargo carrier provisions of Rule 12-15.

Rule 12-15 is not a "typical" air quality rule measuring smokestack emissions or imposing emissions limits. Instead, Rule 12-15 is aimed at several aspects of refinery operations that the District believes *might* relate to air emissions (such as a refinery's "crude slate" and third-party operations that refineries have no control over (*i.e.*, cargo carriers). (See AR Doc. 2 at 000287-91.) The District's purported authority for Rule 12-15, however, is based on H&S Code provisions that expressly limit their scope to "*air contaminants*" and "*emissions*" from the "source" itself. (H&S Code §§ 42303, 41511 (emphasis added).) These provisions do not confer *any* express authority to collect crude slate data which has, in the District's own words—an "uncertain[]" relationship to "refinery air emissions." (AR Doc. 2 at 000291.) Nor do they confer any authority to require refineries to provide emissions data from cargo carriers, which are not part of the refinery "source," and which are owned and operated by unrelated third parties over whom the refineries have no control.

Under long-standing principles of statutory interpretation, "[t]he expression of some things in a statute necessarily means the exclusion of other things not expressed." (*Gikas v. Zolin*, (1993) 6 Cal.4th 841, 852.) By conferring authority to collect *emissions* data while remaining silent on other types of information the Legislature manifestly did *not* grant the District any authority to require reporting on operational matters, such as a refinery's crude slate. Similarly, by conferring authority to collect data from the "source" itself, the Legislature plainly did *not* grant the District the authority to compel refineries to report data from mobile sources such as cargo carriers that are *not* part of the refinery "source."[7]

2. Crude Slate Requirements Are Preempted by California's Petroleum Industry Information Reporting Act.

The crude slate reporting requirements of 12-15 are preempted by California's Petroleum Industry Information Reporting Act ("PIIRA"), which establishes a comprehensive system for reporting the very type of crude slate data that the District seeks here to the California Energy Commission ("CEC"). (Pub. Res. Code §§ 25350-25366; C.C.R. Title 20 §§ 1361-1371; see also *Sherwin-Williams Co.*, 4 Cal.4th at 897 (agency action preempted when it "enters an area fully occupied by general law").) The California Legislature enacted PIIRA in 1980 with the purpose of creating "a complete and thorough understanding of the operations of the petroleum industry." (Pub. Res. Code § 25350(b).) Among other things, PIIRA was established in order to collect "information and data concerning ***all aspects of the petroleum industry***." (Pub. Res. Code § 25350(c) (emphasis added).) Indeed, PIIRA applies to nearly all entities in California who engage in commerce related to petroleum products, and which are required by the statute to submit petroleum product and crude oil data to CEC on a periodic basis. (Pub. Res. Code § 25354.) As the Legislature made abundantly clear, this type of information was of paramount state concern because "the petroleum industry is an essential element of the California economy and is therefore of vital importance to the health and welfare of all Californians." (Pub. Res. Code § 25350(a).)

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[7] Section 42303 also is inadequate for another reason: it grants the District authority to request information on a case-by-case basis as part of a permitting process or enforcement action; it does not give the District a blank check to pass new regulatory reporting requirements that apply collectively and on an ongoing basis. Section 42303 appears in the chapter of regulations that governs "enforcement," in the Article governing "permits," and grants authority only to an "air pollution control officer," not to the District at large. (H&S Code § 42303.) This limitation on Section 42303 is underscored by the context of the only case addressing it. (See *Soranno's Gasco, Inc. v. Morgan*, (9th Cir. 1989) 874 F.2d 1310 (suspending source's operating permit "under the authority of California Health & Safety Code §§ 42303 and 42304" after facility failed to respond to an information request).)

While PIIRA requires refineries to submit extensive data to the CEC, the Legislature also acknowledged the extremely sensitive nature of this information by including in PIIRA extremely detailed and thorough protections related to confidentiality of crude slate and other data. All information submitted to the CEC under PIIRA is presumptively confidential and is aggregated to further ensure confidentiality. (Pub. Res. Code § 25364(b).) If the release of non-aggregated information is requested, PIIRA requires notice to the entity who submitted the information, an opportunity to respond, and a written explanation by CEC of any determination to release or not release non-aggregated data. (Pub. Res. Code § 25364(c).) The CEC also is prohibited from utilizing non-aggregated data on petroleum products and blendstocks for any purpose other than the statistical analysis, and is prohibited from disclosing that information to anyone other than CEC members and staff. (Pub. Res. Code § 25364(f); see also C.C.R. Title 20 § 1370(a) (PIIRA regulations clarifying that "CEC staff and support staff assigned to collect or analyze data submitted in confidence, pursuant to this article, will hold unaggregated PIIRA data confidential.").)

In short, when it enacted PIIRA, the Legislature created an extensive, economy-wide, state-level reporting system for petroleum products and crude oil that "fully occupies" the area of petroleum products and crude oil reporting across California and preempts local and regional agency action directed at the same type of data. (See *Cal. Water & Tel. Co. v. Los Angeles County* (1967) 253 Cal.App.2d 16, 27 ("[i]f the subject matter or field of the legislation has been fully occupied by the state, there is no room for supplementary or complementary local legislation.").)

The Legislature's intent to establish PIIRA as the *exclusive* mechanism for reporting petroleum product and crude oil information is plain on the face of the statute. The *only* agency authorized to receive this information is the CEC; PIIRA further expressly limits CEC's disclosure of this information to *only* the California Air Resources Board ("ARB"), and then *only* "if [ARB] agrees to keep the information confidential." (Pub. Res. Code § 25364(g).) Had the Legislature intended to grant local air district access to this data, it could easily have done so when it amended PIIRA over the years, but it chose not to.

The information required by Rule 12-15 is nearly identical to the data that refineries are required to report to the CEC (including, among other things, monthly data related to crude oil, blendstocks, and refined products, along with related information such as sulfur content and API[8] gravity). (*Compare* C.C.R. Title 20 App. A, B (describing contents of weekly and monthly PIIRA reports) *with* AR Doc. 4, at 000706 (Rule 12-15, § 12-15-408, describing requirements for monthly crude slate reports).) At the same time, Rule 12-15 undermines PIIRA's confidentiality protections by first requiring refineries to identify any confidential information, and then placing the burden on refineries to justify and defend the confidentiality of that information if the data is requested. (See AR Doc. 4 at 000702-07 (Rule 12-15).) This is exactly backwards of how the California Legislature structured the confidentiality protections of PIIRA to avoid disclosure of sensitive information by treating crude slate data as presumptively confidential. Rule 12-15's lack of confidentiality provisions creates a real risk that the District will disclose individualized petroleum and crude oil data that could be used by Petitioners' competitors or suppliers to engage in anti-competitive behavior, fix crude oil prices, or otherwise harm the California petroleum markets.[9]

Rule 12-15 intrudes upon an area of law wholly occupied by PIIRA and directly conflicts with fundamental provisions designed by the California Legislature to protect the confidentiality of petroleum data and limit its disclosure. As the Court of Appeal has explained, "[i]f the preemption doctrine means anything, it means that a local entity may not pass an ordinance, the effect of which is to completely frustrate a broad, evolutional statutory regime enacted by the Legislature." (*Fiscal v. City and County of S.F.* (2008) 158 Cal.App.4th 895, 911.) For all of the foregoing reasons, the crude

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[8] American Petroleum Institute specific gravity, or "API gravity," is an inverse measure of a petroleum liquid's density relative to that of water.

[9] This is not an idle concern. Petitioners and other participants in petroleum markets are highly regulated by federal antitrust laws, and disclosure of the type of information collected by the CEC under PIIRA by two or more participants in petroleum markets, without the confidentiality protections provided by PIIRA, could expose those entities to allegations under the Sherman Act (15 U.S.C. §§ 1–7), the Clayton Act (15 U.S.C. §§ 12–27, 29 U.S.C. §§ 52–53), or Federal Trade Commission rules related to the energy market manipulations (16 C.F.R. 317), among other laws. The confidentiality provisions in Rule 12-15 are wholly inadequate to guarantee against disclosure of sensitive information by the District, which could expose Petitioners and other entities to anticompetitive behavior at best and antitrust liability at worst. (See also *324 Liquor Corp. v. Duffy* (1987) 479 U.S. 335, 345, n. 8 ("federal antitrust laws pre-empt state laws authorizing or compelling private parties to engage in anticompetitive behavior.").)

slate requirements of Rule 12-15 are preempted by PIIRA and void. (*Id.*, *Sherwin-Williams Co.*, 4 Cal.4th at 897; *Cal. Water & Tel. Co.*, (1967) 253 Cal.App.2d at 27.)

3. Federal Law Preempts the District's Efforts to Impose Requirements Related to Rail Carriers and Marine Vessels.

The District's efforts to compel refineries to report emissions from cargo carriers are similarly preempted by federal law. Rule 12-15 requires refineries to submit an "emissions inventory" to the District that includes both facility emissions and "cargo carriers (e.g. ships and trains), excluding motor vehicles, during loading or unloading operations at a Petroleum Refinery." (AR Doc. 4 at 000702 (adopting Rule 12-15 provisions).) But Petitioners have no control over independent cargo carriers and cannot force them to report emissions to refineries for purposes of passing that data along to the District. More importantly, federal law preempts any local regulation of ships and trains, as Petitioners repeatedly informed the District during rulemaking. (AR Doc. 18, at 000870-71.) Because the District cannot compel Petitioners to do what the District itself cannot, the cargo carrier provisions of Rule 12-15 are void. (*Sherwin-Williams Co.*, 4 Cal.4th at 897.)

a. *The Interstate Commerce Commission Termination Act Expressly Preempts State and Local Laws Related to Rail Transportation.*

The Interstate Commerce Commission Termination Act ("ICCTA") includes an express preemption clause that grants the federal Surface Transportation Board ("STB") "exclusive" jurisdiction over "transportation by rail carriers" and the "operation" of rail "facilities, even if the tracks are located, or intended to be located, entirely in one State." (49 U.S.C. § 10501(b)(1)-(2).) The STB's exclusive jurisdiction over rail carriers and related operations is "exclusive and preempt the remedies provided under Federal or State law." (49 U.S.C. § 10501(b).) This plain Congressional preemption of state and local laws was affirmed by the Ninth Circuit, which held that the "ICCTA 'preempts all state laws that may reasonably be said to have the effect of managing or governing rail transportation.'" (*Assn. of Am. Railroads v. S. Coast Air Quality Mgmt. Dist.* (9th Cir. 2010) 622 F.3d 1094, 1098 (internal citation omitted).)

In *Assn. of Am. Railroads* the Ninth Circuit considered whether three rules adopted by the South Coast Air Quality Management District ran afoul of the ICCTA. (*Id.* at 1096-97.) One of the rules at issue imposed emissions limits on idling trains, while the other two rules imposed various related "reporting requirements" on railyard operators. (*Id.* at 1096.) The Ninth Circuit held that the ICCTA preempted all of these regulations because they are aimed "directly [at] railroad activity, requiring the railroads to reduce emissions and to provide . . . specific reports on their emissions and inventory." (*Id.* at 1098.)[10]

Rule 12-15 imposes precisely the same kinds of requirements that the Ninth Circuit rejected. Just like the rules at issue in *Assn. of Am. Railroads,* Rule 12-15 imposes various reporting requirements on third parties (here, refineries) aimed directly at train emissions. (AR Doc. 4 at 000702.) Rule 12-15 thus has the direct "effect of managing or governing" the activity of a railway—an act that is expressly preempted by *Assn. of Am. Railroads* and the plain language of the ICCTA. (*Id.*; 49 U.S.C. § 10501(b).) The District cannot use Rule 12-15 to skirt the express preemption provisions of the ICCTA by requiring refineries to report railway emissions that the District cannot require railways themselves to report. (*Sherwin-Williams Co.*, 4 Cal.4th at 897.)

b. *The Federal Clean Air Act Preempts State and Local Laws Related to Marine Vessel Emissions.*

The District also lacks authority to regulate emissions or require reporting from marine vessels. Marine vessels are regulated by Section 209(e)(2) of the federal Clean Air Act, which requires California to obtain authorization from the EPA in advance of adopting any "standards and other requirements relating to the control of emissions" from marine vessels. (42 U.S.C. § 7543(e)(2)(A).) This is a special status conferred on California by the Clean Air Act; no other state is given a commensurate ability (nor are local air districts), and Clean Air Act Section 209 contains additional

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[10] The scope of preemption under the ICCTA is broad. The Ninth Circuit has expressly rejected the argument that preemption under the ICCTA is limited to economic regulation and has recognized that environmental regulations are preempted as well. (See e.g., *City of Auburn v. U.S.* (9th Cir. 1998) 154 F.3d 1025, 1029-32; see also *id.* at 1032 (affirming a Surface Transportation Board ruling that a railroad was not subject to local environmental permitting laws because those laws were preempted by the ICCTA).) In recognizing the breadth of preemption intended by Congress in promulgating the ICCTA, one court noted that "[i]t is difficult to imagine a broader statement of Congress's intent to preempt state regulatory authority over railroad operations." (*CSX Transportation, Inc. v. Georgia Public Service Com* (N.D. Ga. 1996) 944 F.Supp. 1573, 1581.)

express preemption provisions that underscore Congressional intent to preempt a wide range of state action aimed at mobile sources except in defined, narrow circumstances—and then only with EPA's permission. (See generally 42 U.S.C. § 7543.)

When ARB adopted marine vessel emissions standards *without* seeking EPA authorization, the Ninth Circuit held that its actions were preempted and barred by Section 209 of the Clean Air Act. (*Pacific Merchant Shipping Assn. v. Goldstene* (9th Cir. 2008) 517 F.3d 1108.) The same holds true here. The Clean Air Act preempts state action to regulate marine vessel emissions without advance authorization from EPA, and the District received no such authorization with respect to the marine vessel emissions reporting requirements of Rule 12-15.[11] (*Id.*; see also 42 U.S.C. § 7543(e)(2)(A).) Again, the District is attempting to impose requirements on refineries that the District cannot directly impose on the actual source of the emissions at issue. But because CAA Section 209 and Ninth Circuit precedent preempt the District's attempted regulation of marine vessel emissions, such provisions of Rule 12-15 are void.

V. CONCLUSION

For all of the foregoing reasons, this Court should grant the Petition and issue a writ of mandate finding Rule 12-15 preempted by state and federal law and requiring the District to: (i) vacate and set aside the Initial Study/Negative Declarations for Rules 12-15 and 9-14; (ii) comply with CEQA and H&S Code requirements in any future Refinery Project rulemaking; and (iii) vacate and set aside Rule 12-15.

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[11] The District cannot argue that marine vessel emissions are attributable to refineries and therefore exempt from the scope of Clean Air Act Section 209. The D.C. Circuit Court of Appeals has already ruled that "it is entirely implausible that a vessel's 'to-and-fro' emissions could be attributed to a marine terminal owner under any approach that the [Clean Air Act] would tolerate[.]" (*NRDC v. EPA* (D.C. Cir. 1984) 725 F.2d 761, 764.) And EPA has concluded that "[t]he 'to and fro' emissions and 'hotelling' emissions from the vessels are associated with the normal seagoing activities of the vessels and not with the industrial activities associated with the port[.]" (See AR Doc. 18 at 000871, citing Letter from C. Sheehan (EPA Region 6) to M. Cathey, El Paso Energy, and D. Dutton, Akin, Gump (Oct. 28, 2003).)

Dated: December 21, 2016

Respectfully submitted,

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PROOF OF SERVICE

I, the undersigned, declare that I am employed in the County of San Francisco; I am over the age of eighteen years and not a party to the within entitled action; my business address is Beveridge & Diamond, P.C., 456 Montgomery Street, Suite 1800, San Francisco, CA 94104-1251.

On December 21, 2016, I served the following document(s): **PETITIONERS' BRIEF IN SUPPORT OF PETITION FOR WRIT OF MANDATE** on the interested party(ies) in this action.

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The documents were served by the following means:

☒ BY ELECTRONIC TRANSMISSION: Based on an agreement of the parties to accept service by electronic transmission, I caused the documents to be sent to the person at the electronic notification address set forth above.

I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct.

DATED: December 21, 2016

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SUPERIOR COURT OF THE STATE OF CALIFORNIA

FOR THE COUNTY OF CONTRA COSTA

WESTERN STATES PETROLEUM ASSOCIATION; VALERO REFINING COMPANY—CALIFORNIA; TESORO REFINING & MARKETING COMPANY, LLC; and PHILLIPS 66 COMPANY,

Petitioners/Plaintiffs,

v.

BAY AREA AIR QUALITY MANAGEMENT DISTRICT and DOES 1 through 20, inclusive,

Respondents/Defendants.

Case No. N16-0963

PETITIONERS' REPLY BRIEF IN SUPPORT OF PETITION FOR WRIT OF MANDATE

(Code Civ. Proc §§ 1085, 1094.5)

CEQA CASE

APPENDIX B

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I. INTRODUCTION

The Bay Area Air Quality Management District (the "District") violated the California Environmental Quality Act ("CEQA") by segmenting its analysis of multiple actions that collectively comprise the District's Refinery Project. CEQA demands unified review of "the whole of the action," and a series of actions undertaken to attain the same objective constitutes a single CEQA project. (*Tuolumne County Citizens for Responsible Growth, Inc. v. City of Sonora* (2007) 155 Cal.App.4th 1214, 1226-27) (hereinafter *Tuolumne County*).) The District admits that it conceived, developed, and adopted the Phase 2 Rules[1] as part of a broader, unified effort that encompasses at least seven separate rules[2] that are collectively designed to achieve a concrete, common objective: tracking and reducing refinery emissions by 20%. (Compl. at 4:24-27, Answer at 3:21.) Under *Tuolumne County* and core CEQA precepts, the District violated CEQA when it segmented its analysis of the Phase 2 Rules and adopted them in isolation, without any consideration of other actions taken by the District to achieve the same unified objective. (*Tuolumne County*, 155 Cal.App.4th at1226-27; see also Answer at 6:15-18, District admitting that relevant rules "have been analyzed separately under CEQA".)

Rather than address Petitioners' segmentation argument head-on, the District attempts to avoid the implications of *Tuolumne County* by arguing that Petitioners' claims "lack[] a predicate project" (Resp. at 10)—in essence, arguing that Petitioners' complaint is with the District's larger policy objectives, rather than a concrete CEQA project. The District misstates Petitioners' complaint. Petitioners have not challenged any generalized public policy, or even the specific objective that the Refinery Project attempts to achieve; rather, Petitioners object to the District's *implementation* of a specific objective (a 20% reduction in refinery emissions) in a manner that circumvents CEQA. The

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[1] Regulation 12, Rule 15 ("Rule 12-15") and Regulation 9, Rule 14 ("Rule 9-14"). The District refers to these rules as the "Challenged Rules."

[2] The rules challenged here represent the second phase of rulemaking. The first phase included three rules: Regulation 6, Rule 5 ("Rule 6-5"), Regulation 8, Rule 18 ("Rule 8-18"), and Regulation 11, Rule 10 ("Rule 11-10"). This first phase also was challenged by certain petitioners in this case. (*See* Valero et al. v. BAAQMD, Case No. N16-0095). In addition to the five rules adopted during the first two phases, the District has proposed at least two additional rules as part of the Refinery Project and is considering several more.

District has expressly conceded that the Phase 2 Rules "are among several that have been publicly discussed as steps towards achieving the 20% goal of the Refinery Strategy." (Resp. at 1.) And yet nowhere has the District collectively evaluated the impacts of each step *as a whole*. Instead, the District elected to develop and adopt these rules serially, and then claim that its serial adoption justifies treating each such rule as a separate CEQA "project."

The District also asserts that the alleged "independent utility" of the Phase 2 Rules should insulate them from CEQA's requirement to review the "whole of the action." But "[t]heoretical independence is not a good reason for segmenting the environmental analysis of the two matters." (*Tuolumne County*, 155 Cal.App.4th at 1230.) No amount of Monday morning quarterbacking can alter the basic fact that the Phase 2 Rules—along with the rest of the District's "suite of regulations"—were conceived and adopted to achieve a common, specific, and targeted objective.

In addition to violating CEQA, the District exceeded its authority when it attempted to compel refineries to report (i) their confidential "crude slate" composition, and (ii) cargo carrier emissions. It is black-letter law that "administrative agencies have only the powers conferred on them" and "may not act in excess of those powers." (*Am. Fed'n of Labor v. Unemployment Ins. Appeals Bd.* (1996) 13 Cal.4th 1017, 1042, n.9, citing *Ferdig v. State Personnel Bd.* (1969) 71 Cal.2d 96, 103-04.) Here, the District lacks *any* express authority to collect crude slate data or regulate cargo carriers, and existing state and federal laws preempt the District's attempts to regulate in these fields.

The District attempts to avoid preemption by misconstruing the scope of its authority and the law of preemption. For example, the District argues that its crude slate requirements are authorized because the District's procedures provide similar protections as the state law that already regulates crude slate reporting—which also happens to grant exclusive authority over crude slate data to another agency. But even if this characterization were correct (which it is not), preemption means that the District cannot regulate in this area *at all*—not that it may regulate as long as it hews closely enough to the statutory powers granted to another agency. (See *Sherwin-Williams Co. v. City of Los Angeles* (1993) 4 Cal.4th 893, 897 (agency action preempted when it "enters an area fully occupied by general law").) Similarly, the District argues that preemption does not bar its cargo carrier requirements by asserting that it is not regulating cargo carriers at all—it is merely holding refineries responsible for cargo carrier emissions. But the District cannot do indirectly what it lacks authority to do directly: it cannot compel refineries to "regulate" cargo carriers when it cannot do so itself.

The District has failed to demonstrate its compliance with California law and its authority to adopt core provisions of Rule 12-15. Petitioners respectfully ask this Court to enforce CEQA, find crude slate and cargo carrier provisions preempted, and order the District to vacate Rule 12-15.

II. THE DISTRICT HAS FAILED TO JUSTIFY ITS ILLEGAL SEGMENTATION OF THE REFINERY PROJECT UNDER CEQA

A. The Phase 2 Rules Are Part of a Larger CEQA Project Requiring Unified Review.

The critical facts here are simple. In late 2014, the District adopted Resolution 2014-07, which established the specific, defined objective of tracking refinery emissions (in part through Rule 12-15) and reducing those emissions by 20%. (AR Doc. 194, at 004394-95.) To implement the Resolution's objective, District staff developed a unified, multi-phase approach that it labeled as its "Refinery Emission Reduction Strategy." (AR Doc. 161, at 004069-70; see also AR Doc. 694, at 011575-83 (agenda for "Refinery Emissions Reduction Strategy Kick Off Meeting").) As the concrete regulatory actions flowing from this strategy, the District developed a coordinated set of refinery-focused rules, to be adopted in several phases, that *together* would achieve the Resolution's objective. (AR Doc. 161, at 004066-70 (describing approach); AR Doc. 147, at 003909-12 (identifying "phases" of Refinery Project).) These rules—including the Phase 1 Rules, the Phase 2 Rules, and other pending rules—collectively constitute the District's Refinery Project as "various steps which taken together obtain an objective." (*Tuolumne County*, 155 Cal.App.4th at 1226-27.) The District violated CEQA when it segmented its analysis by evaluating each rule separately and expressly disclaiming any obligation to consider the impacts of the Refinery Project as a whole. (See generally AR Docs. 15, 16.)

The District attempts to avoid this conclusion by arguing that the Refinery Project is not actually a single "project" under CEQA. The District acknowledges that the adoption of the Phase 2 Rules was an "activity" that qualified as a "project" under CEQA,[3] but then argues that these rules

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[3] Compl. 17:13-16, Answer 8:26. Indeed, the District could not argue otherwise, as the adoption of environmental rules has long been acknowledged to trigger CEQA. *See, e.g., Cal. Unions for Reliable Energy v. Mojave Desert Air Quality Mgmt. Dist.* (2009) 178 Cal.App.4th 1225, 1240, citing *Wildlife*

cannot be considered the same CEQA project, because while they were each designed to achieve a common purpose, this purpose was simply a "policy goal," and not a CEQA project in and of itself. (Resp. at 6:23-25 ("What unifies the Challenged Rules is not anything that arguably meets the definition of a CEQA 'project,' but rather only the statement of a policy goal.").)

The District's argument is essentially this: in order for the Refinery Project rules to qualify as the same CEQA "project," they would themselves have to implement another, larger CEQA "project." This assertion goes far beyond what CEQA demands. All actions "taken together" to achieve a single "objective" are considered a single CEQA project—regardless of the nature of that objective, or whether the objective itself is an independent CEQA "project." A "policy goal" is, as the District asserts, inchoate and amorphous: it is not an "activity" with direct and foreseeable impacts, and so a policy goal or objective—standing alone—is not subject to CEQA. Petitioners did not challenge the Board's 2014 Resolution for precisely this reason. A CEQA "project," on the other hand, is the specific activity or set of activities that *implement* a given objective.

The 2014 Resolution established a well-defined and measurable objective (or "policy goal," as the District puts it): to track and reduce refinery emissions by 20%. Petitioners agree that the 2014 Resolution itself is not an "activity" challengeable under CEQA, because it merely established an objective and it did not "commit the agency to a definite course of action." (See Pub. Res. Code § 21080(a); CEQA Guidelines § 15352(a).) But when the District promulgated the Phase 1 and Phase 2 Rules, it transitioned from setting an objective to *implementing* that objective by adopting a set of rules—which *is* an "activity" subject to CEQA. (*Id.*) And because those rules are each "various steps taken together" to *achieve the same policy goal*—the same "objective"—they constitute a single CEQA project. (*Tuolumne County*, 155 Cal.App.4th at 1226-27; Cal. Code Regs., tit. 14, § 15378(a); *Bozung v. LAFCO* (1975) 13 Cal.3d 263, 283-84.) As the Court of Appeal has observed:

> CEQA's conception of a project is broad, and the term is broadly construed and applied in order to maximize protection of the environment. This big picture approach to the definition of a project (*i.e.*, including "'the whole of an action'") prevents a proponent or a public agency from avoiding CEQA requirements by dividing a project into smaller

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Alive v. Chickering (1976) 18 Cal.3d 190, 206; *Plastic Pipe & Fittings Assn. v. Cal. Bldg. Standards Com.* (2004) 124 Cal.App.4th 1390.)

> components which, when considered separately, may not have a significant environmental effect. That is, the broad scope of the term "project" prevents "the fallacy of division," which is the "overlooking [of a project's] cumulative impact by separately focusing on isolated parts of the whole." Environmental considerations may not be submerged by chopping a single CEQA project into smaller parts for piecemeal assessment.

(*Nelson v. County of Kern* (2010) 190 Cal.App.4th 252, 271 (citations omitted).)

The District's approval of multiple refinery regulations to achieve the common, specific, and targeted objectives of the 2014 Resolution is "an activity" that will cause a physical change in the environment and is subject to CEQA. (Pub. Res. Code § 21065.) The core issue is whether the scope of that CEQA project is limited to individual regulations, as the District alleges, or whether it includes the entire multi-phase "Refinery Project", as Petitioners assert. *Tuolumne County* and its progeny establish that the correct answer is the latter: under CEQA, a project must include ***all*** of the "various steps which taken together obtain an objective." (*Tuolumne County*, 155 Cal.App.4th at 1226-27 (quotation omitted).) The District violated this core principle when it segmented its review of the individual Refinery Project rules.

B. The Alleged "Independent Utility" of the Phase 2 Rules Does Not Justify the District's Piecemeal Review of the Refinery Project.

The District does not contest the integrated nature of the rules it has conceived and adopted as part of its Refinery Strategy; nor does it contest the holding of *Tuolumne County*. Instead, the District argues that the alleged "independent utility" of the Phase 2 Rules somehow insulates them from CEQA review. (Resp. at 7:9-8:3.) Specifically, the District asserts that each of the Phase 2 Rules has some degree of "independent utility" that, in the District's words, "has been articulated as an indication that separate CEQA review of separate actions is appropriate." (Resp. at 7:16-18). In support of this proposition, the District cites two cases: *Del Mar Terrace Conservancy Inc. v. City Council of San Diego* (1992) 10 Cal.App.4th 712 (hereinafter *Del Mar Terrace*)[4] and *Banning Ranch Conservancy v. City of Newport Beach* (2012) 211 Cal. App. 4th 1209. Neither case supports the District's argument.

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[4] *Del Mar Terrace* also is not directly controlling here because it addressed the required environmental review for highway projects. (*Del Mar Terrace*, 10 Cal.App.4th at 732.) As the court made clear, the version of the "independent utility" test it applied was derived from federal case law and "is specific to

Del Mar Terrace is inapposite to the facts presented in this case. *Del Mar Terrace* involved the sufficiency of an Environmental Impact Report ("EIR") related to a roadway project in Carmel, California known as the "56 West" project. (*Del Mar Terrace*, 10 Cal.App.4th at 719.) The 56 West project was one of five roadway projects that the local government sought to implement in phases; future anticipated projects included the 56 East project, followed by a possible four-mile Future Urbanizing Area ("FUA") project to link the 56 East and 56 West projects. (*Id.* at 731.) The EIR for the 56 West project evaluated the "worst-case" environmental impacts that might occur if the FUA were developed, but did not comprehensively analyze all aspects of the FUA, since its development was highly speculative. (*Id.* at 721-23, 731.) The petitioners nevertheless argued that the EIR for the 56 West project was insufficient because it did not include a complete analysis of the *potential* FUA project. (*Id.*) The court rejected this challenge, finding the EIR sufficient because the 56 West project was designed to independently relieve congestion in a certain area, because there was not yet any "defined project to [expand] SR 56 through the . . . FUA," and because the EIR did, in fact, evaluate the worst-case impacts associated with the potential future development of the FUA. (*Id.* at 732-37.)

None of the considerations of *Del Mar Terrace* apply here. The Refinery Project rules—including the Phase 2 Rules—were not developed in isolation to achieve independent objectives. As the District admits, they were developed as part of the District's unified strategy to achieve the mandates set out in Board Resolution 2014-07.[5] Nor are the Refinery Project rules highly speculative, uncertain, or contingent on future events: the District's Board has already approved the scope and goals of the Refinery Strategy, and the District has already promulgated five rules (including the Phase 2 Rules) as the first phases of its Refinery Project (while improperly evaluating each of those rules in isolation). Perhaps most importantly, the District has made *no* attempt to evaluate the "worst-case"

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roads." (*Del Mar Terrace*, 10 Cal.App.4th at 732 (citing and discussing *Daly v. Volpe* (9th Cir. 1975) 514 F.2d 1106).) There is no roadway project at issue in this case.

[5] The connectivity of these rules is further reinforced by the District's stated intention to use data collected through Rule 12-15 to implement proposed Rule 12-16 and proposed Rule 13-1 (which is effectively a substitution for, or an extension of, the previously-proposed Rule 12-16). In fact, the District concedes that Rule 12-16, as previously proposed, was "functionally dependent on the version of Rule 12-15 proposed at the same time." (Resp. at 7:25-28.)

impacts associated with future Refinery Project actions. Unlike the EIR prepared in *Del Mar Terrace*, the Negative Declarations issued in conjunction with the Phase 2 Rules expressly limit their analysis to each individual rule and disclaim *any* obligation to consider the cumulative impacts arising from its Refinery Project as a whole or any other related rule or action. (AR Doc. 15 (negative declaration for Rule 9-14); AR Doc. 16 (negative declaration for Rule 12-15).)

In relying on *Del Mar Terrace*, the District conflates the "independent utility" test with CEQA's requirement to evaluate "integral" activities as part of the same CEQA project. (See *No Oil, Inc. v. City of Los Angeles* (1987) 196 Cal.App.3d 223; *Sierra Club v. West Side Irrigation Dist.* (2005) 128 Cal.App.4th 690, 698.) But any argument that the Challenged Rules can "stand alone" does not remove them from CEQA's requirement to evaluate the "whole of the action" because:

> when one activity is an integral part of another activity, the combined activities are within the scope of the same CEQA project. [Parties go] astray, however, by inverting this principle. The idea that all integral activities are part of the same CEQA project does not establish that *only* integral activities are part of the same CEQA project.

(*Tuolumne County*, 155 Cal.App.4th at 1229 (emphasis added).) In other words, the "integral activities" concept does not contract the scope of CEQA—it expands it—and the "independent existence of the two actions cease[s] for purposes of CEQA" when both actions are steps towards a well-defined common objective. (*Id.* at 1231.)

The District fares no better with *Banning Ranch*. In that case, petitioners challenged an EIR adopted for the development of Sunset Ridge Park, in the City of Newport Beach, alleging that it wrongfully excluded consideration of "the pending residential and commercial development on an adjacent property, Banning Ranch." (*Banning Ranch Conservancy*, 211 Cal. App. 4th at 1214.) The court rejected petitioners' claims, holding that the Banning Ranch development was not a "reasonably foreseeable consequence of the park." (*Id.*) In doing so, the court noted that "piecemealing case law defies easy harmonization" and grouped impermissible piecemealing cases into two general categories. (*Id.* at 1223.) According to the court, there may be improper piecemealing when:

- "the purpose of the reviewed project is to be the first step toward future development" (*Id.*, citing *Laurel Heights Improvement Ass'n v. Regents of Univ. of Cal.* (1988) 47 Cal.3d 376, and its line of cases); and also when

- "the reviewed project legally compels or practically presumes completion of another action." (*Banning Ranch Conservancy*, 211 Cal. App. 4th at 1214, citing *Nelson v. County of Kern*, 190 Cal.App.4th at 272, *Tuolumne County*, 155 Cal.App.4th at 1231, and related cases).

The *Banning Ranch* court went on to evaluate the petitioners' claims based only on the *first* type of piecemealing analysis (the "first step" doctrine of *Laurel Heights*), ultimately concluding that there was no piecemealing because Banning Ranch and the park had "different project proponents", "serve different purposes", and were not dependent on each other for the fulfillment of any larger goal. (*Banning Ranch,* 211 Cal. App. 4th at 1223.) None of those considerations apply here. In this case, the record amply demonstrates a series of coordinated actions, taken by the same project proponent (the District), to collectively achieve a common, larger goal (a 20% reduction in refinery emissions).

The *Banning Ranch* court did not even evaluate the second type of piecemealing, where one action "practically presumes completion of another action." (*Id.* at 1223.) That is the scenario presented by the Refinery Project: each of the Phase 1 and Phase 2 Rules were jointly developed and adopted by the District in a coordinated fashion that plainly "presumes completion" of other actions (*i.e.*, the contemporaneous or later adoption of the other rules) in order to achieve the District's overarching objective of reducing refinery emissions by 20%. The District made this quite clear in numerous internal documents and public presentations that specifically describe the Refinery Project as comprised of multiple phases, each with several individual rules, which build upon each other to achieve the 20% reduction objective. (See, e.g., AR Doc. 147, at 003909, 003911; AR Doc. 30, at 001090-91.) Contrary to the District's argument, *Banning Ranch* is entirely consistent with *Tuolumne County*, and both cases reject the idea that theoretical independence can justify the segmentation of related actions.

The concept of "independent utility" was fully considered in *Tuolumne County*. There, Lowe's (the project proponent) argued that its construction of a store and a road realignment were independent actions and did not require unified CEQA analysis because "they could 'be implemented independently of each other.'" (*Tuolumne County*, 155 Cal.App.4th at 1229.) The court squarely rejected that argument, noting that "[Lowe's] places too much importance on theoretical possibilities at the expense of what actually is happening." (*Id.* at 1230.) The same is true here: while the District argues that the

Phase 2 Rules could "stand alone functionally" and are not "dependent" on other Refinery Project rules (Resp. at 7:11-12), that simplistic statement fails to reflect "what is actually happening" in this case—namely, the coordinated development, adoption, and implementation of a suite of rules all aimed at achieving a single objective. (*Tuolumne County,* 155 Cal.App.4th at 1230 ("Theoretical independence is not a good reason for segmenting the environmental analysis of the two matters").) The District cannot hide behind the theoretical independence of Rule 12-15 and Rule 9-14 to argue that they are exempt from CEQA's mandate to review "the whole of the action."

"[W]here distinct actions are closely related to same overall objective, or if success of the overall objective depends on the inclusion of certain action, the distinct actions are viewed as parts of a larger whole—the same [CEQA] project." (*Nelson*, 190 Cal.App.4th at 271, citing *Tuolumne County*, 155 Cal.App.4th at 1225–1231; see also *Tuolumne County*, 155 Cal.App.4th at 1226.) The District admits that its Refinery Project rules each represent a component of its unified strategy to track and reduce refinery emissions by 20%. (Compl. at 4:24-27, Answer at 3:21). Further, no single Refinery Project rule is sufficient on its own to achieve that objective. (See AR Doc. 2, at 000561 (discussing additive contributions of various rules towards the 20% reduction objective).) Notwithstanding the clear and well-documented relationship of each Refinery Project rule to the "same overall objective," the District failed to prepare an EIR for the Refinery Project *as a whole*.[6] Instead, the District reviewed each of the Phase 2 Rules independently, concluded that each rule had no significant environmental impact, and adopted individual negative declarations. (AR Docs. 15, 16.) In doing so, the District "chopped up" the Refinery Project and violated CEQA.

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[6] The District's recent actions further underscore the integrated and ongoing nature of the Refinery Project. In March 2017, the District published a draft EIR for Rules 12-16 and 11-18. (http://www.baaqmd.gov/~/media/files/planning-and-research/rules-and-regs/workshops/2017/reg-12-deir-pdf.pdf?la=en.) Previously, the District had combined its CEQA analysis for Rule 12-16 with Rule 12-15, but then severed that analysis when it adopted Rule 12-15. The District's uncoupling of Rule 12-15 from Rule 12-16, and subsequent reattachment of Rule 12-16 to Rule 11-18, reinforces the integrated nature of the District's Refinery Project rulemaking actions.

C. The District Cannot Avoid Its CEQA Obligations By Claiming Administrative Inconvenience.

The District complains that conducting a unified CEQA review for the Refinery Project would be "as a practical matter . . . perplexing." (Resp. at 10:18-19.) The District raises the specter of an agency tied in knots, stuck in an endless loop of CEQA reviews each time it engages in a new regulatory initiative. The District's argument is a strawman. Petitioners never argued that CEQA requires justification for the District's planning activities; Petitioners seek only a unified review of the impacts arising from the suite of regulations that the District *itself* identified as the mechanism by which it intended to implement the Refinery Strategy.[7] (See, e.g., AR Doc. 694, at 011575-83; *id.* at 011577-78; AR Doc. 161, at 004066-70; AR Doc. 147, at 003909-12; AR Doc. 56, at 002194.)

Nor is the District's Refinery Project aimed at a generalized public policy, such as "improving air quality," as the District seems to suggest. To the contrary, the District developed the Refinery Project to achieve the specific, targeted objectives it identified in the 2014 Resolution. The Phase 2 Rules are one of the steps needed to implement and achieve those specific and targeted objectives (in conjunction with the Phase 1 Rules, and additional future rules). At a minimum, the District could easily have conducted a comprehensive review of the two Phase 2 Rules and incorporated into that analysis the cumulative impacts associated with its already-adopted Phase 1 Rules—yet the District failed to undertake even this minimal additional effort.

Projects often occur in multiple phases or components, but that does not excuse an agency from CEQA's mandate to evaluate "the whole of the action." (*Cal. Union for Reliable Energy v. Mojave Desert Air Quality Mgmt. Dist.* (2009) 178 Cal.App.4th 1225, 1242.) If the District were interested in finding "practical" solutions, CEQA provides clear paths to do so. For example, among other things the CEQA Guidelines provide that:

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[7] All projects have their origins in an idea or mandate, whether it is the District's Board resolution to reduce refinery emissions by 20%, or a corporate board resolution to build a new shopping center. In each case, numerous planning stages ensue, during which the project's proponents plan a path towards achieving their ultimate goal. For CEQA purposes, the culmination of that planning process is the approvals necessary for the project to proceed—approvals that trigger CEQA's requirement to assess the environmental impacts of the entire project. (See CEQA § 21065 (defining a CEQA "project" to include agency actions that have a direct or foreseeable indirect effect on the environment).)

> Where individual projects are, or a phased project is, to be undertaken and where the total undertaking comprises a project with significant environmental effect, the lead agency shall prepare a single program EIR for the ultimate project as described in Section 15168. Where an individual project is a necessary precedent for action on a larger project, or commits the Lead Agency to a larger project, with significant environmental effect, an EIR must address itself to the scope of the larger project. Where one project is one of several similar projects of a public agency, but is not deemed a part of a larger undertaking or a larger project, the agency may prepare one EIR for all projects, or one for each project, but shall in either case comment upon the cumulative effect.

(CEQA Guidelines § 15165.) As the Guidelines make clear, the fact that a project may occur over time or in multiple phases does not excuse an agency from evaluating all project actions in a comprehensive manner. (*Id.*) Instead, CEQA expressly provides various mechanisms to facilitate evaluation of multi-phase projects, which discredit the District's concerns.

For example, the District could have prepared a program EIR. (CEQA Guidelines § 15168.) Among other things, a program EIR is appropriate for "actions that can be characterized as one large project" and are "logical parts in the chain of contemplated actions." (*Id.*) Other mechanisms to aid agencies in multi-component projects include "tiering" EIRs (CEQA Guidelines § 15152), "staging" EIRs (CEQA Guidelines § 15167), and creating a "master" EIR (CEQA Guidelines §§ 15175-15179.5.) The common thread running through each of these options is that agencies are not excused from evaluating cumulative impacts arising from "the whole of the action" merely because the project may occur in multiple stages or over an extended timeline.

The District is well aware of these options—its own CEQA Guidelines specifically contemplate the use of these procedures. Among other things, the District's Guidelines provide that:

> Lead agencies may analyze and mitigate the significant effects of greenhouse gas emissions at a programmatic level, such as in a general plan, a long range development plan, or a separate plan to reduce greenhouse gas emissions. Later project-specific environmental documents may tier from and/or incorporate by reference that existing programmatic review. Project-specific environmental documents may rely on an EIR containing a programmatic analysis of greenhouse gas emissions as provided in section 15152 (tiering), 15167 (staged EIRs) 15168 (program EIRs), 15175-15179.5 (Master EIRs), 15182 (EIRs Prepared for Specific Plans), and 15183 (EIRs Prepared for General Plans, Community Plans, or Zoning).

(BAAQMD, CEQA Guidelines at 4-7 (2012).)[8] Emphasizing this point, the District recently published on its website a draft program EIR for its 2017 Clean Air Plan, explaining that:

> A program EIR also plays an important role in establishing a structure within which CEQA reviews of future related actions can be effectively conducted. This concept of covering broad policies in a program EIR and incorporating the information contained therein by reference into subsequent EIRs for specific projects is known as "tiering" (CEQA Guidelines §15152). A program EIR will provide the basis for future environmental analyses and will allow project-specific CEQA documents to focus solely on the new effects or detailed environmental issues not previously considered.

(BAAQMD, Draft 2017 Clean Air Plan § 1.2.2 (Feb. 17, 2017).)[9]

The District's organization of its own regulations is a matter of administrative convenience—there is no necessity for the District to adopt regulatory requirements separately. In effect, the District argues that it should be able to package its regulatory efforts however it likes, and to evaluate each regulatory action or rule in complete isolation from all others. Taken to its logical conclusion, the District's argument would permit it to segment any regulatory effort into many smaller regulations, minimize the perceived impacts by reviewing each component in isolation, and avoid a cohesive review of the "whole of the action." This outcome would make the District the sole arbiter of whether and to what extent CEQA review is required for any rulemaking action, and is exactly what CEQA prohibits. (CEQA Guidelines § 15378(a); *Bozung*, 13 Cal.3d at 283-84; *Nelson*, 190 Cal.App.4th at 271; *Laurel Heights Improvement Ass'n,* 47 Cal.3d at 396.)

Because each rule adopted as part of the Refinery Project is part of a cohesive plan to achieve a single, defined objective, the Phase 2 Rules—along with the previously adopted Phase 1 Rules—collectively form a single CEQA project. (*Tuolumne County*, 155 Cal.App.4th at 1226.) The District violated CEQA when it adopted these rules without analyzing them in concert, and it continues to violate CEQA by adopting and proposing new Refinery Project rules in isolation. (*Id.*; *Laurel Heights Improvement Ass'n,* 47 Cal.3d at 396.)

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[8] http://www.baaqmd.gov/~/media/files/planning-and-research/ceqa/baaqmd-ceqa-guidelines_final_may-2012.pdf?la=en.

[9] http://www.baaqmd.gov/~/media/files/planning-and-research/plans/2017-clean-air-plan/2017plandrafteirpdf-pdf.pdf?la=en.

III. THE DISTRICT HAS FAILED TO DEMONSTRATE THAT IT HAS AUTHORITY TO COLLECT CRUDE SLATE DATA OR REGULATE CARGO CARRIERS

Two core provisions of Rule 12-15 are preempted by state and federal law. First, California's Petroleum Industry Information Reporting Act ("PIIRA") occupies the field with respect to the collection of "crude slate" information, and grants *exclusive* authority to collect such information to the California Energy Commission ("CEC"). (Pub. Res. Code §§ 25350-25366; Cal. Code Regs., tit. 20 §§ 1361-1371.) Second, the District lacks any express authority to regulate cargo carriers (such as marine vessels and trains) and several state and federal laws preempt its efforts to do so. The District brushes these issues aside, asserting that Petitioners' concerns with respect to PIIRA preemption are based only on what it calls "minor procedural variations," and that the District is not actually regulating cargo carriers by requiring refineries to do so—an argument that both the D.C. Circuit and the U.S. Environmental Protection Agency ("EPA") have rejected.

The Supremacy Clause of the United States Constitution requires state and local laws to yield to federal law. (U.S. Const., art. VI, cl. 2; *Gibbons v. Ogden* (1824) 22 U.S. 1, 2 (federal laws "are supreme, and the State laws must yield to that supremacy").) The Supremacy Clause gives rise to "well-known principles of pre-emption." (*Douglas v. Seacoast Products, Inc.* (1977) 431 U.S. 265, 272.) And "when Congress has unmistakably ordained that its enactments alone are to regulate a part of commerce, state laws regulating that aspect of commerce must fall." (*Jones v. Rath Packing Co.* (1977) 430 U.S. 519, 525 (internal quotations and annotations omitted).) The California Supreme Court has set forth similar preemption principles, holding that local law is preempted when it (i) conflicts with a state law, (ii) duplicates state law, (iii) contradicts state law, or (iv) "enters an area fully occupied by general law, either expressly or by legislative implication." (*Sherwin-Williams Co.*, 4 Cal.4th at 897-98.) The District's adoption of crude slate and cargo carrier provisions in Rule 12-15 falls squarely within these bedrock principles, and is void. (See generally *County of San Diego v. Bowen* (2008) 166 Cal.App.4th 501 (agency action is void if preempted by an act of the Legislature).)

A. PIIRA Preempts Rule 12-15's Crude Slate Reporting Requirements for Two Distinct Reasons.

The crude slate reporting provisions of Rule 12-15 are preempted for two distinct reasons. First, when it enacted PIIRA the California Legislature fully occupied the field of reporting petroleum and crude oil information. Second, and independently, Rule 12-15 conflicts with and undermines core protections of PIIRA enacted by the Legislature to protect highly sensitive information. In its Response, the District asserts that Petitioners' arguments are based only on "minor procedural variations" between PIIRA and Rule 12-15 with respect to the treatment of confidential data. (Resp. 21:26-22:1). That statement entirely ignores basic preemption principles, the breadth and scope of PIIRA, the plain intent of the Legislature, and the cavalier approach the District has taken with respect to highly sensitive information protected by PIIRA.

1. PIIRA Occupies the Field of Crude Oil Reporting and Rule 12-15's Intrusion Into That Field is Unauthorized and Illegal.

PIIRA was intended by the Legislature as the exclusive mechanism for collecting crude oil data in California. The name alone—the "Petroleum Industry Information Reporting Act"—plainly indicates the content of the law and its scope, and PIIRA expressly provides that it was established for the purpose of collecting "information and data concerning ***all aspects*** of the petroleum industry." (Pub. Res. Code § 25350(c).) Notably, PIIRA grants authority to collect such data to a single state agency—the CEC. The Legislature granted no other agency co-extensive authority. The *only* agency to which the CEC may even disclose crude slate data is the California Air Resources Board ("ARB") and then only "if [ARB] agrees to keep the information confidential." (Pub. Res. Code § 25364(g).) There is no mention of the District (or any other air district) in PIIRA—an exclusion that, by its terms, prohibits transmission of crude slate data by the CEC to the District.

PIIRA is comprehensive, covering a wide range of entities (including refineries), feedstocks, blendstocks, petroleum products, and other related data. (See generally Pub. Res. Code § 25354.) Under PIIRA, refineries submit weekly, monthly, and annual data on a wide range of parameters specified in CEC's implementing regulations. (Cal. Code Regs. tit. 20 §§ 1361-1371, App. A.) The Legislature tasked CEC with analyzing and interpreting this data for, among other things, "economic and environmental impacts" related to petroleum supply and "efforts of the petroleum industry to expand refinery capacity and to make acquisitions of additional supplies of petroleum and petroleum products." (Pub. Res. Code § 25356(a)(2),(7).) In short, PIIRA establishes an extensive state-wide scheme for collecting and analyzing all manner of data related to crude oil, petroleum products, blendstocks, and other related substances.

"If the subject matter or field of the legislation has been fully occupied by the state, there is no room for supplementary or complementary local legislation." (*Cal. Water & Tel. Co. v. Los Angeles County* (1967) 253 Cal.App.2d 16, 27.) Had the Legislature intended to grant the District authority to collect crude slate data, it could easily have done so when it amended PIIRA over the years, but it chose not to. Indeed, the Legislature has considered—*and expressly rejected*—amendments to PIIRA that would have allowed the CEC to disclose information it collects under PIIRA to "other governmental agencies which have a need for that information related to their official functions." (See Assem. Bill No. 3777 (1991-1992 Reg. Sess.), amended by the Senate on June 3, 1992.) The Legislature did *not* enact this provision, and PIIRA continues to prohibit disclosure to the District. PIIRA occupies the field of petroleum and crude slate reporting in California—to the exclusion of any regulations adopted by the District—and preempts the crude slate requirements of Rule 12-15.

2. Rule 12-15 Conflicts With and Undermines PIIRA.

Even if PIIRA did not entirely occupy the field of crude slate reporting, the District's efforts to regulate in this area directly conflict with and undermine vital provisions of PIIRA intended to protect sensitive information and California consumers. As Petitioners have explained, PIIRA contains extensive provisions aimed at preventing the disclosure and improper use of petroleum data. (See Pet'rs' Br. 23:5-26:2.) The District attempts to minimize these concerns, pointing to what it calls are mere "minor procedural variations" between Rule 12-15 and PIIRA. (Resp. 21:28.) But at the same time, the District concedes that, with respect to confidentiality:

> The most substantial difference between PIIRA and the Air District's procedures appears to be that, under PIIRA, the CEC can decide not to release information it deems confidential (which decision presumably can be challenged in court). The Air District's procedures, by contrast, require it to release requested information unless a court injunction is obtained. . . *Under Air District procedures, the Refineries must be proactive in seeking judicial relief. Under PIIRA, the Refineries may be reactive.*

(Resp. 24:20-27 (emphasis added).) Notwithstanding its attempts to minimize this issue, the District seems to *agree* with Petitioners that Rule 12-15 completely inverts the confidentiality and disclosure requirements carefully considered by the Legislature and included in PIIRA.

The District's statement also understates the significant differences between PIIRA and Rule 12-15. PIIRA expressly prohibits the CEC from utilizing non-aggregated data for ***any*** purpose other than the statistical analysis, and from disclosing that information ***to anyone other than CEC members and staff***. (Pub. Res. Code § 25364(f); see also Cal. Code Regs. tit. 20 § 1370(a).) Rule 12-15 contains no such protections; indeed, the District admits that the *only* protections afforded to crude slate data collected under Rule 12-15 derive from California's generalized Public Records Act, which does not—in the District's own words—"address procedures for determining what qualifies as trade secret." (Resp. 23:5-10.)

It is readily apparent that by adopting Rule 12-15, the District intends to collect crude slate data similar or identical to that collected under PIIRA, while affording it none of the protections ensured by PIIRA. When '"local legislation conflicts with state law, it is preempted by such law and is void."' (*Sherwin-Williams Co.* 4 Cal.4th 893, 897, quoting *Candid Enterprises, Inc. v. Grossmont Union High School Dist.* (1985) 39 Cal.3d 878, 885; accord, *IT Corp. v. Solano County Bd. of Supervisors* (1991) 1 Cal.4th 81, 90; *People ex rel. Deukmejian v. County of Mendocino* (1984) 36 Cal.3d 476, 484; *Lancaster v. Municipal Court* (1972) 6 Cal.3d 805, 807.) A local air district cannot subvert the will of the Legislature by adopting regulations that entirely circumvent the protections granted by the Legislature. "If the preemption doctrine means anything, it means that a local entity may not pass an ordinance, the effect of which is to completely frustrate a broad, evolutional statutory regime enacted by the Legislature." (*Fiscal v. City and County of S.F.* (2008) 158 Cal.App.4th 895, 911.) Because the crude slate provisions of Rule 12-15 frustrate the goals and protections of PIIRA, they are preempted by PIIRA and void. (See *County of San Diego,* 166 Cal.App.4th 501.)

3. The District Has No Authority to Collect Crude Slate Data.

In a further effort to justify the crude slate provisions of Rule 12-15, the District points to two highly generalized provisions in the H&S Code, neither of which contain any express grant of authority to collect crude slate data, and neither of which operate to displace PIIRA.

The District cites H&S Code Sections 42303 and 41511 as its underlying grant of authority to collect crude slate data. But as the District concedes, its authority under these provisions is limited to "emissions" and "air contaminants." (See Resp. 16:7-25; H&S Code §§ 42303, 41511.) Rule 12-15, on the other hand, directly compels the disclosure of highly confidential raw material and feedstock composition. While the District now argues that collecting crude slate data is a "reasonable measure" for assessing air pollution (Resp. 16:5-20:11), this litigation position directly conflicts with the District's prior statements in the record that a refinery's crude slate has an "uncertain[]" relationship to "refinery air emissions" (AR Doc. 2, at 000291).[10] The District is entitled to no deference on whether its choice was "reasonable" because "[a] court does not . . . defer to an agency's view when deciding whether a regulation lies within the scope of the authority delegated by the Legislature." (*Yamaha Corp. of Am. v. State Bd. of Equalization* (1998) 19 Cal.4th 1, 11, n. 4) (citation and quotation omitted).)

More importantly, the extremely generalized provisions of the H&S Code cited by the District do not allow the District to circumvent PIIRA. When it enacted PIIRA, the Legislature expressly granted exclusive authority to the CEC with respect to the collection of data related to crude oil, petroleum products, blendstocks, and related items. The Legislature has chosen ***not*** to grant the District any similar authority and "a specific statute will not be controlled or nullified by a general one." (*Morton v. Mancari* (1974) 417 U.S. 535, 550-51; see also *Sherwin-Williams Co.*, 4 Cal.4th at 897 ("If otherwise valid local legislation conflicts with state law, it is preempted by such law and is void.").)[11]

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[10] The District also points to the New Source Review ("NSR") program as evidence of legislative intent to allow the District to collect crude slate data. (Resp. 17:11-21.) The District fails to note, however, that the federal definitions incorporated into the District's NSR program do *not* consider most changes in fuels and raw materials to be "modifications" that would trigger NSR. *See* 40 C.F.R. § 51.165(a)(1)(v)(C). Furthermore, most refineries are designed to handle a particular crude oil blend (within narrow parameters), and changes to that configuration would necessitate a physical redesign of certain refinery components, which is outside the scope of the NSR program. (See *Helping Hand Tools v. U.S. Environmental Protection Agency* (9th Cir. 2016) 848 F.3d 1185 (discussing NSR program and its scope).)

[11] Petitioners also have challenged other findings made by the District with respect to Rule 12-15, including findings that the rule is necessary and does not duplicate or interfere with requirements imposed by state or federal law. (See Pet'rs' Br. 17:1-21:2; see also H&S Code § 40727(b)(1),(4)-(5).) The District concedes that its findings are subject to judicial review based on an "arbitrary and

B. The District Concedes That it Has No Authority To Regulate Cargo Carriers.

The District has not even responded to Petitioners' preemption arguments related to the cargo carrier requirements of Rule 12-15. Instead, the District attempts to avoid preemption by arguing that Rule 12-15 does not actually regulate cargo carriers. In effect, the District's position is that even though it lacks authority to regulate or collect emissions data from cargo carriers directly, it may regulate them indirectly by compelling refineries to "estimate" cargo carrier emissions through "observations by refinery staff combined with assumptions regarding the type of equipment being used by cargo carriers." (Resp. 26:28-27:2.)

This is a remarkable position. As the District concedes, the refineries cannot compel cargo carriers to provide them with emissions data, and "it is unknown at this point to what extent cargo carriers will cooperate with Refineries in providing emissions-related information to the air District." (Resp. at 25:18-20.) What the District seeks, then, is to have the refineries take a *guess* at cargo carrier emissions, report their guesses to the District, then be held legally accountable for the accuracy of those guesses.[12]

The District's approach to cargo carrier emissions is at best arbitrary and capricious. Given the complete lack of any mechanism by which the refineries can compel accurate data from unrelated third parties, there is simply no way to ensure that "guesstimates" provided by refineries will provide information that is sufficiently accurate to support any future emissions analysis or regulatory efforts by the District. Further, should the District pursue enforcement against the refineries for insufficiently accurate guesstimates, such a claim would raise significant due process concerns, given that the District

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capricious" standard. (Resp. 12:2-24.) To survive that standard, the District must support its findings with substantial evidence in the record that is "reasonable, credible, and of solid value." (*Plastic Pipe and Fittings Assn.*, 124 Cal. App. 4th at 1407.) In its Response, the District cites approximately 24 pages of two documents in the Administrative Record in support of its conclusions. (See Resp. 12:25-21:19). Petitioners have previously argued that the Record contains little more than conclusory assertions that do not support the District's mandatory findings under the H&S Code. (Pet'rs' Br. 17:1-21:2) Petitioners assert that the record speaks for itself on these issues, and fails to satisfy the District's obligation to make H&S Code findings based on "substantial evidence."

[12] Tellingly, Petitioners are unaware of any District efforts to require other facilities or industries to gather and report emissions data related to cargo carriers visiting those facilities.

has provided no means by which refineries can compel the production of the information for which they are to be held accountable.

Of even greater concern, the District cannot compel a refinery to do what the District itself cannot. As the D.C. Circuit has held under the Clean Air Act, marine vessel emissions cannot be attributed to a stationary source like a refinery. (*NRDC v. EPA* (D.C. Cir. 1984) 725 F.2d 761, 764 ("it is entirely implausible that a vessel's 'to-and-fro' emissions could be attributed to a marine terminal owner under any approach that the [Clean Air Act] would tolerate."). Similarly, EPA has concluded that "[t]he 'to and fro' emissions and 'hotelling' emissions from the vessels are associated with the normal seagoing activities of the vessels and not with the industrial activities associated with the port[.]" (See AR Doc. 18, at 000871, citing Letter from C. Sheehan (EPA Region 6) to M. Cathey, El Paso Energy, and D. Dutton, Akin, Gump (Oct. 28, 2003).) And, in the absence of express EPA authorization, the Clean Air Act prohibits the District from regulating marine vessels. (*Pacific Merchant Shipping Assn. v. Goldstene*, (9th Cir. 2008) 517 F.3d 1108.)

The District's lack of authority in the context of trains is equally clear: the Interstate Commerce Commission Termination Act ("ICCTA") expressly preempts and prohibits the District from regulating rail carriers in any fashion. (49 U.S.C. § 10501(b).) That prohibition extends to the exact scenario presented here: the Ninth Circuit has previously rejected attempts by an air district to require a third-party entity to collect and report railroad emissions data. (*Assn. of Am. Railroads v. S. Coast Air Quality Mgmt. Dist.* (9th Cir. 2010) 622 F.3d 1094, 1098.) Just like the air district rules considered in *Assn. of Am. Railroads*, Rule 12-15 seeks to compel a third party (refineries) to undertake an activity (collecting and reporting railroad emissions) that the District itself is expressly *prohibited* from undertaking. *Assn. of Am. Railroads* squarely blocks the District's attempt to conduct an end-run around the ICCTA.

The District cannot delegate to Petitioners an activity the District itself lacks authority to undertake. And even if the District did have authority to regulate cargo carriers, any attempt to delegate that authority to Petitioners would run afoul of due process and the non-delegation doctrine. (See, e.g., *Carter v. Carter Coal Co*, (1936) 298 U.S. 238 (invalidating qualified legislative delegation of authority to private parties); *Assn. of Am. Railroads v. Dept. of Transp.* (D.C. Cir. 2016) 821 F. 3d 19 (invalidating certain delegations of authority to Amtrak based on due process concerns related to allowing Amtrak to effectively regulate or oversee a competitor in the marketplace).)

The District does not contest that it lacks authority to regulate cargo carriers. While it may prefer an emissions inventory containing cargo carrier data, the District cannot compel refineries to do what it lacks authority to do itself, at the risk of enforcement for failing to provide sufficiently accurate guesstimates. The cargo carrier provisions of Rule 12-15 are preempted and void. (*Am. Fed'n of Labor v. Unemployment Insurance Appeals Bd.* (1996) 13 Cal.4th 1017, 1042; *County of San Diego*, 166 Cal.App.4th 501.)

IV. CONCLUSION

For all of the foregoing reasons, this Court should grant the Petition and issue a writ of mandate finding Rule 12-15 preempted by state and federal law and requiring the District to: (i) vacate and set aside the Initial Study/Negative Declarations for Rules 12-15 and 9-14; (ii) comply with CEQA and H&S Code requirements in any future Refinery Project rulemaking; and (iii) vacate and set aside Rule 12-15.

Dated: April 11, 2017

Respectfully submitted,

BEVERIDGE & DIAMOND, P.C.

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WESTERN STATES PETROLEUM ASSOCIATION; VALERO REFINING COMPANY—CALIFORNIA, TESORO REFINING & MARKETING COMPANY, LLC, AND PHILLIPS 66 COMPANY

PROOF OF SERVICE

I, the undersigned, declare that I am employed in the County of San Francisco; I am over the age of eighteen years and not a party to the within entitled action; my business address is Beveridge & Diamond, P.C., 456 Montgomery Street, Suite 1800, San Francisco, CA 94104-1251.

On April 11, 2017, I served the following document(s): **PETITIONERS' REPLY BRIEF IN SUPPORT OF PETITION FOR WRIT OF MANDATE** on the interested party(ies) in this action.

Adan Schwartz
Senior Assistant Counsel
Bay Area Air Quality Management District
939 Ellis Street
San Francisco, CA 94109
E-mail: aschwartz@baaqmd.gov

The documents were served by the following means:

☒ BY ELECTRONIC TRANSMISSION: Based on an agreement of the parties to accept service by electronic transmission, I caused the documents to be sent to the person at the electronic notification address set forth above.

I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct.

DATED: April 11, 2017

BY: Robin Onaka
ROBIN ONAKA

From:	Tiffany Yu-Lee <yu_tiffany@hotmail.com>
Sent:	Monday, May 8, 2017 8:19 AM
To:	Victor Douglas
Subject:	Your Draft Environmental Impact Report for Rule 12-16 and Rule 11-18

Dear Mr. Douglas,

My name is Tiffany Yu. I am a resident of the city of Hercules. I have the following comments to your Draft Environmental Impact Report for Rule 12-16 and Rule 11-18.

1.4.11 – Page 1-7

The Air Quality setting describes "The State 8-hour standard was exceeded on 12 days in 2015 in the Air District; most frequently in the Eastern District (Livermore, Patterson Pass, and San Ramon). The federal 8-hour standard was exceeded on 12 days in 2015." It is not clear if the exceedance of the 12 days for State standards is the same for the Federal 8-hour standard exceedance. Are these the same days and also are these all in the Eastern District? How is 12-16 going to improve the Eastern District?

Table 3.2-2

The data shows the Bay Area Pollution Summary – 2015. Why is most of the data for Richmond, Crockett, and Martinez not shown? If you are focusing on Refineries, these are the cities that are close to them. I would like to know this data as I live between Richmond and Crockett.

I appreciate your consideration of my comments. Please contact me at yu_tiffany@hotmail.com.

Tiffany Yu Yu_tiffany@hotmail.com

May 7, 2017

Mr. Victor Douglas
BAAQMD
375 Beale Street, Suite 600
San Francisco, CA 94105

Dear Mr. Douglas,

I have questions about the Draft EIR data tables used to demonstrate and analyze of the existing environmental setting in the Bay Area.

Question #1:
In table 3.2-2, Bay Area Air Pollution Summary – 2015, why is it missing or lacking data pertaining to Ozone, CO, NO2, PM10, and PM2.5 for the cities of Richmond, Martinez, and Crocket? Is this data table incomplete? Is it a coincidence that these cities have refineries in their boundaries?

Question #2:
The language regarding Rule 12-16 states, "Presuming continuing increases in gasoline consumption results in unreasonable levels of speculation. For example, it is impossible for the Air District to predict the exact level of gasoline consumption in 2018 and how that would relate to Bay Area refinery capacity and how the market might react if production at Bay Area refineries were constrained by Rule 12-16. Therefore, the Air District is assuming, based on historical data the potential GHG emission impacts from the proposed project are concluded to be less than significant." Does it really require unreasonable levels of speculation? Why didn't the researchers perform their due diligence to obtaining the information? Couldn't they have perhaps referenced the experts (i.e. the industry itself)? The statement, "The Air District is assuming" – is that a blatant demonstration of bias in a document that should be objective? Isn't that a dangerous assumption for a regulation that could have significant impact on the Bay Area and our global environment?

Thank you for your consideration regarding my questions.

Respectfully,

Steven L. Ardito

WSPA
Western States Petroleum Association

Western States Petroleum Association
Credible Solutions • Responsive Service • Since 1907

Bob Brown
Director, Bay Area Region

May 8, 2017

Mr. Victor Douglas via email at: vdouglas@baaqmd.gov
Principal Air Quality Specialist
Bay Area Air Quality Management District
375 Beale Street, Suite 600
San Francisco, CA 94105

Re: Comments of the Western States Petroleum Association on Proposed Rule 12-16, and Draft Environmental Impact Report for Proposed Rules 11-18 and 12-16

Dear Mr. Douglas:

The Western States Petroleum Association (WSPA) is a non-profit trade association representing twenty-six companies that explore for, produce, refine, transport and market petroleum, petroleum products, natural gas and other energy supplies in California, Arizona, Nevada, Oregon, and Washington. Our members in the Bay Area have operations and facilities regulated by the Bay Area Air Quality Management District (District).

WSPA has significant concerns with regard to the District's proposed Regulation 12, Rule 16 (Rule 12-16), and the Draft Environmental Impact Report (DEIR) for Rule 11-18 and Rule 12-16, as described more fully in Attachments A, B, and C. WSPA understands that the District intends to vote only the adoption of Rule 12-16 at the end of May, and so our legal comments are focused on Rule 12-16 only. However, we are addressing the CEQA aspects of both Rule 12-16 *and* Rule 11-18, because the District's DEIR covers both rules.

WSPA appreciates the BAAQMD's consideration of our comments and we look forward to your responses. If you have any questions, please contact me at this office or Kevin Buchan at (925) 266-4083 or email kevin@wspa.org.

Sincerely,

Robert Brown

cc: Kevin Buchan, WSPA

Enclosure: WSPA Comments on Proposed Rule 12-16 (Attachment A), and DEIR for Proposed Rules 12-16 and 11-18 (Attachments B and C)

1320 Willow Pass Road, Suite 600, Concord, California 94520
(925) 266-4082 ▪ Cell: (925) 708-8679
bbrown@wspa.org ▪ www.wspa.org

Attachment A: WSPA Legal Comments on Proposed Rule 12-16

As the District is aware, WSPA submitted comments on the District's Project Description for Rule 12-16 on September 9, 2016, and on the District's Proposed Draft Rule 12-16 on December 2, 2016. WSPA continues to have significant concerns with the conceptual goal of Rule 12-16 and with the practical implementation of the rule's provisions. In general, WSPA agrees with District Staff's assessment that Rule 12-16 would not withstand judicial scrutiny. Proposed Rule 12-16 is inconsistent with existing federal and state air programs, would not be in harmony with the state cap and trade program for greenhouse gas emissions, arbitrarily limits specific refinery emissions to levels that are not necessary to protect local communities, and is beyond the District's statutory authority.

WSPA has submitted multiple letters and sets of comments to the District discussing its concerns over the legality of imposing numeric caps on emissions of GHGs, PM_{10}, $PM_{2.5}$, NO_x, and SO_2 from petroleum refineries. WSPA summarizes its concerns here, and incorporates by reference its past comment letters on Rule 12-16.[1]

The Board Cannot Adopt Rule 12-16 Without Making the Six Statutory Findings Required under the California Health and Safety Code

Prior to adopting a new or amended rule, the District must make six statutory findings: necessity; authority; clarity; consistency; non-duplication; and reference. Cal. Health & Safety Code § 40727. The Staff Report to Rule 12-16 was prepared "[a]t the direction of the Board … to provide an assessment of the rule's consistency with the Air District's statutory authority." Staff Report, at 5. The Staff Report fails to make these required findings; in fact, it cannot, because District Staff have concluded that adoption of Rule 12-16 would likely be beyond the Air District's authority and/or arbitrary and capricious. *See* Staff Report, at 39. Assuming that the Board is considering Rule 12-16 for adoption, the Board cannot adopt proposed Rule 12-16 without first demonstrating that the rule is within the District's authority, and providing an opportunity for public review and comment on that analysis. *See id.* § 40727.2(a) & (i).

Numeric Emissions Caps are Not Necessary

The numeric emissions caps under proposed Rule 12-16 are not necessary to protect public health or to address an existing air quality concern in the Bay Area. Emissions of GHGs, PM_{10}, $PM_{2.5}$, NO_x, and SO_2 are already extensively regulated at the federal, state, and local level. As the Staff Report explains, these rules apply standards "that ensure emissions are effectively controlled." Staff Report, at 13. Further, the broad range of air quality regulations that have been adopted by the District, California Air Resources Board (CARB), and the U.S. Environmental Protection Agency (EPA) were designed to ensure that emissions decrease over time and air quality improves. And indeed, existing ambient monitoring data and emissions inventories demonstrate just that: there have been consistent decreases in emissions and

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[1] WSPA Comment Letter on Proposed Reg. 6-5, 8-18, 9-14, 11-10, 12-15, and 12-16 (Nov. 23, 2015); Marne S. Sussman (Pillsbury Winthrop Shaw Pittman LLP), letter to Honorable Chair Mar, and Members of the Board of Directors, Bay Area Air Quality Management District, "Re: Legal Issues Pertaining to Refinery Emission Cap Option for Proposed Regulation 12-16" (July 19, 2016); WSPA Comment Letter on Draft Project Description for Regulation 12, Rule 16 and Regulation 11, Rule 18 (September 9, 2016); WSPA Comment Letter on Proposed Reg. 12-16 and 11-18 (Nov. 29, 2016).

improvement in air quality in the Bay Area. *See, e.g.*, Staff Report, at 14 ("mass emissions generally have been substantially reduced over the past several decades").

Proposed Rule 12-16 does not address any *current* emissions problem. Rather, it is rooted in the *possibility* that refinery emissions will increase in the future based on an assumption that changes in crude oil sources (from traditional sources to heavier sources requiring more intensive processing) will affect refinery emissions. *See* Staff Report, at 9-10 ("The intent of Rule 12-16 is to discourage or prevent refineries in the Bay Area from making changes that would lead to increases in emissions of certain pollutants"). WSPA and its members have repeatedly pointed out in prior comment letters that the possibility that new sources of crude oil will result in increased emissions is not supported by the facts, because, as the Staff Report briefly mentions, each refinery is designed to process a certain range of crude oil feedstocks, and its emissions from these operations are limited by the terms of its permit. *See* Staff Report, at 8-9. Any physical changes made to refinery operations to accommodate a different crude feedstock would already trigger permitting requirements and new emissions limits under the District's existing New Source Review (NSR) rules.[2] Thus, increased emissions stemming from operational changes at a facility would already be within the District's permitting authority. The hypothesis that refinery emissions may increase in the future based on changes in crude slate therefore does not constitute a "need" for numeric emissions caps today, given the District's existing regulatory authority in this area.

Furthermore, the Board cannot legally adopt Rule 12-16 without supporting the need for selectively targeting petroleum refineries. WSPA agrees with the assessment in the Staff Report that the imposition of numeric emissions caps on petroleum refineries would effectively create "a different set of permitting rules" for refineries than other sources in the Bay Area "by limiting pollutants from one Bay Area industrial sector through a mechanism unique to that industry and [that is] unlike the mechanism for all other industrial sectors." Staff Report, at 37. Imposing a different regulatory scheme on refineries is not currently justified in either law or air quality science.

Proposed Rule 12-16 Would Conflict with Existing Local, State, and Federal Air Programs and Policies

Proposed Rule 12-16 is likely to restrict refinery emissions to levels that are lower than those authorized under the refineries' current operating permits. These permits were obtained in accordance with the District's existing regulatory program (the NSR program), following detailed technical analyses by the District of refinery operations and emissions data; by law, these permits incorporate emissions limits and control requirements that represent the most stringent of all existing regulatory requirements, within thresholds determined by District Staff to be protective of public health.

Proposed Rule 12-16 would establish a new emissions cap, not based on available technology or public health thresholds, but rather solely on historical emissions. This approach has no basis in science. Refineries have vested rights in operating consistent with the emissions levels in their legally obtained permits, and generally rely on being able to operate up to their permitted potential to emit if needed. Rule 12-16 would arbitrarily re-set those authorized limits, in direct conflict with the District's current permitting rules and policies, without any showing of necessity (as described above).

In addition, the Staff Report explains that, if adopted, the emissions limits shown for each pollutant in Rule § 12-16-300 would need to be adjusted over time for various reasons, including, for example, as

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[2] *See* WSPA Comment Letter on Proposed Reg. 6-5, 8-18, 9-14, 11-10, 12-15, and 12-16, at pages 7-9 (Nov. 23, 2015); WSPA Comment Letter on Proposed Reg. 9-14 and 12-15, pages 9-11 (Feb. 22, 2016).

emissions measurement methods are improved, new information on criteria pollutants becomes available, or new regulations are adopted. Staff Report, at 23. However, no adjustments to the emissions limits would be made to accommodate new projects permitted through the NSR process, or recent projects permitted through the NSR process but still under construction. While this was an "intended consequence" of CBE's concept, it is an arbitrary and unjustified limitation on the permitting of new refinery projects. Staff Report, at 23. The Staff Report fails to describe how this limitation is necessary or within the District's authority. More importantly, this would directly conflict with existing policies and programs for permitting new projects in the Bay Area. The Clean Air Act (CAA) requires that the District's permitting program allow emissions increases at a facility as long as emissions are offset by an equal or greater amount of reductions of the same pollutant(s) from a location within the region. Staff Report, at 37. As the Staff Report explains, "Rule 12-16 would, in effect, eliminate that option for refineries and would require all emission increases to be offset within the individual facility." Staff Report, at 23. Thus, Rule 12-16 would directly conflict with the intent of the federal CAA and the District's NSR program to provide facilities with the maximum operational flexibility possible, within the constraints of the overall emissions limits that EPA, the State, and the District have determined are necessary to protect health and the environment. It would also disincentive refineries from investing in improvements to refinery facilities and technology, which technology could be intended to ultimately reduce a refinery's emissions.

GHG Caps are Ineffective, Counterproductive, and Inconsistent with Current State Efforts

Rule 12-16 would impose an enforceable limit on a refinery's direct emissions of GHGs. WSPA remains opposed to the localized regulation of GHG emissions from existing Bay Area refinery operations by the District. GHG emissions contribute to a global, not local, challenge; the local GHG regulation of refineries in the Bay Area Air Quality District are likely to simply shift GHG emissions elsewhere in the State or nation.[3] This has been recognized by District staff, the District's Advisory Council, CARB, and the Intergovernmental Panel on Climate Change.[4] Furthermore, the potential for rulemaking at multiple levels of government can lead to duplication of effort; or, of even more concern, regulations that work at cross purposes and undermine the effectiveness and efficiency of regulatory programs. WSPA supports pragmatic, market-based approaches to meeting California's climate goals, and is therefore concerned that the District's proposed GHG caps would undermine and interfere with the comprehensive refinery GHG regulations that CARB is developing as part of its state-wide GHG reduction scheme.

Given the significant existing efforts at the State level to regulate GHGs, Rule 12-16 raises significant concerns with the "authority," "consistency," and "nonduplication" requirements under the Health & Safety Code. As the Staff Report acknowledges, GHGs are regulated under the federal CAA and the California Global Warming Solutions Act (AB 32). AB 32 requires CARB to develop a comprehensive approach that California will take to reduce GHG emissions to levels mandated by the Legislature. In 2016, the California Legislature approved SB 32, which extends California's GHG emissions targets through 2030, with an objective of achieving a 40% reduction in emissions as compared to 1990 levels.

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[3] Although local regulations may reduce Bay Area GHG emissions, there remains a real potential for these regulations to increase global GHG emissions, which would work at cross-purposes to California's climate goals. The five Bay Area refineries that are the target of these rules represent some of the most efficient, highly-regulated refineries in the world. Ordering these refineries to reduce GHG emissions may require them to pursue a variety of different options, including curtailing production operations (which would necessarily increase production elsewhere to meet the demand for the products these refineries create) to meet the proposed requirements. To the extent that these options simply result in more processing by refineries that are not local, they result in no reduction in global GHGs; indeed, they would likely increase overall GHG emissions, as non-California refineries increase production to offset the decreases in production from the Bay Area.

[4] *See* WSPA Comment Letter on Project Description for Reg. 12-16 and 11-18 (Sept. 9, 2016).

On January 20, 2017, CARB released its proposed "2017 Climate Change Scoping Plan Update" (the "Proposed Scoping Plan") – its fifth update to the Scoping Plan, which specifically implements the new targets imposed by SB 32.[5] CARB has announced numerous public hearings on the Proposed Scoping Plan to take place in 2017, and is currently engaged in extensive efforts to improve and finalize the Proposed Scoping Plan and amendments to CARB's current GHG regulations. The cornerstone of the Proposed Scoping Plan is California's Cap-and-Trade Program, which is a comprehensive, economy-wide program to reduce GHG emissions in California.

In addition to AB 32 and SB 32, AB 197 compels CARB to prioritize "[e]mission reduction rules and regulations that result in direct emission reductions at large stationary sources of greenhouse gas emissions." Cal. H&S Code § 38562.5. Again, the Proposed Scoping Plan addresses these obligations, imposing "prescriptive regulations for refineries that would reduce greenhouse gases" and other air emissions, and in particular targeting a "20 percent reduction in greenhouse gas emissions from the refinery sector." Proposed Scoping Plan at ES3, ES5. The Legislature's decision to authorize CARB – and not the District – to seek these direct GHG emissions reductions continues its longstanding strategy of harmonizing GHG reductions at the *state* level, not within individual air districts.[6]

Even assuming the District had the authority to implement Rule 12-16, at best, that rule would merely duplicate the program developed by CARB, in violation of the "nonduplication" requirement. At worst, Rule 12-16 has the potential to interfere with CARB's efforts to implement its own regulations in a reasoned and effective manner, in violation of the "consistency" requirement. CARB is not planning to adopt refinery-focused GHG measures until at least late June, 2017. WSPA is concerned that the District's decision to proceed with GHG emissions caps at this time – before CARB itself has evaluated the available options and determined the most appropriate course of action – will instead create a duplicative, potentially inconsistent, and unnecessary regulatory scheme, and interfere with an orderly implementation of the Proposed Scoping Plan.

Further, refineries already are extensively regulated for GHG emissions. They are subject to California's Cap-and-Trade program; they must comply with CARB's Low Carbon Fuel Standard (which already regulates the carbon intensity of transportation fuels); and they will soon be subject to another statewide program aimed at further direct reductions in refinery GHG emissions once CARB determines the appropriate course of action. Given CARB's prior success in reducing GHG emissions across California, and the Legislature's express grant of authority to CARB to regulate in this area, the District's efforts are unnecessary, disruptive, and will impose a layer of burdensome bureaucracy that has little or no environmental benefit.

Rule 12-16 is Not Within the District's Authority to Adopt

In proposing a new rule or regulation, H&SC § 40001 requires that the District "determine that there is a problem that the proposed rule or regulation will alleviate and that the rule or regulation will promote the attainment or maintenance of state or federal ambient air quality standards[.]" *Id.* § 40001(c). As discussed above, the District has not identified an air quality problem that would justify the numeric emissions caps in Rule 12-16, nor has the District demonstrated that Rule 12-16 would promote the attainment or maintenance of the NAAQS. This is because Rule 12-16 addresses a problem that *may*

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[5] *See* CARB, 2017 Climate Change Scoping Plan Update (Jan. 20, 2017), *available at* https://www.arb.ca.gov/cc/scopingplan/2030sp_pp_final.pdf

[6] While CARB may elect "to partner with California's local air districts," it has yet to determine whether to do so and is currently considering a range of possibilities.

occur; the District does not have the authority under the federal Clean Air Act to adopt regulations that do not address existing air quality issues.

Emissions Caps Based on Historical Emissions are Technically Problematic

WPSA incorporates by reference its discussion of this issue in WSPA's comment letter dated November 29, 2016.

Attachment B: WSPA Legal Comments on the DEIR for Rules 11-18 and 12-16

The California Environmental Quality Act ("CEQA") requires the District to consider the whole of a Project, including both direct and indirect environmental impacts from the entire project. Public Resources Code, § 21000 *et seq*. CEQA is further implemented by the CEQA Guidelines, Title 14, California Code of Regulations, § 15000 *et seq.* Proposed Rules 12-16 and 11-18 are part of a suite of regulations identified by the District as the Petroleum Refinery Emissions Reduction Strategy (Refinery Strategy). The combined suite of regulations is part of a larger plan to reduce purported refinery emissions in the Bay Area by at least 20% within just a few years.

WSPA has previously provided CEQA comments for proposed Rules 12-16 and 11-18, which comments are incorporated by reference here.[7] The following comments pertain to the District's March 2017 Draft Environmental Impact Report (DEIR) for proposed Rules 12-16 and 11-18. The various substantive issues WSPA raises below clearly show that the District has not complied with CEQA in preparing and analyzing Rules 12-16 and 11-18.

CEQA prohibits "segmenting" projects to create the appearance of a lesser degree of impact. Agencies must consider and evaluate "the whole of an action" when they adopt new rules and cannot chop up actions into smaller components to minimize impacts or evade review. Cal. Code Regs. tit. 14, § 15378(a). To date, the District has consistently segmented and limited its analyses to individual rules, excluding consideration of the rules it has recently adopted as part of the "Refinery Strategy" (Rules 6-5, 8-18, 11-10, 12-15 and 9-14) and the rules currently under development (Rule 13-1) pursuant to this same strategy. WSPA has previously commented upon the segmenting issue, and WSPA incorporates those comments by reference here.[8] However, the March 2017 DEIR for Rules 12-16 and 11-18 attempts to review two regulations within the same DEIR, with confusing results. The District attempts to review, in its words, two Projects (asserting that each Rule is a separate project) in one EIR. The project description is therefore confusing and does not properly inform the public what project is being considered. The District needs to provide the citation in CEQA that allows for two separate projects to be reviewed in an EIR that is not, for example, a programmatic EIR.

The District cannot piecemeal the analysis of environmental impacts from the Petroleum Refinery Emissions Reduction Strategy project that are clearly derived to work toward the common goal of a 20% emissions reduction target. Furthermore, the District must ensure that its analysis and findings are based upon credible substantive evidence, that a reasonable range of alternatives are considered, that the project decisions meet the purpose and need, significant impacts are avoided or mitigated and that the whole of the action is identified and analyzed. The District has failed to meet the requirements for preparing an EIR that properly informs the decision-maker and the public.

The District should have prepared an EIR for the Refinery Strategy project. "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 the informational document that must be considered by the public agency prior to its approval or disapproval of the project. Without a true analysis of the whole

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[7] *See* references in footnote 1.

[8] *See* references in footnote 1; *see also* WSPA Comment Letter on Proposed Reg. 9-14 and 12-15 (Feb. 22, 2016); WSPA Comment Letter on Proposed Reg. 12-15 (Apr. 8, 2016); WSPA Comment Letter on Proposed Reg 13-1 (Apr. 21, 2017).

project, it is impossible to quantify and understand the magnitude of the impact the adopted and proposed changes will have on the environment.

The following comments highlight WSPA's substantive issues with the District's analysis in the DEIR. Please also see Attachment C for WSPA's technical comments with the District's DEIR:

Page 1-1, Executive Summary, first paragraph.

The DEIR states: "*Though refinery emissions have declined over time, it is possible that, as refinery operations change in the future, emissions of these pollutants could increase.*"

Comment: It is more likely that emissions will continue to decline. Existing permit conditions, regulations and plans are in place that limit emissions and allow for offsets. Furthermore, any new projects that might increase emissions would be regulated under the District's existing NSR program and would require the installation of controls and compliance with strict emissions limits.

Pages 1-1 and 1-2.

(a) **Comment**: The District states that the development of these rules was included as Action Item 4 in the Air District's Work Plan for Action Items Related to Accidental Releases from Industrial Facilities. This same Action Item is, according to the District, the genesis for the District's Petroleum Refinery Emissions Reduction Strategy (Refinery Project), which is a project to reduce refinery emissions by 20%. The Staff Report also makes clear that the District believes that the suite of rules (the Refinery Project) are bundled to achieve the common goal of a 20% reduction. WSPA and its members have filed multiple lawsuits challenging the District's adoption of various aspects of the Refinery Project as violating CEQA in light of the District's failure to develop a comprehensive EIR for the entire Refinery Project.[9] Because Rules 12-16 and 11-18 are part of the same Project, the impacts must be considered together with the impacts from the other Refinery Project rules.

As the cited pages describe, the District is proposing Rule 11-18 as an alternative to Rule 12-16. However, the District's Staff Report concludes that Rule 12-16 is likely contrary to law, arbitrary and capricious, and will not improve air quality. *See* Staff Report, at 36 – 37. The District states that there is no factual support for selectively targeting the petroleum refinery industry for emissions caps, that the rule would conflict with existing permits and regulations in place that address the issue and that Rule 12-16 is unlikely to improve air quality in refinery communities. *See* Staff Report, at 36-37. As described in Attachment A, WSPA agrees with the District's assessment of Rule 12-16. However, to the extent that the Board relies on the DEIR for purposes of adopting or rejecting Rule 12-16, the DEIR needs to articulate the purpose and need/objectives for Rule 12-16 and then provide a more thorough explanation as to why the Rule should not be adopted given its failure to meet the purpose and need.

(b) **Comment**: The Staff Report explains that the District does not believe that Rule 12-16 will be effective and will not improve air quality in refinery communities. *See* Staff Report, at 1, 14. The DEIR explains that for the No Project alternative for Rule 12-16, the control of the identified emissions would

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[9] Western States Petroleum Association , et al. v Bay Area Air Quality Management District (filed in Contra Costa County Superior Court, case number N16-0963); Valero Refining Company—California, Tesoro Refining & Marketing Company, LLC, and Phillips 66 Company v. Bay Area Air Quality Management District (filed in Contra Costa Superior Court, case number N16-0095).

continue to be addressed by the District's current programs, including "the rules and rule amendments of the Refinery Strategy". *See* DEIR, at 1-15 (Section 1.5.2). The District states that the primary differences between Rule 12-16 and the No Project alternative is that the collection of identified measures that the District would continue to use if Rule 12-16 is not adopted "would not only prevent the increase of climate and combustion criteria pollutants, but would result in substantial decreases of these pollutants over time" whereas Rule 12-16 does not require emissions reductions.

In order for the Board to adopt Rule 12-16, the District would need to articulate why Rule 12-16 is necessary, what the actual purpose and need for the project is and why this proposed regulation (that conflicts with other regulatory procedures and will not improve air quality in refinery communities) is warranted.

Page 1-5, Section 1.3.3, Project Objectives.

Comments: Regarding the objectives of Rule 11-18 (Toxic Risk Reduction Rule), how does the District intend to define, identify and quantify "overburdened communities" as stated in the second bullet point? There is no discussion of this issue in the DEIR. In addition, regarding the Health Risk Assessment objectives (to "provide transparency and clarity to the process" and "provide the public opportunity to comment"), the District must articulate what Rule 11-18 would provide that is not already required by the public rulemaking process and CEQA.

The objectives of Rule 12-16 also are captured in existing permits and regulations such as the New Source Review requirements. The objectives conflict with existing regulations and programs such as Cap and Trade and offsets. The District needs to explain how Rule 12-16 will not conflict with or violate existing permits, regulations, and statewide programs.

Page 1-10, Section 1.4.2.2, Greenhouse Gas Emissions Impacts.

Comment: The analysis in the DEIR states that the proposed refinery limitations in Rule 12-16 would not be expected to conflict with CARB's Cap and Trade Program because covered entities could continue to use GHG credits for compliance purposes and that GHG increases could continue to be offset. However, under Rule 12-16, a refinery "*shall not emit greenhouse gas emissions that exceed the emissions limits shown in Table 12-16-301*." *See also* Staff Report at 37-38 ("*…there is a significant argument that a fixed numeric cap for criteria pollutants conflicts with these federal and state provisions that allow facilities to increase emissions if certain conditions are met. It may be difficult to legally justify the necessity for such a measure…")*

The District needs to clarify how the emissions cap listed in Rule § 12-16-301 allows refineries to use GHG credits for compliance purposes, as asserted on page 1-10 of the DEIR.

Page 1-14, Section 1.5.1, Project Alternatives for Proposed Rule 11-18.

The DEIR states that portions of 11-18 could be implemented under the Air District's AB 2588 – Air Toxics "Hot Spots" Program. The District states that with Alternative 1.2, the District would establish risk action levels at 25/M for cancer risk and 2.5 for hazard indices.

Comment: The District needs to ensure that Alternative 1.2 does not conflict with other District regulations and is feasible.

Page 2-7, Section 2.4.2, Project Description.

Comment: The project description is confusing. The DEIR states that District staff does not recommend adoption of Rule 12-16 and instead recommends adoption of Rule 11-18. *See* DEIR, at 2-1.

Furthermore, Section 4.0 of the DEIR contains a discussion of project alternatives. Tables 4-2a on page 4-18 and 4-2b on page 4-19 have a column identified as the "proposed project" but no clear "proposed project" has been identified. The District appears to be putting forth two proposed projects in the same DEIR. The District is actually proposing alternatives for the decision maker: Alternative 1 is to adopt Rule 12-16 (or variations of Rule 12-16); Alternative 2 is to adopt Rule 11-18 (or variations of Rule 11-18); Alternative 3 is to adopt both; and Alternative 4 is to adopt Rule 11-18 together with Rule 13-1, which rule is still under development. Note that neither the alternatives discussion or Tables 4-2a or 4-2b include the alternative to adopt Rules 12-16 and 11-18 together, yet there is discussion of this alternative in the document.

The situation is even more confusing since the decision maker and the public are to review the information to assess what alternative best fits the purpose and need of the project; but here there are, as the District asserts, two projects in the DEIR. The DEIR is flawed because it confuses "alternatives" with "project" and does not provide for a clear purpose and need for the actual proposed project; as noted above, the project is actually the Refinery Project.

Page 2-8, Table 2.4-1, Implementation Phases.

Comment: Appears to be an error for diesel IC Engines under the HRA column. What is the correct range of years so the correct information can be reviewed?

Page 3.1-4, Section 3.1.5, Cumulative Impacts.

Comment: The District needs to articulate how this DEIR evaluates the cumulative environmental impacts associated with the planning and implementation of other air quality rules recently adopted and reasonably foreseeable similar regulations (Refinery Project Rules 6-5, 11-10, 8-18, 12-15, and 9-14), proposed regulations (Rule 13-1), and any planned regulations or amendments to regulation (Rules 2-1 and 2-2, for example). Furthermore, the DEIR is flawed because it identifies Rule 13-1 as an alternative but does not perform a cumulative impact analysis with any of the Refinery Project rules, or even Rule 11-18, which is included as an Alternative in this DEIR.

Page 3.2-9: TABLE 3.2-4, "2011 Air Emission Inventory – Annual Average".

The footnote to Table 3.2-4 states that the source of the information is from "Bay Area Emission Inventory Summary Report: Criteria Air Pollutants (BAAQMD, 2014)". The following paragraph then cites a BAAQMD 2017 statement: "*Approximately 84 percent of NOx emissions in the Bay Area are produced by the combustion of fuels. Mobile sources of NOx include motor vehicles, aircraft, trains, ships, recreation boats, industrial and construction equipment, farm equipment, off-road recreational vehicles, and other equipment. NOx and VOC emissions have been reduced for both stationary and mobile sources. Stationary sources of VOC and NOx have been substantially reduced due to stringent District regulations (BAAQMD, 2017).*"

Comment: The District should use more recent data for this EIR than the 2011 emission inventory. The District needs to state why it is using 2011 annual emissions data for a 2014 Inventory Summary Report in a 2017 DEIR. Furthermore, the District follows Table 3.2-4 with a discussion of how the air has improved and cites percentages. However, the source of that information is not provided and needs to be provided. The public and the decision-maker should be provided with the most current data to properly assess the impacts and mitigation.

Page 3.2-17 (top of the page) and Page 3.2-22, Section 3.2.3.2, Operational Emissions.

Comment: Rules 12-16 and 11-18 are part of the Refinery Project, which project is designed to reduce emissions at refineries by 20%. The example on the pages given above, that one control measure may result in increasing criteria pollutant emissions and the opportunity to offset, applies to the Refinery Project. The Refinery Project's suite of regulations must be reviewed in a cumulative and comprehensive manner in order to determine whether there is a significant impact upon the environment and to properly inform the decision maker and public. *See* CEQA Guidelines § 15130. The Refinery Project shares a common goal and identifies regulations that will be amended and/or created in order to achieve that goal. Rules 12-16 and 11-18 must be analyzed for cumulative impacts, not just between the two, but together with the recently adopted Refinery Project rules (6-5, 11-10, 8-18, 12-15, and 9-14), proposed regulations (Rule 13-1) and any planned regulations or amendments to regulation (Rules 2-1 and 2-2, for example).

An example of how the Refinery Project's suite of regulations could cumulatively negatively impact the environment, and therefore must be cumulatively analyzed, is exhibited on DEIR page 3.2-37. The language states that "*As summarized in Tables 3.2-19 and 3.2-20, Rule 11-18 and Rule 12-16, respectively, could produce substantial construction air quality impacts if larger types of air pollution control equipment are installed. This impact would be compounded if more than one piece of air pollution control equipment is installed on the same day or both rules are adopted. Again, because Rule 11-18 would potentially regulate a substantially greater number of industrial sources, it would create greater air quality impacts than Rule 12-16.*"

Another example is shown on 3.2-39: "***Conclusion:*** *Based on the construction emissions shown for each rule in Tables 3.2-19 and 3.2-20, it is concluded that NOx construction air quality impacts may be significant under either rule scenario* <u>*and potentially more significant if both rules are adopted*</u>*.*" (emphasis added). The District also needs to address the significance compared with the other Refinery Project rules.

Finally, the analysis on page 3.2-53 in section 3.2.6.1.1 only refers to construction impacts and only to the two rules in the document (Rules 12-16 and 11-18). There are construction and operational impacts that should be analyzed with the suite of Refinery Project rules which may be considerable when analyzed cumulatively.

The District needs to properly analyze the cumulative impacts of these rules along with the other Refinery Project rules and inform the decision maker and the public regarding impacts and proposed mitigation measures. This comment also applies throughout the DEIR, for example to sections 3.3 (Greenhouse Gas emissions), section 3.4 (hazardous materials), and section 3.5 (hydrology and water quality).

Section 3.2.3, Significance Criteria.

Comment: With respect to Rule 11-18, the DEIR does not address any significance criteria for toxic air contaminants (i.e., cancer risk, acute and chronic health indices). It is not possible to properly determine impacts if there are no significance criteria. Section 3.2.6.2 further states that "In addition, reductions in TAC emissions would be expected due to implementation of Rule 11-18, but those emission reductions and the related health risk benefits cannot be estimated at this time." Rule 11-18 is not properly analyzed in this DEIR.

Page 3.2-31, Section 3.2.4.1.2.

The DEIR states: "*It is assumed that the proposed project has the potential to result in the construction of up to three to five WGS units under Rule 11-18 or three to five units under Rule 12-16.*"

Comment: What is the basis for this assumption? Additionally, since Rule 11-18 would apply to many industries and facilities, why is the assumption the same for Rule 11-18 as for Rule 12-16, which only applies to five refineries and three ancillary facilities?

Page 3.3-15, Section 3.3.4.

The DIER states: "*Due to the complexity of conditions and interactions affecting global climate change, it is not possible to predict the specific impact, if any, attributable to GHG emissions associated with a single project. Although the geographic scope of this GHG emissions impact analysis in this EIR is the State of California, it is the cumulative effects of all global GHG emissions sources that have the potential result in global climate change. For this reason, GHG emission impacts contributing to global climate change are considered a cumulative impact analysis rather than a project-specific analysis.*"

Comment: The District is not analyzing how the Refinery Project's suite of regulations impacts the environment regarding GHG emission impacts contributing to global climate change, which "are considered a cumulative impact analysis rather than a project-specific analysis." The DEIR fails to comply with CEQA by only attempting to cumulatively consider these two regulations. CEQA Guidelines § 15355 defines cumulative impacts as: "two or more individual effects which, when considered together, are considerable or which compound or increase other environmental impacts.

(a) The individual effects may be changes resulting from a single project or a number of separate projects.
(b) 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 reasonable foreseeable probable future projects. Cumulative impacts can result from individually minor but collectively significant projects taking place over time."

Rules 12-16 and 11-18 are both part of the Refinery Emissions Reduction Strategy, they are closely related to the "suite of regulations" identified by the District, and they have the same common goal to reduce refinery emissions. Therefore, a cumulative analysis is necessary that includes the recently adopted Refinery Project rules (6-5, 11-10, 8-18, 12-15, and 9-14), proposed regulations (13-1), and any planned regulations or amendments to regulation (2-1 and 2-2, for example). *See* CEQA Guidelines § 15130.

Comment: The GHG impact analysis is inadequate because it does not evaluate the impact Rule 12-16 will have on global GHG emissions. The DEIR maintains that "GHG emission impacts contributing to global climate change are considered a cumulative impact analysis rather than a project-specific analysis." DEIR, at 3.3-15. The DEIR must properly analyze impacts from GHG emissions in compliance with CEQA Guidelines § 15064.4.

In this regard, the DEIR has failed to address at least one way the Project may increase global GHGs: leakage. As recognized by the IPCC and CARB, and defined by the IPCC, leakage is the "phenomena whereby the reduction in emissions (relative to a baseline) in a jurisdiction/sector associated with the implementation of mitigation policy is offset to some degree by an increase outside the jurisdiction/sector through induced changes in consumption, production, prices, land use and/or trade across the jurisdictions/sectors. Leakage can occur at a number of levels, be it a project, state, province, nation, or world region."[10]

As discussed in the legal comments on Draft Rule 12-16 in Attachment A of this comment letter, California refineries are already extensively regulated. To the extent that Rule 12-16 imposes a cap and thereby restricts the ability of California refiners to meet demand, that demand will be made up by other refiners, therefore there would be no benefit on global GHG emissions. This impact is supported by substantial evidence. For example, at the October 19, 2016 BAAQMD Board of Directors meeting, the California Energy Commission gave a presentation entitled "California Refinery Overview and SF Bay Area Crude Oil Slate", which explained that following the February 2015 explosion at the ExxonMobil Torrance refinery's FCC, the decrease in southern California refinery production of gasoline was offset by Bay Area refinery gasoline production and a 10-fold increase in foreign imports.[11]

A mass GHG limit on Bay Area refineries, as proposed in Regulation 12-16, would also limit the ability for Bay Area refinery gasoline production to offset a supply shortage. Under Rule 12-16, supply shortages would result in more gasoline being produced outside of California and transported into California, which would in turn increase the GHG intensity of gasoline supply in California due to increased transportation needs. A similar and reasonably foreseeable situation can occur if unexpected and/or planned maintenance events at California refineries occur simultaneously among different refineries, which would also decrease gasoline production from California refineries. Should such an occurrence happen, the refineries that increase production to meet the shortfall may not be as efficient.

Page 3.3-26, Section 3.3.4.3, Potential Conflicts With State GHG Compliance Plans.

Comment: This is a carefully articulated and artificial finding. The District is basing its conclusion on historic data that the refineries have not exceeded the proposed Rules 12-16 emissions caps and, therefore, proposed 12-16 will not conflict with the existing State Cap and Trade program. At the outset, this assumption is faulty; the current emissions caps are based on historic levels of production, which may or may not reflect future demand; furthermore, as discussed above in WSPA's legal comments, the emissions caps are designed to be adjusted downwards in the future in response to a number of factors, and may not be increased even in response to new projects or production at a refinery. Thus, it is entirely possible, if not probable, that the Rule 12-16 caps will at some point become more stringent than the Cap and Trade program would otherwise authorize. The District is not informing the public about how such a conflict would be handled. The District needs to specifically answer the following question: Can the refinery use Cap and Trade and other offset programs as they are legally authorized to obtain credits that place them legally under the cap even though they actually exceed the Rule 12-16 cap? California's ability to meet its GHG reduction limits under AB 32 and related regulatory mandates call for the use of such programs as Cap and Trade. Rule 12-16 separates the Bay Area refineries from the rest of the industries in California by prohibiting these few entities from participating in a legally approved statewide program to meet statewide goals. This is a conflict with existing plans and violates CEQA.

Page 3.5-16: Rule 12-16.

The DEIR states: "*If any refineries are shown to exceed the refinery-wide emissions limits for PM2.5, PM10, NOx or SO2, it is expected that refinery operators would install new, or modify their existing air pollution control equipment in order to reduce emissions as required by Regulation 12-16. Additional*

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[10] https://www.ipcc.ch/pdf/assessment-report/ar5/wg3/ipcc_wg3_ar5_annex-i.pdf
[11] https://www.eia.gov/todayinenergy/detail.php?id=23312

water demand and wastewater generation impacts are expected to result from the operation of several of the possible control technologies that would most likely be used including wet electrostatic precipitators (ESPs) and wet gas scrubbers (see Table 3.5-1).”

Comment: It is possible that the thresholds identified in Table 3.5-1 would be exceeded due to the required retrofits, and the analysis in the DEIR states there are many unknowns. What appears to be known is that Rules 11-18 and 12-16 together would exceed the threshold for water usage which is a significant impact for a regulation that the District does not support. Furthermore, the recommended mitigation measures are not expected to reduce the level of significance.

Page 3.5-23, Section 3.5.5.2.

The DEIR states: “*Therefore, the proposed project will remain significant after mitigation for water demand.”*

Comment: What does “proposed project” refer to in this sentence? Is the proposed project Rule 12-16, 11-18 or both? The District needs to identify the actual project. Furthermore, note that for both Rules 12-16 and 11-18, the recommended mitigation will not reduce the significant impact for water demand. The District must weigh and analyze the expected improvement by adopting the Rules against the significant impact on water demand even after mitigation.

Page 4-3, Section 4.1.

Comment: This section states that the alternatives are limited by the nature of the project. CEQA requires an analysis of a reasonable range of feasible alternatives to accomplish the purpose and need of the project. Here for example, the discussion in this section states that a portion of the proposed rules could be implemented under other existing or planned requirements/measures. The analysis does not identify what elements of the proposed rules could be handled by these other requirements or measures and when identified, may result in other feasible alternatives, significant impacts or appropriate mitigation. Such analysis may also question whether the remaining rule elements actually satisfy the objectives.

Page 4-5, Alternative 2.1, Regulation 12-16.

Comment: The District’s inclusion of the “Rules and rule amendments in the Refinery Strategy” in this section demonstrates the District’s understanding that the Refinery Strategy is a project under CEQA, in that the rules and amendments are designed for a common purpose. What the District fails to do, however, is to properly analyze the potential significant impacts from the cumulative actions of this suite of regulations.

Page 4-6, Alternative 2.1, Regulation 12-16.

The DEIR states: “*The primary differences between Rule 12-16 and the No Project Alternative (12-16) is that the collection of measures listed referenced above would not only prevent the increase of climate and combustion criteria pollutants, but would result in substantial decreases of these pollutants over time (the proposal does not require emissions reductions).”*

Comment: The District’s discussion makes it clear that Rule 12-16 is not needed. There are already regulations in place or more comprehensive planned regulations. If the District is to demonstrate the necessity of the proposed rule, it must articulate why the rule would improve air quality more than the current and other proposed regulations (see examples provided in Section 4.3.1.1, 4.3.1.2, and 4.3.1.3) or existing federal and state permit requirements, and why this additional air quality reduction merits creating a significant impact with water usage. The DEIR not only fails to make this demonstration, it affirms that such a demonstration cannot be made.

Page 4-7 Section 4.3.2, Alternative 2.2.

The DEIR states: "*…This alternative would consist of a combination of the environmental benefits and impacts of adopting and implementing proposed Rule 12-16 and draft Rule 13-1*."

Comment: The District should clarify whether Rule 12-16 is part of this alternative as stated in the first sentence or if this is a typographical error. If 12-16 is part of this alternative, the District should explain the impacts and the analysis in the alternative.

Page 4-13, Section 4.5.2.

Comment: The District discusses how the Rule 12-16 No Project alternative will not have a significant impact upon the environment if Rules 11-18 and 13-1 are adopted together, but does not discuss in the alternatives analysis the impact of Rules 11-18 and 13-1 being adopted together. The District needs to assess the cumulative impacts of the Rules 11-18 and 13-1 alternative, along with the other Refinery Project rules, to comply with CEQA.

Page 4-18, Section 4.8.2, Comparison of Alternatives.

Comment: The District concludes that combining Rule 11-18 and 13-1 is the preferred alternative. However, throughout this DEIR, the District reviews Rules 12-16, 11-18 and a combination of Rules 12-16 and 11-18. The District does not analyze the cumulative impacts of Rules 11-18 and 13-1 being implemented or any necessary mitigation measures. In fact, Rule 13-1 does not appear in Table 1-1 on page 1-18. The District fails to comply with CEQA by not properly analyzing the Alternative.

Attachment C: WPSA Technical Comments on the DEIR for Rules 11-18 & 12-16

Executive Summary

Greenhouse Gases (GHGs)

The cumulative impact associated with GHG emissions is dependent on global GHG. California refineries are more efficient than most other refineries, and Bay Area regulations which limit Bay Area refineries' production and shift production to less efficient refineries outside the Bay Area will increase global GHG even though the reduce GHG in the Bay Area.

Policies to address global fuel demand in the lowest GHG manner should instead favor production at the most efficient refineries. Capping emissions at the Bay Area refineries could easily inhibit the ability of the refineries to make changes needed to produce lower-carbon fuels, and GHGs associated with consumers' fuel use are far higher than the GHGs associated with the fuels' production at the refineries.

The DEIR includes no analysis of the extent to which the proposed regulations to reduce emissions from Bay Area refineries may result in increases in global GHG and the associated cumulative impacts, and needs to do so. The DEIR is inadequate because it was not "prepared with a sufficient degree of analysis to provide decision makers with information which enables them to make a decision which intelligently takes account of environmental consequences" (as required by 14 CCR 15151). WSPA made these same comments on the draft PEIR for the District's 2017 Clean Air Plan and the District did not respond to them, even though a response is required by 14 CCR 15088(a). Without such a cumulative impacts analysis, the DEIR also does not provide a "good-faith effort at full disclosure" as required by 14 CCR 15003(i).

Air Toxics

The stated goal behind Regulation 11-18 is to make it unacceptable for existing facilities to impact any location with an estimated potential for[12] a total 10-in-a-million lifetime cancer risk, despite the fact that the EIR for the District's 2017 Clean Air Plan identified that a new project increasing potential existing risk by less than 100-in-a-million is not "significant" under CEQA.[13] Under CEQA, this means that the District determined—"based to the extent possible on scientific and factual data"[14]—that increasing the potential for existing risk by less than 100-in-a-million is not a "substantial, or potentially substantial, adverse change".[15]

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[12] As identified in OEHHA's 2015 Risk Assessment Guidelines, "there is a great deal of uncertainty associated with the process of risk assessment....The assumptions used in these guidelines are designed to err on the side of health protection in order to avoid underestimation of risk to the public....Risk estimates generated by [a Health Risk Assessment] should not be interpreted as the expected rates in the exposed population but rather as estimate of potential f or disease, based on current knowledge and a number of assumptions." (pp. 1-5 and 1-6 of the "Guidance Manual for Preparation of Health Risk Assessments")

[13] BAAQMD, Final Program Environmental Impact Report for "Spare the Air – Cool the Climate" State Clearinghouse No. 2016062046, April 2017, Section 3.2.4.

[14] Per 14 CCR 15604(b). WSPA commented that the EIR for the Clean Air Plan did not include this basis and needed to, but the District did not respond to that comment (even though a response is required by 14 CCR 15088(a)).

[15] This is from the definition of "significant effect on the environment" at 14 CCR 15382.

Section 3.2.6.2 of the DEIR for Regulations 11-18 and 12-16 concludes that potential TAC emissions are "less than significant", but provides no evaluation of this. In fact, the section does not even provide significance criteria for TACs or state where to find such analysis in the DEIR, if it does exist. The lack of evaluation and the conclusions are inconsistent with the fact that the District currently requires projects with emissions of as little as 0.26 pounds per year of diesel exhaust PM to conduct a Health Risk Assessment to determine whether they are above or below 10-in-a-million risk thresholds [16]. In addition, the District's emissions calculations in Appendix B of the DEIR include scenarios with emissions of off-road diesel PM emissions exceeding ten times that amount (2.6 pounds) per day.[17]

The District identifies Regulation 11-18 as "address[ing] concerns about health risks to the refinery communities". WSPA believes that a far more productive way to address concerns would be for the District to provide context and consistency in their communications regarding the significance of these potential risks.

Detailed Comments

There is a statement in Section 3.2.1.4.1 of the DEIR that "many scientists believe that there are not 'safe' levels of exposure to carcinogens without some risk to causing cancer". The District does not provide a citation for the statement as required by 14 CCR § 15148. There is no practical means of measuring a zero-risk health impacts threshold, and this is not the same as saying that there are not 'safe' levels; such logic would lead one to believe that essentially nothing is safe. WSPA commented similarly on the draft PEIR for the District's 2017 Clean Air Plan and the District did not respond to it as required by 14 CCR 15088(a).

The second and third paragraphs in Section 3.2.1.2.4 of the "Environmental Setting" include two paragraphs of statements that are uncited and imply causality without any quantitative information on whether those correlations are causal. This is especially the case for the range of PM concentrations in the Bay Area that has been raised by multiple authors in peer-reviewed literature.[18]

WSPA raised this concern previously in our comments on the District's Clean Air Plan[19]. The District's response to our comments was, "*Our scientists review a wide range of documents....We are, of course, always happy to discuss data and uncertainties in analysis, taking in to account ways that particulate matter impacts may be overstated or underestimated*"[20] . Language reflecting this response does not appear to have been added to the Plan or provided in the Program EIR for the Plan.

The statement in Section 3.2.1.4.1 that "*the proportion of cancer deaths attributable to air pollution has not been estimated using epidemiological methods*" is misleading. An upper bound ("potential for") estimate of contracting cancer from air pollution has been estimated by the District, and the value is so

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[16] Per BAAQMD Regulation 2-5.

[17] The District's "FCCU with SCR" evaluation shows 4.12 lb PM_{10}/day from off-road diesel equipment. The District's other scenarios also show daily PM_{10} emissions from off-road diesel equipment far in excess of the District's annual 0.26 lb threshold.

[18] See, for example, articles in Special Issue on Air Pollution Health Risks, *Risk Analysis* **36(9)** (2016).

[19] B. Brown (Director, Bay Area Region, WSPA), letter to Ms. Christy Riviere (Senior Environmental Planner, BAAQMD) "Re: WSPA Comments on 2017 Draft Clean Air Plan/Regional Climate Protection Strategy", March 9, 2017.

[20] BAAQMD, "Response to Public Comments", Appendix B to the 2017 Clean Air Plan, p. 97.

low that it is too small to be detectable by epidemiological methods. District needs to reference the source for their assertions rather than just implying that the proportion is a complete unknown.

The statement in Section 3.2.1.4.1 about "*the estimated lifetime cancer risk for Bay Area residents....declined from 4,100 cases per million in 1990 to 690 cases per million people in 2014*" is inaccurate. OEHHA (which developed the guidance upon which Bay Area bases its assessments) has specifically stated that "*Risk estimates generated by [a Health Risk Assessment] should not be interpreted as the expected rates in the exposed population but rather as estimate of potential f or disease, based on current knowledge and a number of assumptions*" (pp. 1-5 and 1-6 of OEHHA's "Guidance Manual for Preparation of Health Risk Assessments").

Figure 3.2-12 identifies diesel PM as the predominant TAC of concern from the perspective of risk, but Table 3.2-5 provides no information regarding what monitoring data that estimate was derived from. We have not been able to locate the cited report "BAAQMD, 2016. Toxic Air Contaminant Air Monitoring Data for 2014", and request the BAAQMD make it publicly available.

Table 3.2-5 of the DEIR identifies the air toxic with the highest concentration as ethyl alcohol. It is not clear if the District is proposing to include ethyl alcohol in Rule 11-18. Currently, ethyl alcohol is not one of the Hazardous Air Pollutants (HAPs) identified by US EPA. It is not currently listed as a Toxic Air Contaminant (TAC) as defined in H&SC 39655(a) nor is listed in ARB regulations at 17 CCR 93000), and is not identified as a reportable substance in Appendix A of OEHHA's Guidance Manual for Preparation of Health Risk Assessments, and is not listed in BAAQMD's Regulation 2-5 for Toxic Air Contaminants.

The cumulative impacts analysis in Section 3.3.1 of the DEIR does not "*reflect the severity of impacts and their likelihood of occurrence*" as required by 14 CCR §15130(b), and needs to include available information. WSPA made this comment on the draft PEIR for the District's 2017 Clean Air Plan and the District did not respond to it as required by 14 CCR 15088(a).

Section 3.3.3 of the DEIR includes a paragraph that identifies a project level GHG threshold for stationary source projects of 10,000 metric tonnes of CO_2e, citing the District's 2010 CEQA Air Quality Guidelines. Those Guidelines identified a threshold of 10,000 metric tonnes of CO_2e per year of operational emissions. As identified on the District's CEQA webpage, the District was ordered to "*set aside the Thresholds and is no longer recommending that these Thresholds be used as a general measure of project's significant air quality impacts*".

Section 4.1 of the DEIR identifies the objectives for proposed rule 11-18 inaccurately. The objective is not to reduce exposure "*to the lowest levels achievable*"; if that were true, there wouldn't be any risk thresholds identified in the rule. The rule is written to reduce exposure from stationary sources to less than the risk thresholds identified in the rule, which are not based on any scientific or technical analysis of what level of "potential for risk" is safe or achievable.

The District's stated objective to "*ensure the facilities that impact the most sensitive and overburdened communities reduce their associated health risk in an efficient and expedited manner*" is misleading, given that all facilities in the air basin have some impact on regional air quality. Rule 11-18 identifies a level of impact that a facility may cause to a single receptor, which is approximately 1.4% of the risk associated with the background air quality[21], and then is required to expeditiously reduce its impact.

Section 4.1 of the DEIR identifies the objectives for proposed rule 12-16 inaccurately. To state that the objective is to protect "*air quality*" and "*public health*" is to imply that the existing myriad of Federal, State, and District air rules and permitting requirements that have accumulated over the last several decades and are statutorily required to do exactly that have been inadequate, and that the District has been failing to do its job for the last 62 years. And as noted in our cover letter for these comments, the restriction of GHG emissions from the refineries' sites does not necessarily protect the climate; it could instead cause increases in global GHG. This was the case with the Low Carbon Fuel Standard Brazilian ethanol mandate that WSPA identified in its comment letter on the 2017 Draft Clean Air Plan Program EIR. Transportation fuels are a global market that involve global steps (from exploration and production to refining and distribution), and anything that involves perturbing one of those steps may have unforeseen consequences elsewhere.

Section 4.2.1 is not an accurate depiction of the no-project alternative for Regulation 11-18 and therefore it and the corresponding analysis in Section 4.4.1.1 do not comply with the CEQA regulations at 14 CCR 15126.6(e), which require that *"...The 'no project' analysis shall discuss the existing conditions at the time the notice of preparation is published...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...."* It is reasonably expected that US EPA will fulfill its statutory requirement under Section 112(d)(6) of the Clean Air Act to periodically review and revise its Maximum Achievable Control Technology (MACT) standards for Hazardous Air Pollutants (HAP). Additionally, the California ARB will continue to fulfill its statutory requirement under H&SC §39665 *et seq.* to periodically review/revise/update its Air Toxics Control Measures (ATCMs). Lastly, there will also be TAC emissions reductions associated with all of other existing regulatory programs at the Federal, State, and District level that reduce criteria pollutants since almost all TACs are also either criteria pollutants or precursors to criteria pollutants.

These programs are the primary reason that TAC emissions have decreased so substantially since the time the AB2588 requirements were promulgated nearly three decades ago (as shown in the District's Figure 3-1), and Sections 4.2.1 and 4.4.1.1 assume that none of them exist and/or are not reasonably expected to occur in the foreseeable future. WSPA made similar comments on the draft PEIR for the District's 2017 Clean Air Plan and the District did not respond to it as required by 14 CCR 15088(a).

Section 4.3.1 states that there are no facility-wide emissions limits on refineries; that is incorrect. There are facility-wide emissions limits, either spelled out explicitly in permits or as a result of equipment-specific emissions limits and/or equipment capacities ("potential to emit"). The District has already issued permits to the refineries and the entire point of these permits was to ensure the protection of public health if the refineries were to operate up to those maximum limits.

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[21] This percentage was calculated by dividing the 10-in-a-million threshold by the 690-in-a-million background level shown in Figure 3.2-1.

Expert Report of Greg Karras
Communities for a Better Environment (CBE)
8 May 2017

Regarding the
Draft Environmental Impact Report for
Proposed Regulation 11, Rule 18 (Rule 11-18) and
Proposed Regulation 12, Rule 16 (Rule 12-16),
Bay Area Air Quality Management District

Contents

I, Greg Karras, declare and say:

1. I reside in unincorporated Marin County and am employed as a Senior Scientist for Communities for a Better Environment (CBE). My duties for CBE include technical research, analysis, and review of information regarding industrial health and safety investigation, pollution prevention engineering, pollutant releases into the environment, and potential effects of environmental pollutant accumulation and exposure.

Qualifications

2. My qualifications for this opinion include extensive experience, knowledge, and expertise gained from more than 30 years of industrial and environmental health and safety investigation in the energy manufacturing sector, including petroleum refining, and in particular, refineries in the San Francisco Bay Area.

3. Among other assignments, I served as an expert for CBE and other non-profit groups in efforts to prevent pollution from oil refineries, to assess environmental health and safety impacts at refineries, to investigate alternatives to fossil fuel energy, and to improve environmental monitoring of dioxins and mercury. I served as an expert for CBE in collaboration with the City and County of San Francisco and local groups in efforts to replace electric power plant technology with reliable, least-impact alternatives.

4. I have served as an expert for CBE and other groups participating in environmental impact reviews of related refinery projects, including, among others, the "Contra Costa Pipeline Project," the "Phillips 66 Propane Recovery Project," the "Shell Greenhouse Gas Reduction Project," the "Chevron Richmond Refinery Modernization Project" and the "WesPac Pittsburg Energy Infrastructure Project" in the County of Contra Costa, and the "Phillips 66 Company Rail Spur Extension Project" in San Luis Obispo County. My work as an expert for CBE and other non-profit groups in a 2007–2008 review of the proposed Chevron Richmond refinery 'Hydrogen Renewal Project' was cited by the Appeals Court in support of CBE's subsequent successful advocacy regarding that proposed project (*See* *CBE v. City of Richmond* 184 Cal_Ap.4th).

5. During 2014 I served as an expert for the Natural Resources Defense Council in research on the effects of changes in oil feedstock quality on refinery air emission rates, specifically, on estimating toxic and particulate emissions from U.S. refinery cracking and coking of low quality, bitumen-derived "tar sands" oils.

6. As part of CBE's collaboration with the refinery workers union United Steelworkers (USW), community-based organizations, the Labor Occupational Health Program at UC Berkeley, and environmental groups, I served as an expert on environmental health and safety concerns shared by refinery workers and residents regionally. In this role I served as CBE's representative in the Refinery Action Collaborative of Northern California, and as an expert for CBE and other groups participating in the development of refinery emission control rules to be considered for adoption by the Bay Area Air Quality Management District.

7. I serve as one of CBE's experts supporting informal state-level climate and energy planning discussions with California State agencies and the Office of Governor Edmund G. Brown. In this capacity I participated in meetings organized and attended by

Governor Brown's senior advisors on 12 July 2013 in Oakland, California, 13 April 2015 in Sacramento, California, and 12 December 2016 in Sacramento, California.

8. I authored a technical paper on the first publicly verified pollution prevention audit of a U.S. oil refinery in 1989 and the first comprehensive analysis of regional oil refinery selenium discharge trends in 1994. From 1992–1994 I authored a series of technical analyses and reports that supported the successful achievement of cost-effective pollution prevention measures at 110 industrial facilities in Santa Clara County. I authored the first comprehensive, peer-reviewed dioxin pollution prevention inventory for the San Francisco Bay, which was published by the American Chemical Society and Oxford University Press in 2001. I authored an alternative energy blueprint, published in 2001, that served as a basis for the Electricity Resource Plan adopted by the City and County of San Francisco in 2002. In 2005 and 2007 I co-authored two technical reports that documented air quality impacts from flaring by San Francisco Bay Area refineries, and identified feasible measures to prevent these impacts.

9. I authored the first peer reviewed estimate of combustion emissions from refining lower quality crude oils to be based upon data from U.S. refineries in actual operation, which was published by the American Chemical Society in the journal *Environmental Science & Technology* in 2010. I authored a follow up to this national study that extended this work with a focus on California and Bay Area refineries, which was peer reviewed and published by the Union of Concerned Scientists in 2011. I authored and presented invited testimony regarding *inherently safer systems* requirements for existing refineries that change crude feedstock at the U.S. Chemical Safety Board's 19 April 2013 public hearing on the Chevron Richmond refinery fire. I authored a research report, published in January 2015, on the results of work I conducted for the Natural Resources Defense Council on estimating toxic and particulate emissions from U.S. refinery cracking and coking of low quality bitumen-derived oils.

10. In early 2016 I authored a concise summary of results from my research on trends in West Coast, California, and Bay Area oil refinery production, refined products demand and exports that was published by CBE as a fact sheet on the CBE Website.

11. In 2016 and early 2017 I participated in CBE's review and comment regarding the Scoping Plan for the State climate protection program proposed by the California Air Resources Board. My role in this review and these comments included, but was not

limited to, analysis and comment regarding the role of proposed Regulation 12, Rule 16 in statewide climate protection.

12. In 2016 and early 2017 I participated in CBE's review and comment regarding the State Implementation Plan (2017 Clean Air Plan) that was adopted by the Bay Area Air Quality Management District on 19 April 2017. My role in this review and these comments included, but was not limited to, analysis and comment on proposed Regulation 12, Rule 16, one of the measures to be developed under the adopted Plan.

13. I have participated actively in the development of proposed Regulation 12, Rule 16 and have reviewed the Draft Environmental Impact Report released by the Bay Area Air Quality Management District in March 2017 for this proposed measure and proposed Regulation 11, Rule 18.

14. My curriculum vitae and list of major publications are appended hereto as Attachment KR–1.

Scope of Review

15. Proposed Regulation 12, Rule 16 (hereinafter "Rule 12-16" or the "proposed action") would establish numeric limits on annual mass emissions from each of five major oil refining facilities and three refinery support facilities in the San Francisco Bay Area. The limits would apply to emissions of greenhouse gases (CO_2e), fine particulate matter ($PM_{2.5}$), respirable particulate matter (PM_{10}), and the particulate matter precursors nitrogen oxides (NOx) and sulfur dioxide (SO_2). Direct emissions of these pollutants from oil refining are causally, strongly, and positively related to refinery energy consumption and are classed as "combustion emissions." Designed to prevent further increasing combustion emissions caused by changes in refinery oil feed quality or quantity so that other measures can more effectively reduce emissions, the limits would be set at levels that allow each facility's maximum annual emissions over the most recent five years reported, accounting for normal operational variability.

16. In the course of my work for CBE I have been asked for my professional opinion regarding whether the Draft Environmental Impact Report for the proposed action that was released by the Bay Area Air Quality Management District ("District") in March 2017 (the "DEIR") provided adequate information about:

(1) existing baseline conditions that affect oil refining emissions in the Bay Area;

(2) the potential oil refining emission increments that the proposed action to implement Rule 12-16 could prevent;

(3) the long-term local health hazards associated with refinery emissions that Rule 12-16 could prevent;

(4) the short-term "episodic" local health hazards associated with refinery emissions that Rule 12-16 could prevent; and

(5) the potential environmental impacts that could occur as side effects of implementing this action.

My opinions on these matters and the basis for these opinions are stated in this report.

Summary Answer

17. The DEIR did not provide adequate information about any of these topics. Readily available information the DEIR failed to disclose and evaluate reverses or substantially alters its conclusions regarding each topic. Had the District considered this information in the DEIR, the DEIR could have found that:

(1) Increasing combustion emissions caused by refining higher-emitting grades of oil in greater amounts is an existing baseline condition in the region.

(2) Rule 12-16 could prevent a refinery combustion emissions increment of as much as 40–100 percent regionally over 40 years.

(3) Among other harms, the local exposure reduction from preventing these emissions could avert ≈ 800–3,000 premature deaths in the Bay Area over 40 years, and avert a disparately severe per capita risk 8–12 times the regional risk from these preventable emissions in communities within 2.5 miles of refineries.

(4) Preventing these emissions would likely result in significantly reduced episodic emission hazards.

(5) A no-cost compliance option that is consistent with other plans and policies would not require any change to existing equipment or operation, and could thereby avoid any potential negative environmental impact of implementing Rule 12-16.

Oil Refining Emissions Baseline

18. Refinery combustion emissions are in a continuous state of change driven by burning varying amounts of fuel for energy to process oil feeds of varying quality in varying amounts, and also by secondary factors, such as the extent and effectiveness of engineered controls to capture varying fractions of the pollutants from burning that fuel. Other District control measures focus on these secondary factors. The objective of the proposed action to prevent increasing combustion emissions caused by changes in refinery oil feed quality or quantity (and thereby complement other measures to reduce emissions; DEIR at 2-4) seeks to intervene in the primary factors that are changing refinery combustion emission rates. Understanding the environmental effects of the proposed action, therefore, requires information about the baseline state of change in refinery emissions caused by changes in refinery oil feed quality and quantity.

19. Peer reviewed research published by the American Chemical Society in 2010 is appended hereto as Attachment KR-2. Att. KR-2 documented increasing combustion emissions associated with refining lower quality oil, and showed this effect has led to a greater regional emission rate in the Bay Area than those in other U.S. refining regions.

20. A concept paper published by the District in 2012 that identified the potential for changing oil feed quality to increase future refinery emissions, and announced plans for a new District rule to curb these emissions, is appended hereto as Attachment KR-3.

21. District Board Resolution 2014-07, adopted in 2014 and finding, among other things, that "all Bay Area refineries are in the process of infrastructure and crude oil changes that have the potential to result in significant worsening of air quality" is appended hereto as Attachment KR-4. Resolution 2014-07 directed District staff to develop Rule 12-16 to curb potential refinery emissions increases as part of a combination of measures to reduce refinery emissions as much as feasible.

22. An excerpt from the State Implementation Plan adopted by the District on 19 April 2017,[1] finding, among other things, that "crude slates being refined by Bay Area refineries have been changing recently, and they are expected to continue to change in the future" potentially increasing emissions, is appended hereto as Attachment KR-5.

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[1] Note that, as downloaded from the District Web Site on 28 April 2017, some pages of this excerpt from the Plan, which was adopted on 19 April 2017, are still marked "Draft."

23. Despite this clear and consistent intent to intervene in an ongoing switch to higher-emitting grades of oil by setting limits to "cap" increasing refinery emissions, the DEIR failed to disclose these existing baseline environmental conditions. In particular, its air quality analysis (*see* DEIR pp. 3.2-1 through 3.2-14) provided no information whatsoever about these oil quality-driven changes in refinery air emissions. In other words, the DEIR failed to disclose the problem Rule 12-16 is needed to solve.

24. A recent CBE technical report I authored, entitled *Combustion Emissions from Refining Lower Quality Oil Part 2: How Much Could a Switch to 'Tar Sands' Oil Increase Direct Emissions of $PM_{2.5}$ and CO_2 from Northern California Oil Refineries?*, is appended hereto as Attachment KR-6.

25. Ongoing declines in refinery oil supplies from both California and Alaska have forced Bay Area refineries to replace roughly half of their total oil feed with imported oil since 1988 and are expected to cause them to source ≈ 70–71%, and 84–89%, of the oil refined in the Bay Area from outside California by 2020, and 2050, respectively. (Attachment KR-6 at 9, 14, 15.)

26. Bay Area refiners have a wide range of choices for replacement oil supplies, including similar quality replacement oils. However, price discounts on low quality, higher-emitting grades of oil promise higher profits to refiners if environmental costs of refining those higher-emitting oils continue to be externalized. (Att. KR-6 at 10.)

27. Since 1990 refining lower quality oil was linked to specific emission impacts at one or more Bay Area plants in at least 20 separately documented cases, as the regional industry expanded energy-intensive heavy oil conversion capacity by at least 40 million barrels/year and increased its CO_2e emissions by an estimated 3.4 million tonnes/year. (Att. KR-6 at 3–5.)

28. At least eight industry plans to process greater volumes of low quality oil, including heavy and bitumen-derived "tar sands" oils, at Bay Area refineries have been announced, and at least 16 specific infrastructure projects that could implement those plans for Bay Area refineries have been reported, in recent years. (Att. KR-6 at 10–13.)

29. A full-blown switch to tar sands oil could more than double combustion emissions from refineries based on several experts' peer reviewed estimates. (Att. KR-6 at 6.)

30. A CBE fact sheet summarizing authoritative data showing a trend of increasing West Coast refinery gasoline and diesel exports as domestic demand for these fuels declines, and that Bay Area refineries account for a substantial portion of these exports, is appended hereto as Attachment KR-7. This information further supports the potential for Bay Area refiners to process greater amounts of higher-emitting grades of oil.

31. A U.S. Energy Information Administration report showing, among other things, that approximately 11 percent of the combined gasoline and diesel production by Bay Area refineries was exported overseas in 2013, is appended hereto as Attachment KR-8. This information indicates that Bay Area refinery combustion emissions were roughly 11 percent higher that year because of excess production for export, and illustrates the potential for increasing production for export to further increase refinery emissions.

32. The District could have disclosed and evaluated the baseline state of change in refinery combustion emissions caused by changing refinery oil feed quality and quantity in the DEIR. It could have done so based on readily available information, including the information upon which the District based its findings in attachments KR-3, KR-4, and KR-5, and the data, authoritative scientific opinion, and analysis provided to the District by previous comments in this matter. Had the District done so, the DEIR could have concluded that increasing combustion emissions caused by refining higher-emitting grades of oil in greater amounts is an existing baseline condition in the region.

Oil Refining Emission Increments

33. Incredibly, the DEIR concluded that if Rule 12-16 is not adopted other measures will reduce refinery combustion emissions (DEIR at 4-6) without disclosing or evaluating any information about the scale of the emissions increase that Rule 12-16 could prevent. This conclusion is not credible. The DEIR's failure to evaluate the refinery combustion emission increments the proposed action could prevent renders its assertion of this conclusion misleading, unsupported, and incorrect.

34. District staff could have estimated the refinery combustion emission increments that the proposed action could prevent in the DEIR using readily available information. Such information includes that upon which the District based its findings in attachments KR-3, KR-4, and KR-5, and the data, authoritative scientific opinion, and analysis

provided to the District by previous comment in this matter.[2] For example, although it could have used additional data and methods, District staff could have used the data, methods, and analysis that were documented in previous comment to support the range of potential emissions in plausible worst-case "tar sands" scenarios that was estimated in Attachment KR-6.

35. Data and results from Attachment KR-6 for oil feed quality-driven combustion emission increments are illustrated visually in Figure KR-1 below.

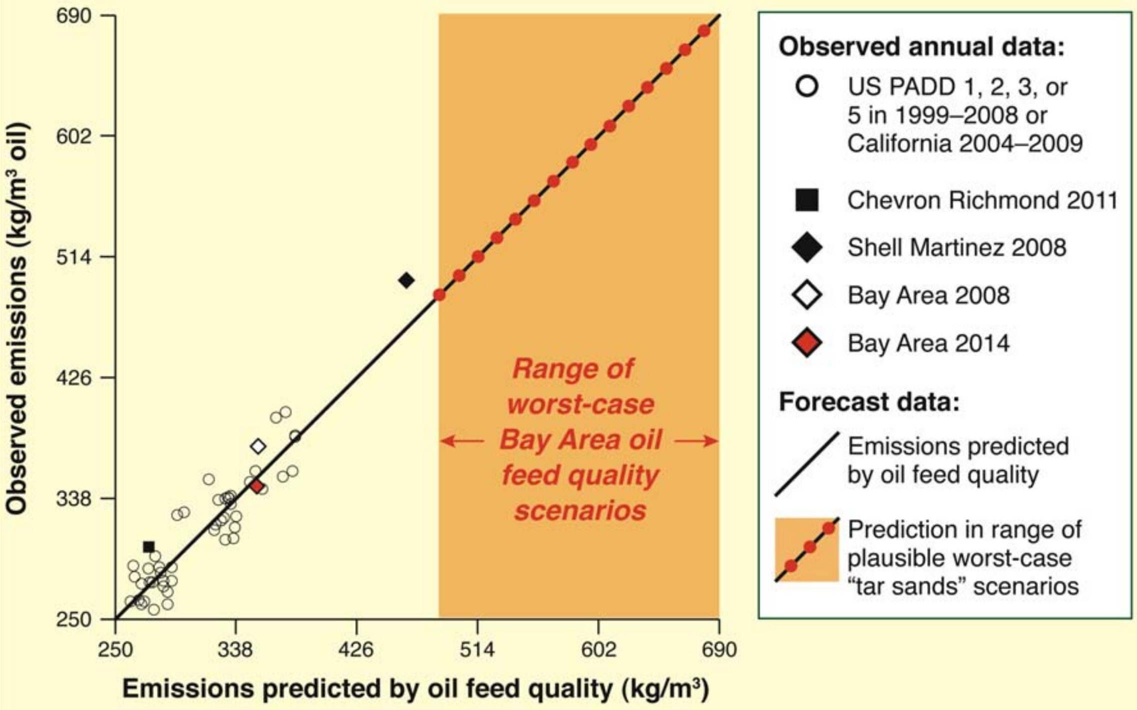

Figure KR-1. Bay Area refinery combustion emissions could increase by ≈ 40–100 % in the plausible worst-case low quality oil scenarios

Data and forecasts from American Chemical Society DOI: 10.1021/es1019965 (Karras, 2010) and Communities for a Better Environment's 2 December 2016 Technical Report to the Air Quality Management District, except Chevron 2011 data are from the California Air Resources Board (emissions), and City of Richmond EIR SCH #2011062042 (oil quality).

36. Observed (actual) refinery combustion emission increments are shown on the vertical axis of Figure KR-1. These 50 annual observations for the Bay Area, all

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[2] Among other relevant documents provided to the District as comment on proposed Rule 12-16, Attachment KR-2 was provided by CBE on 21 October 2015, Attachment KR-6 was provided by CBE on 2 December 2016, and documents cited and discussed in Attachment KR-6 were provided previously as noted below.

California refineries combined, and four U.S. refining regions that account collectively for 97 % of U.S. refining capacity are from peer reviewed data. (Att. KR-6.) Emissions are shown in units of mass per volume oil refined, so that the data are comparable across regions and years. Although these combustion emission increments represent all five pollutants limited by Rule 12-16, note that $PM_{2.5}$, PM_{10}, NOx, and SO_2 together account for less than 0.04 % of the combined refinery emissions mass (*Id.*), which is dominated by carbon dioxide (CO_2).

37. A 2017 report by the State Office of Environmental Health Hazard Assessment that, among other things, showed refinery $PM_{2.5}$ emissions are strongly correlated with refinery CO_2e emissions, is appended hereto as Attachment KR-9. This report provides further support for the finding of Attachment KR-6 that the subject emissions are causally, strongly, and positively related to refinery energy consumption.

38. Emissions predicted by oil feed quality are shown on the horizontal axis of Figure KR-1. These values are based on peer-reviewed data from U.S. (1999–2008), California (2004–2009), and Bay Area (2008) refinery operations (Att. KR-6) and a peer reviewed estimation method. (Att. KR-2.) The method uses partial least squares regression to predict refinery energy intensity (EI) from oil feed quality and process data, including:

- refinery oil feed density (d), in kg/m^3 oil refined;
- refinery oil feed sulfur content (S), in kg/m^3 oil refined;
- refinery atmospheric crude distillation capacity utilized (CU), in percent; and
- refinery products ratio (light liquids:other products; P_r), expressed as a quotient,

and then converts the resultant energy consumption (fuel combustion) increments estimated from the change in EI to emissions based on observed data. Details of these estimates and calculations are given in Attachment KR-6 (*see* Table 3, appendices).

39. For Bay Area refineries, Figure KR-1 shows results from this estimation method (¶ 38) based on peer reviewed data for 2008 (Att. KR-2) and, for 2014, Bay Area data from the State Air Resources Board, State Energy Commission, and U.S. Energy Information Administration that were provided to the District previously (Att. KR-6).

40. The thick, black, diagonal line that rises from left to right in Figure KR-1 depicts the central prediction for oil feed quality-driven emissions, based on actual observed data from U.S. refineries that are shown in the figure, the peer reviewed estimation method discussed above (¶ 38; Att. KR-2), and the observed (for future conditions, estimated) oil

quality and production data. This diagonal line illustrates the emission increments that are estimated (predicted based on oil quality) as refinery oil feed quality worsens.

41. Bay Area refining industry combustion emissions were predicted well by oil feed quality in both 2008 and 2014 using this method, as shown by the closeness of Bay Area observations to the diagonal line representing the central prediction in Figure KR-1. Oil quality effects on annual Bay Area refinery emissions were predicted within 5 %, while those on long-term average statewide refinery emissions during 2004–2009[3] were predicted within 1 %, by this method. (Att. KR-6 at 7–9.)

42. Peer reviewed reports by three independent research groups that quantified oil quality effects on refinery combustion emissions, and a Carnegie Endowment report by some of these same authors, are appended hereto as attachments KR-10 through KR-13.[4] These estimates used detailed modeling based on plausible assumptions about additional oil quality and processing details that are not yet reported publicly for Bay Area plants, and reported energy and emission intensity effects of similar scale to those estimated by the method in Attachment KR-2 for comparable oil quality and processing conditions.

43. A 2007 U.S. Geological Survey report that found each of 23 geologic basins on four continents contains at least 14.7 billion barrels of heavy oil, natural bitumen, or both is appended hereto as Attachment KR-14.[5] Attachment KR-14 estimated the average densities (957 and 1,030 kg/m^3) and sulfur contents (27.8 and 45.5 kg/m^3) of heavy oil and natural bitumen, respectively. These “tar sands” oils are much denser and more contaminated than the current Bay Area refinery oil feed. (Att. KR-6.)

44. The shaded box at the right of the chart in Figure KR-1 illustrates the range of Bay Area refining industry emission increments estimated in Attachment KR-6. This estimate is for Bay Area-wide refining emissions from 2020–2050. The left-hand edge of the shaded box represents the “Low Case” and the right-hand edge the “High Case” in this range of plausible worst-case tar sands oil scenarios. The points where the diagonal line (the central prediction based on oil feed quality) intersects the left-hand and right-hand edges of the box illustrate the range of emissions estimated in these scenarios.

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[3] *Refinery CO_2 Performance Measurement* (Karras, 2011) provides detailed data for this point, was provided to the District previously, on 21 October 2015, and is hereby incorporated herein.

[4] Attachments KR-10 through KR-13 were provided to the District previously, on 21 Oct. 2015.

[5] Attachment KR-14 was provided to the District previously, on 21 October 2015.

45. In the Low Case, although ≈ 70–90 % of the current Bay Area oil feed could be replaced by imports from outside California from 2020–2050 (¶ 25), 50 % of the current oil feed is assumed to be replaced by heavy oil. The new regional oil feed blend would thus have a density of ≈ 925 kg/m^3 and a sulfur content of ≈ 19.7 kg/m^3. (Att. KR-6.) Based on this oil feed quality, the estimation method summarized in paragraph 38, and long-term average statewide refinery capacity utilization and product slate data, regional refining industry combustion emissions are estimated at ≈ 486 kg/m^3 oil refined, an increment of ≈ 40 % from 2014 emissions. (*Id.*) This Low Case increment is illustrated in Figure KR-1 by the vertical space between the 2014 Bay Area data point and the point where the diagonal line intersects the left-hand edge of the shaded box in the figure.

46. In the High Case, 80 % of the current oil feed is assumed to be replaced by a 50/50 blend of heavy oil and natural bitumen. The new regional oil feed blend would thus have a density of ≈ 975 kg/m^3 and a sulfur content of ≈ 31.7 kg/m^3. (*Id.*) The same estimation method and production data estimates emissions based on this oil feed quality at ≈ 690 kg/m^3 oil refined, or approximately double the 2014 emissions rate. (*Id.*)

47. Additional details of this potential emissions estimate are shown in Table KR-1, which includes all of Table 3 in Attachment KR-6 except for the change in table number. Note that the superscript numbers in the notes at the bottom of this table refer to the references and notes in Attachment KR-6.

48. Several comparisons with other data support this estimate. For total combustion emissions, this estimate (486–690 kg/m^3) is consistent with the range of emissions that Gordon et al. estimated for refining six high-carbon crude oil streams (500–630 kg/m^3; Att. KR-13), and with observed Shell Martinez refinery emissions in 2008 (≈ 497 kg/m^3; Att. KR-6). For $PM_{2.5}$ emissions alone, this estimate (0.031–0.044 kg/m^3) is consistent with the range of actual observed emissions from the two highest PM-emitting Bay Area refineries in 2014 (0.028–0.046 kg/m^3; Att. KR-6). In terms of reliability of prediction, emission increments estimated (40–100 %) far exceed the power of prediction shown for this estimation method based on site-specific Bay Area data (+/– 5 %; Att. KR-6).

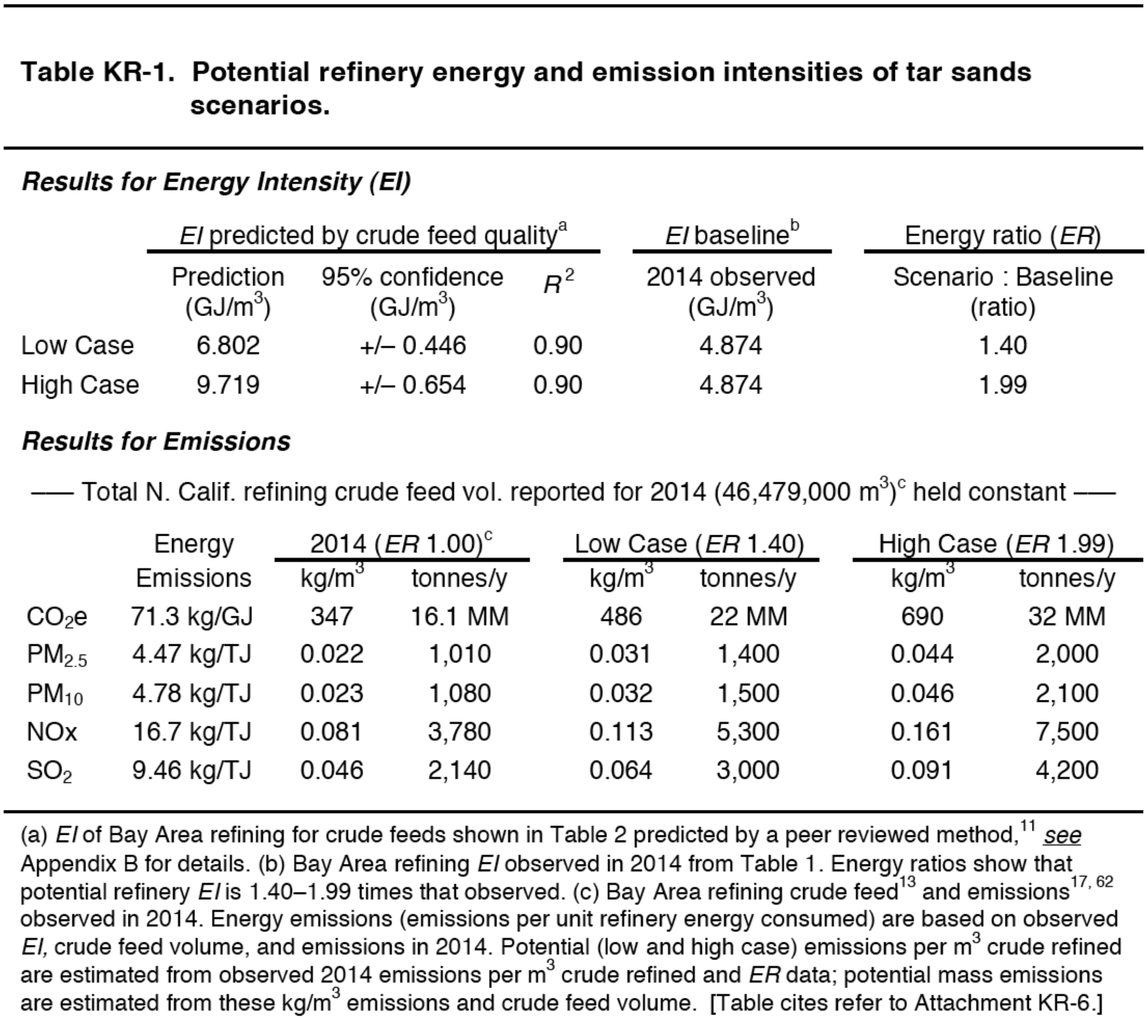

Table KR-1. Potential refinery energy and emission intensities of tar sands scenarios.

Results for Energy Intensity (EI)

	EI predicted by crude feed quality[a]			*EI* baseline[b]	Energy ratio (*ER*)
	Prediction (GJ/m^3)	95% confidence (GJ/m^3)	R^2	2014 observed (GJ/m^3)	Scenario : Baseline (ratio)
Low Case	6.802	+/– 0.446	0.90	4.874	1.40
High Case	9.719	+/– 0.654	0.90	4.874	1.99

Results for Emissions

—— Total N. Calif. refining crude feed vol. reported for 2014 (46,479,000 m^3)[c] held constant ——

	Energy	2014 (*ER* 1.00)[c]		Low Case (*ER* 1.40)		High Case (*ER* 1.99)	
	Emissions	kg/m^3	tonnes/y	kg/m^3	tonnes/y	kg/m^3	tonnes/y
CO_2e	71.3 kg/GJ	347	16.1 MM	486	22 MM	690	32 MM
$PM_{2.5}$	4.47 kg/TJ	0.022	1,010	0.031	1,400	0.044	2,000
PM_{10}	4.78 kg/TJ	0.023	1,080	0.032	1,500	0.046	2,100
NOx	16.7 kg/TJ	0.081	3,780	0.113	5,300	0.161	7,500
SO_2	9.46 kg/TJ	0.046	2,140	0.064	3,000	0.091	4,200

(a) *EI* of Bay Area refining for crude feeds shown in Table 2 predicted by a peer reviewed method,[11] *see* Appendix B for details. (b) Bay Area refining *EI* observed in 2014 from Table 1. Energy ratios show that potential refinery *EI* is 1.40–1.99 times that observed. (c) Bay Area refining crude feed[13] and emissions[17, 62] observed in 2014. Energy emissions (emissions per unit refinery energy consumed) are based on observed *EI*, crude feed volume, and emissions in 2014. Potential (low and high case) emissions per m^3 crude refined are estimated from observed 2014 emissions per m^3 crude refined and *ER* data; potential mass emissions are estimated from these kg/m^3 emissions and crude feed volume. [Table cites refer to Attachment KR-6.]

49. Had the District considered this information, it could have included an estimate in the DEIR that, over time, the proposed action could prevent a region-wide refinery combustion emissions increment of as much as +40–100 % from 2014 emissions. Then, it could have compared this estimate with the refinery combustion emissions reductions of ≈ 20 % that the District expects other measures to achieve (Att. KR-4; 2017 Clean Air Plan) and found that, should Rule 12-16 not proceed, refinery combustion emissions could not be reduced as much as feasible and instead could increase substantially.

50. The DEIR failed to provide adequate information about refinery emissions the proposed action could prevent, and failed to disclose readily available information that, when disclosed and considered, reverses the DEIR's conclusions regarding Rule 12-16.

Local Health Benefits—Chronic Exposure

51. Having failed to disclose or evaluate the air pollutant emissions the proposed action could prevent, the DEIR failed to disclose or evaluate the local health benefits of preventing exposures to that excess air pollution. First, the DEIR erroneously implied that disparately severe local air impacts of oil refining—the largest industrial source of $PM_{2.5}$ in the Bay Area, which hosts the second largest refining center in western north America (Att. KR-6 at 2)—could not occur over large parts of this region. Then the DEIR failed to include any estimate of health benefits from implementing Rule 12-16 either regionally, or in low-income communities of color on the refinery fence lines.

52. A 2 December 2016 comment letter to the District signed by nine public health and medical professionals and experts in support of Rule 12-16 is appended hereto as Attachment KR-15.[6] Among other things this letter notes that "particulate matter is associated with severe health effects, including premature mortality, cardiovascular and pulmonary disease, heart attacks, strokes, and cancer" and that vulnerable populations, "especially those closest to the refineries, are at greatest risk."

53. A 2009 peer reviewed report on air quality and health research sponsored by the National Institute for Environmental Health Sciences is appended hereto as Attachment KR-16. Among other things, this report demonstrated, based on direct measurements of chemically-fingerprinted air pollution, that refinery and port combustion of heavy oil[7] was a more important factor than traffic in the elevated ambient air concentrations of $PM_{2.5}$ measured in communities ≈ 2.5 miles from the Richmond refinery.

54. A 2010 report on statewide research that documented disparately severe PM_{10} emission burdens on low-income communities of color within 2.5 miles of refineries and other major industrial sources of CO_2e is appended hereto as Attachment KR-17.

55. A 2015 technical comment that, among other things, showed that the areal $PM_{2.5}$ emission intensity (emissions mass per area, e.g., $tons^{-yr}$ per square mile) of oil refining within 2.5 miles of Bay Area refineries is more than two times that for all sources combined averaged over the region as a whole, is appended hereto as Attachment KR-18.

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[6] This document is timely dated for scoping comment on the DEIR and was posted as received on the District Web Site, but like some of CBE's comments, it was not included in the DEIR itself.

[7] In that study "heavy oil" means heavy marine fuel oil and petroleum coke; marine use of those fuels is restricted in S.F. Bay, although refineries are allowed to and do burn petroleum coke.

56. District staff has quantified health benefits for other $PM_{2.5}$ control measures, in the State Implementation Plan. (Att. KR-5.) Among other impacts, District staff found exposures to anthropogenic $PM_{2.5}$ are associated with 2,500 premature deaths/year in the region. (*Id.*) District staff estimated that each 1 $\mu g/m^3$ increase in long-term population exposure to $PM_{2.5}$ is associated with a 1 % increase in a population's annual death rate, and estimated exposures from emissions for each part of the region based on modeling trued-up to air measurements. (*Id.*) Long-term exposures prevented by cutting $PM_{2.5}$ emissions by 2.8 tons/day were estimated to avert 76 premature deaths/year. (*Id.*)

57. District staff could have quantified the health benefits of Rule 12-16 in the DEIR. For example, among other health benefits, it could have estimated the premature deaths of adults averted by the proposed action, based on the emission increments estimated in Attachment KR-6 and the data provided in attachments KR-5 and KR-15 through KR-18.

58. Estimates of premature deaths that could be averted by the proposed action, regionally and within 2.5 miles of refinery fence lines, that were developed as part of an ongoing collaboration of public health professionals and air monitoring experts with CBE are appended hereto as Attachment KR-19. The estimates were based on emissions, exposure, and population-level risk data and estimates for $PM_{2.5}$ from attachments KR-5, KR-6, and KR-15 through KR-18, and conservative assumptions that may underestimate health impacts in vulnerable populations. The estimates are summarized in Table KR-2.

59. These estimates appear conservative compared with the District's estimate in ¶ 56 for cutting $PM_{2.5}$ emissions 2.8 short tons/day (927 tonnes/yr). The District estimates a risk of ≈ 0.08 deaths/tonne emitted (76 deaths/yr ÷ 927 tonnes/yr = 0.082 deaths/tonne). At the same regional scale, the estimates in Table KR-2 for $PM_{2.5}$ emission increments in Table KR-1 suggest a risk of ≈ 0.05–0.07 deaths/tonne emitted.

60. As shown in Table KR-2, without Rule 12-16 the District can anticipate increases in all-cause mortality attributable to chronic exposures to refinery-emitted particulate matter, and a disparately severe burden from these preventable exposures in already-vulnerable communities within 2.5 miles of refineries. These nearby communities face a risk of premature death in the "no project" alternative 8–12 times the average regional risk. Our estimates indicate that, had the District estimated health outcomes based on readily available information, the DEIR could have concluded that Rule 12-16 would be expected to avert ≈ 800–3,000 premature deaths associated with $PM_{2.5}$ exposures over the

Table KR-2. Potential health impact of Rule 12-16: Averted all-cause deaths attributable to chronic exposures to oil refinery $PM_{2.5}$ air pollution

For fine particulates ($PM_{2.5}$)	Regional (nine counties)			Within 2.5 miles of refineries		
	Low	Medium	High	Low	Medium	High
Parameters						
Adult population [a]		5,144,345			81,666	
Baseline deaths/year [b]		42,905			751	
$PM_{2.5}$ risk factor per µg/m^3 [c]	0.8 %	1.0 %	1.2 %	0.8 %	1.0 %	1.2 %
Refining exposure baseline (µg/m^3) [d]	0.285	0.285	0.285	2.55	2.55	2.55
Refining emissions increment (%) [e]	40 %	70 %	100 %	40 %	70 %	100 %
Exposure/emission ratio [f]	0.5	0.5	0.5	0.4	0.5	0.6
Impact						
$PM_{2.5}$ exposure averted (µg/m^3) [g]	0.057	0.100	0.142	0.408	0.892	1.53
Annual deaths averted per million [h]	3.80	8.30	14.3	30.0	82.1	169
Cumulative deaths averted (40 yrs.) [h]	800	1,700	2,900	98	270	550

(a) Adult (>25) population from U.S. Census, State Health and Finance depts. data; _see_ Att. KR-19 for details.

(b) From baseline county age-specific death rates for all causes excluding suicide and accidents reported by the State depts. of health, and of finance; _see_ Att. KR-19 for details. The ≤ 2.5 miles from refineries estimate may underestimate impact since populations near refineries may experience higher death rates than county-wide averages, and because disparate impacts also occur in communities > 2.5 miles from refineries.

(c) For every 1 µg/m^3 there is a 1% increase in risk of all-cause mortality relative to the baseline death rate. Estimate from BAAQMD: _see_ Attachment KR-5. Low and high cases reflect the confidence interval of this estimate per BAAQMD's 17 April 2017 "Particulate Matter Rule Update" Staff Presentation (2,000–3,000 for a central estimate of 2,500). Risk may be underestimated as it does not account for greater toxicity of $PM_{2.5}$ emitted by refining, ultrafine particulate matter, and greater vulnerability of environmental justice populations.

(d) Baseline $PM_{2.5}$ exposure to refinery emissions, 5% of total anthropogenic exposure (5.7 µg/m^3) regionally (Att. KR-5 at 2/20, C/7), but refinery emissions can dominate elevated PM burdens at 2.5 miles (Att. KR-17). Site-specific measurements that were chemically fingerprinted to sources (Att. KR-16) showed burning a fuel that is burned legally in the vicinity only by refineries is a more important factor than traffic in a 4.5 µg/m^3 summer-median anthropogenic exposure at 2.5 miles. Areal source strength (mass/m^2) data show Bay Area refineries account for >70% of total all-source regional average emission strength for direct $PM_{2.5}$ emissions 2.5 miles from their fence lines (Att. KR-18), however, some of the emissions loft over nearby communities and disperse. Robust data supported adjusting the 4.5 µg/m^3 summer value to a 5.1 µg/m^3 annual average (Att. KR-19). These data together bound the estimate to approx. half anthrop. exposure (50% of 5.1 µg/m^3). This (≤2.5 m.) value may underestimate impact, as it does not account for exposure from multiple refineries.

(e) Refinery emissions increment from a planned switch to low-quality "tar sands" oil that Rule 12-16 caps would prevent (+40–100% from 2014 emissions; midpoint +70%): _see_ Table KR-1 and Attachment KR-6.

(f) The change in exposure for a given change in emissions, expressed as a ratio, such that a ratio of 0.5 means exposure (µg/m^3) changes 0.5% for each 1% change in mass emission. Estimates use BAAQMD (Att. KR-5) regional wtd. avg. (0.5) and, for ≤ 2.5 miles, the mid–high end of BAAQMD's modeled range (0.2–0.6).

(g) The $PM_{2.5}$ exposure averted by Rule 12-16, calculated by multiplying the baseline $PM_{2.5}$ exposure to refinery emissions (*times*) the refinery emissions increment (*times*) the exposure/emissions ratio.

(h) Calculated as the $PM_{2.5}$ risk factor (*times*) the $PM_{2.5}$ exposure averted (*times*) the baseline deaths/year to yield annual deaths averted, which is expressed in two ways. Annual deaths averted/1,000,000 population is annual deaths averted (*times*) 1,000,000 (*divided by*) adult population. Annual deaths averted (40 yrs.) is annual deaths averted (*times*) 40, and is shown since capital projects planned to enable the switch to higher-emitting tar sands oil (which Rule 12-16 would limit or prevent) generally operate for 30–50 years.

likely operational duration of projects to refine low-quality oil in the Bay Area. Equally important, our estimates show that, had the District estimated health impacts based on readily available information, the DEIR could have concluded that the "no project" alternative would likely result in significant and disparately severe increases in mortality burdens on already-disadvantaged communities near refineries.

Local Health Benefits—Acute Exposures

61. Acute exposures to episodic refinery emissions in nearby communities can result in a broad range of adverse health outcomes up to and including premature death. (Att. KR-15.) Among other data, flaring data link episodic emissions from Bay Area refineries to lower quality oil feeds. (*See* Att. KR-6 at 4.) Designed to achieve objectives that include protecting community health from these acute exposure hazards (DEIR at 2-4), Rule 12-16 features a no-cost compliance option, discussed below, that would function as an incentive to avoid lower quality oil feeds, thereby preventing or limiting increases in the frequency and magnitude of episodic refinery emissions. The DEIR failed to disclose this disparately severe local impact of the "no project" alternative, failed to disclose this benefit of the proposed action, and failed to provide adequate information about the short-term episodic emission hazards that Rule 12-16 could prevent.

62. District staff could have disclosed and evaluated episodic emission hazards associated with lower quality oil feeds based on readily available information, including, but not limited to, the information identified and discussed in paragraphs 63–69.

63. Converting denser, more contaminated, lower quality oil feeds to engine fuels requires more intensive processing at high temperatures and pressures that increases the volumes of contaminated gases and petroleum coke created as byproducts of conversion processing. (Att. KR-2.) Thus, refining lower quality oil increases the volumes of contaminated and flammable gases contained at high temperatures and pressures in refinery process vessels, including gases that are partially decontaminated and then used as refinery fuel gas. The District has previously found that such changes in gas quality and quantity are causal factors in episodic flaring at refineries, and has adopted a flare emission analysis requirement (District regs. § 12-12-401.4.2) based on this finding.

64. A 2006 District Staff Report that found, among other things, flare episodes have caused disparately elevated local air pollution and have the potential to affect community health near Bay Area refineries, is appended hereto as Attachment KR-20.

65. A 2013 U.S. Chemical Safety Board report that found, among other things, switching to higher-sulfur crude accelerated sulfidic corrosion that led to catastrophic piping failures and fires at the Chevron Richmond refinery in 2007 and 2012, is appended hereto as Attachment KR-21.

66. A 2001 U.S. Chemical Safety Board report on a 1999 Martinez refinery fire is appended hereto as Attachment KR-22. This report found, among other things, that switching to denser crude overwhelmed a crude desalting unit, resulting in corrosion product plugging of the crude unit downstream, which was undetected until the plug released during maintenance, fueling a fatal fire.

67. These Chemical Safety Board reports demonstrate that, by causing increasingly severe processing conditions that have damaged refinery equipment repeatedly, refining lower quality oil is a recurrent causal factor in major fires that injured and killed workers and caused acute exposure impacts affecting at least 15,000 nearby Bay Area residents. (Attachments KR-21; KR-22.)

68. This information (¶¶ 63–67) shows that lower quality oil feeds increase process severity, the frequency of equipment failures and process gas imbalances, the volumes of flammable and contaminated materials that are available to be released in those failures and imbalances, and thus the frequency and magnitude of refinery emission episodes.

69. By limiting refinery combustion emissions at maximum current rates (¶ 15), Rule 12-16 would prevent a foreseeable major switch to lower quality oil feeds that increase refinery emissions more than other measures could reduce those emissions (¶ 49), thereby limiting the oil quality-driven increases in episodic emissions discussed in ¶¶ 61–68. Moreover, by allowing each facility's current maximum emissions (¶ 15), these limits also offer a no-cost compliance option, allowing refiners to avoid the cost of new engineered controls to mitigate emission increases from lower quality oil feeds, thereby potentially preventing a gradual shift to lower quality oil.

70. Had District staff considered the information in paragraphs 18–32 and 63–69 in the DEIR, the DEIR could have concluded that, as compared with the "no project"

alternative, Rule 12-16 would likely result in significantly reduced episodic emission hazards in disparately impacted communities near refineries.

Potential For Unintended Impacts

71. As stated, by allowing each facility's current maximum emissions (¶¶ 15, 69), Rule 12-16 offers a no-cost compliance option, allowing refiners to avoid the cost of new engineered controls to mitigate emission increases from lower quality oil feeds, thereby potentially preventing a gradual shift to lower quality oil.

72. The DEIR assumed that refinery emissions will increase, refiners will install costly new engineered controls to capture a larger fraction of those emissions and meet the limits in Rule 12-16, and those costly new controls will cause significant impacts that cannot be mitigated—all without disclosing the incentive offered by this no-cost option. The DEIR provided no evaluation of the strength of the incentive this option provides refiners to avoid new costs, analysis of this option as mitigation for the "unmitigable" impacts alleged, or consideration of whether Rule 12-16 may be necessary to achieve emissions cuts that other regional and state air quality and climate measures seek. (¶ 49.) The DEIR then compounded its error by concluding that the proposed action is not part of an environmentally superior alternative based on these unfounded assumptions.

73. District staff could have compared all Rule 12-16 compliance options in the DEIR, including continuing current operations without refining lower-quality oil or expanding production capacity, in light of the information given in paragraphs 18–72. Had the District staff done so, the DEIR could have concluded that a no-cost compliance option which is consistent with other plans and policies would not require any change to existing equipment or operation, and could thereby avoid any potential negative environmental impact of implementing Rule 12-16.

74. I have given my opinions on these matters based on my knowledge, experience and expertise and the data, information and analysis discussed in this report.

I declare under penalty of perjury that the foregoing is true of my own knowledge, except as to those matters stated on information and belief, and as to those matters, I believe them to be true.

Executed this 8th day of May 2017 at Richmond, California

Greg Karras

Attachments List

Attachment KR-1. Karras, Greg. Curriculum Vitae and list of major publications.

Attachment KR-2. Karras, 2010. Combustion Emissions from Refining Lower Quality Oil: What Is the Global Warming Potential? *Environmental Science & Technology* **44**(24): 9584–9589. DOI: 10.1021/es1019965. Includes Supplemental Information (SI).

Attachment KR-3. BAAQMD, 2012. *Regulatory Concept Paper; Petroleum Refining Emissions Tracking Rule.* Bay Area Air Quality Management District: San Francisco, CA. Draft: 15 October 2012.

Attachment KR-4. BAAQMD, 2014. *A Resolution of the Board of Directors of the Bay Area Air Quality Management District Addressing Emissions from Bay Area Petroleum Refineries;* Bay Area Air Quality Management District: San Francisco, CA. Resolution 2014-07, adopted 15 October 2014.

Attachment KR-5. Excerpts from the State Implementation Plan Adopted by BAAQMD 19 April 2017; *2017 Clean Air Plan;* Bay Area Air Quality Management District: San Francisco, CA. Excerpts include 49 pages including cover sheet identifying contents.

Attachment KR-6. Karras, 2016a. *Combustion Emissions from Refining Lower Quality Oil Part 2: How Much Could a Switch to 'Tar Sands' Oil Increase Direct Emissions of* $PM_{2.5}$ *and* CO_2 *from Northern California Oil Refineries?;* A CBE Technical Report. Communities for a Better Environment (CBE): Richmond, CA. Provided to the Bay Area Air Quality Management District as comment on the scope of the Draft Environmental Impact Report for proposed Regulation 12, Rule 16. 2 December 2016.

Attachment KR-7. Karras, 2016b. *New Climate Threat: Will Oil Refineries Make California the Gas Station of the Pacific Rim?* A CBE Fact Sheet. Communities for a Better Environment (CBE): Richmond, CA. January 2016. Two pages including references and notes.

Attachment KR-8. USEIA, 2015. *PADD 5 Transportation Fuels Markets;* U.S. Department of Energy, U.S. Energy Information Administration: Washington, D.C. September 2015.

Attachment KR-9. OEHHA, 2017. *Tracking and Evaluation of Benefits and Impacts of Greenhouse Gas Limits in Disadvantaged Communities: Initial Report;* Office of Environmental Health Hazard Assessment, California Environmental Protection Agency: Sacramento, CA. Feburary 2017.

Attachment KR-10. Abella and Bergerson, 2012. Model to Investigate Energy and Greenhouse Gas Emissions Implications of Refining Petroleum. *Environmental Science & Technology*. **46:** 13037–13047. DOI: 10.1021/es3018682. Includes excerpts from crude oil inventory data developed for this analysis from www.ucalgary.ca/lcaost/prelim.

Attachment KR-11. Bredeson et al., 2010. Factors Driving Refinery CO_2 Intensity, with Allocation into Products. *International Journal of Life Cycle Assessment* **15:** 817–826.

Attachment KR-12. Brandt, 2011. Variability and Uncertainty in Life Cycle Assessment Models for Greenhouse Gas Emissions from Canadian Oil Sands Production. *Environmental Science & Technology*. **46:** 1253–1261. DOI: 10.1021/es202312p.

Attachment KR-13. Gordon et al., 2015. *Know Your Oil: Creating a Global Oil-Climate Index;* Carnegie Endowment for International Peace: Washington, D.C. www.CarnegieEndowment.org.

Attachment KR-14. Meyer et al., 2007. *Heavy Oil and Natural Bitumen Resources in Geological Basins of the World;* U.S. Geological Survey Open-File Report 2007–1084.

Attachment KR-15. Ostro et al., 2016. *Health and Safety Commentary Pertaining to Rule 12-16 and 11-18;* Comment letter signed by nine public health and medical professionals and experts in support of Rule 12-16. Submitted as comment to the Bay Area Air Quality Management District; San Francisco, CA, on the scope of the Draft Environmental Impact Report for proposed Regulation 12, Rule 16. 2 December 2017. Six pages including references.

Attachment KR-16. Brody et al., 2009. Linking Exposure Assessment Science With Policy Objectives for Environmental Justice and Breast Cancer Advocacy: The Northern California Household Exposure Study. *American Journal of Public Health* **99**(S3): S600–S609. DOI: 10.2105/AJPH.2008.149088.

Attachment KR-17. Pastor et al., 2010. *Minding the Climate Gap: What's at Stake if California's Climate Law Isn't Done Right and Right Away;* USC Program for Environmental and Regional Equity: Los Angeles, CA. Available at: https://dornsife.usc.edu/PERE/enviro-equity-CA-cap-trade.

Attachment KR-18. Karras, 2015. *Supplemental Comment on Air District Staff Proposal, Rules 12-15 and 12-16: Evidence of Localized Bay Area Refinery GHG and $PM_{2.5}$ Emission Impact;* Communities for a Better Environment (CBE): Richmond, CA. Technical comment provided to the Bay Area Air Quality Management District. 23 November 2015; revised 23 November 2015.

Attachment KR-19. *Assessment of impact of Rule 12-16 on mortality associated with chronic exposure to* $PM_{2.5}$ *from heavier oil feedstock processing in Bay Area refineries: appendices from health experts' collaboration report;* supporting information for: *Health comments on BAAQMD Rule 12-16 draft EIR: impacts and implications of alternatives scenarios and health context for environmental and regulatory settings.* Five appendices, including *Data and results for determining annual/summer exposure ratios: 24-hour* $PM_{2.5}$ *from the three nearest NAAQS stations to Bay Area oil refineries, 2013–2015,* and references.

Attachment KR-20. BAAQMD, 2006. *Staff Report: Proposed Amendments to Regulation 12, Miscellaneous Standards of Performance, Rule 12, Flares at Petroleum Refineries;* Bay Area Air Quality Management District: San Francisco, CA. 3 March 2006.

Attachment KR-21. USCSB, 2013. *Interim Investigation Report: Chevron Richmond Refinery Fire;* final report adopted April 2013. U.S. Chemical Safety and Hazard Investigation Board: Washington, D.C. www.csb.gov.

Attachment KR-22. USCSB, 2013. *Investigation Report: Refinery Fire Incident (4 Dead, 1 Critically Injured), Tosco Avon Refinery, Martinez, California, February 23, 1999;* Report No. 99-04-I-CA, March 2001. U.S. Chemical Safety and Hazard Investigation Board: Washington, D.C. www.csb.gov.

Greg Karras
Curriculum Vitae
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(510) 302-0430 x19

Work experience

1994 to present	**Position**	Senior Scientist
1984 to 1993		Research Associate
	Employer	Communities for a Better Environment (CBE)
	Description	Lead research in toxic pollution documentation and prevention projects—San Francisco Bay Area focus. Assistance to Executive Director, staff, members and Board in program plans and development. Lead responsibility for implementation, budget and coordination of staff in assigned campaigns and projects (1994–2000). Litigation assistance as expert witness. Shared responsibility to develop science as a tool for community organizing (1997–present).
1982 to 1984	**Position**	Research Associate
	Employer	Calif. Environmental Intern Program/Citizens for a Better Environment
	Description	Research, advocacy, and public education and fund raising supporting leak detection, clean up, and prevention program for underground chemical storage tanks in Los Angeles County.
1976 and 1977	**Position**	Student Assistant
	Employer	California Air Resources Board
	Description	Air pollution surveillance field sampling, laboratory analysis, and reporting of results for air quality predictions and alerts in South Coast Air Basin. Summers.

Other relevant experience

Member, American Association for the Advancement of Science.

Member, American Chemical Society.

Member, Refinery Action Collaborative.

Co-chair, San Francisco Alternative Energy Plan Load Forecasting and Power Flow Analysis and DSM–DG working groups. 2002–2004.

Member, Monitoring and TMDL Public Advisory Group to the California Water Resources Control Board. 2000.

Chair, Health Committee, CARAT Team established by the Coalition of Black Trade Unionists, Northern California Chapter. 1998–2000.

Co-organizer with staff, S.F. Bay Water Board and Zero Dioxin Alliance, national science symposia on dioxins. 1997.

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Combustion Emissions from Refining Lower Quality Oil: What Is the Global Warming Potential?

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The greenhouse gas emission intensity of refining lower quality petroleum was estimated from fuel combustion for energy used by operating plants to process crude oils of varying quality. Refinery crude feed, processing, yield, and fuel data from four regions accounting for 97% of U.S. refining capacity from 1999 to 2008 were compared among regions and years for effects on processing and energy consumption predicted by the processing characteristics of heavier, higher sulfur oils. Crude feed density and sulfur content could predict 94% of processing intensity, 90% of energy intensity, and 85% of carbon dioxide emission intensity differences among regions and years and drove a 39% increase in emissions across regions and years. Fuel combustion energy for processing increased by approximately 61 MJ/m^3 crude feed for each 1 kg/m^3 sulfur and 44 MJ/m^3 for each 1 kg/m^3 density of crude refined. Differences in products, capacity utilized, and fuels burned were not confounding factors. Fuel combustion increments observed predict that a switch to heavy oil and tar sands could double or triple refinery emissions and add 1.6–3.7 gigatons of carbon dioxide to the atmosphere annually from fuel combustion to process the oil.

Introduction

Replacing limited conventional crude oil (*1*) with heavy oil and natural bitumen (tar sands) resources could have substantial energy and environmental costs (*2*). Physical and chemical properties of the lower quality, heavier, more contaminated oils predict the combustion of more fuel for the energy necessary to convert them into product slates dominated by light hydrocarbon liquids (*3*−*8*). Preliminary estimates from fuel cycle analyses suggest that a switch to heavy oil and tar sands could increase the greenhouse gas emission intensity of petroleum energy by as much as 17−40%, with oil extraction and processing rather than tailpipe emissions accounting for the increment (*3, 4*). This raises the possibility that a switch to these oils might impede or foreclose the total reduction in emissions from all sources that is needed to avoid severe climate disruption. Accurate prediction of emissions from substitutes for conventional petroleum is therefore critical for climate protection. However, estimates of the emissions from processing lower quality oils have not been verified by observations from operating refineries.

Crude oils are extremely complex, widely ranging mixtures of hydrocarbons and organic compounds of heteroatoms and metals (*2, 7*). Refiners use many distinct yet interconnected processes to separate crude into multiple streams, convert the heavier streams into lighter products, remove contaminants, improve product quality, and make multiple different products in varying amounts from crude of varying quality (*5*−*11*). Factors that affect emissions from refinery process energy consumption include crude feed quality, product slates, process capacity utilization, fuels burned for process energy, and, in some cases, preprocessing of refinery feeds near oil extraction sites. Estimates that construct process-by-process allocations of emissions among these factors have not been verified by observations from operating refineries in part because publicly reported data are limited for refinery-specific crude feeds and unavailable for process-level material and energy inputs and outputs (*4*−*6*). Research reported here distinguishes effects of crude feed quality on processing from those of the other factors using refinery-level data from multiple operating plants to estimate and predict the process energy consumption and resultant fuel combustion emissions from refining lower quality oil.

Experimental Section

Refinery crude feed volume, density, and sulfur content, process capacity, capacity utilization, yield, and fuels were reported annually for each U.S. Petroleum Administration Defense District from 1999 to 2008 (*9, 10*). See the Supporting Information for this data (Table S1, Supporting Information). Districts 1 (East Coast-Appalachia), 2 (Midwest), 3 (Gulf Coast and vicinity), and 5 (West Coast, AK, and HI) each refined diverse crude feeds (19−41 source countries) at multiple facilities. Smaller, landlocked District 4 (Rocky Mountain states) refined nondiverse crude feeds (2−3 source countries).

At concentrations 4−8 times those of nitrogen and 160−500 times those of nickel and vanadium, sulfur is the major process catalyst poison in crude by mass (*2, 11*). In addition, for diverse blends of whole crude oils from many locations and geologic formations, distillation yield, and asphaltic, nitrogen, nickel, and vanadium content are roughly correlated with density and sulfur (*2, 7*). Variability in the effects of unreported crude feed characteristics on processing is thus constrained by the density and sulfur content of well-mixed crude feeds. Mixing analysis suggested that density and sulfur are reasonably reliable predictors of natural variability in unreported characteristics for annual crude feeds processed in Districts 1, 2, 3 and 5 but could not exclude the potential for unpredicted effects in processing the poorly mixed District 4 feed (Table S2, Supporting Information). The District 4 feed also was proportionately higher in synthetic crude oil (SCO) than those of other districts (Table S3, Supporting Information), and variant hydrogen production that was not predicted by crude feed density was found in District 4 (Table S4, Supporting Information). SCO may increase refinery hydroprocessing requirements (*12, 13*). High hydrogen capacity coincided with SCO refining in Districts 2 and 4 during 1999−2008, but the effect on refinery energy was minimal in District 2, while it was significant and more variable in District 4; other anomalies in the District 4 feed might cause this effect (Tables S2 and S4, Supporting Information). For these reasons, District 4 data were excluded from analysis of refinery observations and used only in estimates including upgrading for SCO. Districts 1, 2, 3, and 5 accounted collectively for 97% of U.S. refining capacity, 1999−2008. Analysis compared the reported data among these districts and years for interactions of the variables defined below.

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Oil quality *(OQ)* was defined as the density (*d*) and sulfur content (*S*) of crude feeds in mass per cubic meter (1 m^3, 6.29 barrels oil; 264 gallons). The density of crude oils is proportional to the fraction of higher molecular weight, higher boiling point, larger hydrocarbon compounds in the oils that are distilled in a vacuum, then cleaved (cracked) into fuel-size compounds to make light hydrocarbon fuels. The larger hydrocarbons have lower hydrogen/carbon ratios that require hydrogen addition to improve product quality and higher concentrations of sulfur and other catalyst poisons that are freed by cracking and bonded with hydrogen to remove them from the oil and protect process catalysts (*2, 11*). This hydrocracking and hydrotreating of gas oil and residua uses several times more hydrogen than does hydrotreating of lighter streams such as naphtha (*11*). These processing characteristics require increased capacity for vacuum distillation, cracking, and hydroprocessing of gas oil and residua in refineries designed to make light liquid products from heavier, higher sulfur crude oils (*4, 8, 14*).

Crude processing intensity (*PI*) was thus defined as the ratio by volume of vacuum distillation capacity, conversion capacity (catalytic, thermal, and hydrocracking), and crude stream (gas oil and residua) hydrotreating capacity to atmospheric crude distillation capacity. These processes account for the primary processing acting on the crude and "reduced crude" that *Speight* distinguishes from secondary processes acting on product streams such as gasoline, naphtha, and distillate oils (*7*). PI measures the increasing portion of the crude input fed to these processes that is predicted by worsening *OQ* (increasing *d*, *S*, or both) and indicates the additional energy needed for heat, pressure, and reactants such as hydrogen to process those increasing feed volumes. It also defines an operational distinction between "crude stream" processing that acts on crude, gas oils, and residua and the subsequent "product stream" processing that acts on the unfinished products from crude stream processing. This distinction was useful in the absence of reported data for more detailed process-level analyses of material and energy flows. *PI* was analyzed with refinery-level crude feed, fuel, capacity utilization, and product yield data to verify the refinery process energy predicted by *OQ*.

Energy intensity (*EI*) was defined as total refinery process energy consumed per volume crude feed, based on reported fuels consumed (Table S1, Supporting Information). Purchased fuels consumed by refiners, such as electric power from the transmission grid, were included in *EI*. Energy used by hydrogen production plants was estimated based on 90% of production capacity and data for new natural gas-fed steam methane reforming facilities (*10, 15*, Table S1, Supporting Information). *EI* integrates all factors in refineries that consume fuel energy, allowing analysis of *EI* with *OQ* and processing to account for refinery capacity utilized and yield.

Effects of variable product slates on refinery energy consumption were distinguished from those of *OQ* in five ways. First, product slate effects on the relationships observed among crude feed quality, crude stream processing, and energy were estimated directly. This was done by including the products ratio, defined as the volume of gasoline, kerosene, distillate, and naphtha divided by that of other refinery products, as an explanatory variable in comparisons of *OQ*, *PI*, and *EI*. Second, the products ratio, combined yield of gasoline and distillate, and combined yield of petroleum coke and fuel gas were analyzed with *EI* and *OQ*. This quantified changes in refinery energy with yield and changes in yield with crude feed quality for key conversion products and byproducts. Third, energy use was analyzed with product stream process capacities to estimate changes in *EI* that could be explained by changes in product processing rates. Fourth, effects of product stream processing on energy for hydrogen were compared with those of crude stream processing by analyzing hydrogen production capacity with product hydrotreating capacity, hydrocracking capacity, and *OQ*. Finally, estimated total energy for processing product slates (Eproducts) was analyzed with *OQ*. Eproducts was estimated based on product-specific factors developed by Wang et al. (*6*) and yield data (Tables S1 and S5, Supporting Information). Refinery capacity utilization was included as an explanatory variable in all comparisons.

Analysis was by partial least squares regression (PLS, XLSTAT 2009). PLS was used based on the expectation that explanatory (*x*) variables may be correlated, the primary interest in prediction of *y* (e.g., *EI*) and a secondary interest in the weights of *x* variables (e.g., *S* and *d*) in predicting *y*. Distributions of PLS residuals appeared normal (Shapiro-Wilk; Anderson-Darling; Lilliefors; Jarque-Bera tests, α 0.05).

Synthetic Crude Oil (SCO). Coking- and hydrocracking-based upgrading of bitumen in Western Canada uses energy to yield SCO that has poor gas oil and distillate qualities but lower density and sulfur than the bitumen (*12, 13*). Refinery crude feeds and energy consumption do not reflect the original bitumen quality for this SCO or the energy used in its upgrading. SCO comprised appreciable fractions of annual crude feeds in Districts 2 (2−8%) and 4 (2−12%), based on limited estimates that may exclude SCO in some blended oil streams (Table S3, Supporting Information). Process modeling data for energy consumed and density and sulfur lost in coking- and hydrocracking-based upgrading (*16*) were applied to the estimated SCO volume in refinery feeds (Table S3, Supporting Information). Districts and years were compared for total processing (upgrading and refining) energy estimated and that predicted by including estimated original oil quality (*d, S*) in the prediction mode of the PLS model based on refinery observations (Table S6, Supporting Information).

Emissions. Emissions were assessed for carbon dioxide (CO_2), the predominant greenhouse gas emitted by refineries (Table S7, Supporting Information). Direct measurements for all emission vents were not reported. Observed fuel consumption and fuel-specific emission factors developed by the U.S. Energy Information Administration (*17, 18*) were used to estimate "observed" emissions, and estimation details were documented (Table S1, Supporting Information). Fuel energy consumed ranged more widely among districts and years than the emission intensity of the fuel mix. Emissions predicted by *OQ* were based on *EI* predicted by *OQ* results from PLS and the emission intensity of the fuel mix. Observed and predicted emissions were compared among districts and years by PLS. Emissions estimates by government agencies (*5, 19−21*) that could be matched to data for *OQ* were superimposed on this comparison by including their *OQ* and predicted *EI* values in the prediction mode of the PLS models for the districts data (Tables S8 and S9, Supporting Information).

For heavy oil and natural bitumen, *OQ* data reported by the U.S. Geological Survey (*2*) and the average (1999−2008) U.S. refinery capacity utilization and products ratio were used in the prediction mode of the PLS model for observed *EI* versus *OQ* to predict *EI* (Table S8, Supporting Information). Predicted emissions from heavy oil and natural bitumen were derived from the products of these *EI* predictions (95% confidence for observations) and the emission intensity of the average (1999−2008) U.S. refinery fuel mix.

Results

Figure 1 shows results from comparisons of *OQ*, *PI*, and *EI* among districts and years from 1999 to 2008. Observed *OQ* ranges by 7.85 kg/m^3 crude feed (kg/m^3) for *S* and 37.6 kg/m^3 for *d*. Observed *PI* ranges by 0.42, or 42% of atmospheric crude distillation capacity. Observed *EI* ranges by 1.89 GJ/m^3 crude feed. *PI* is strongly and positively associated with

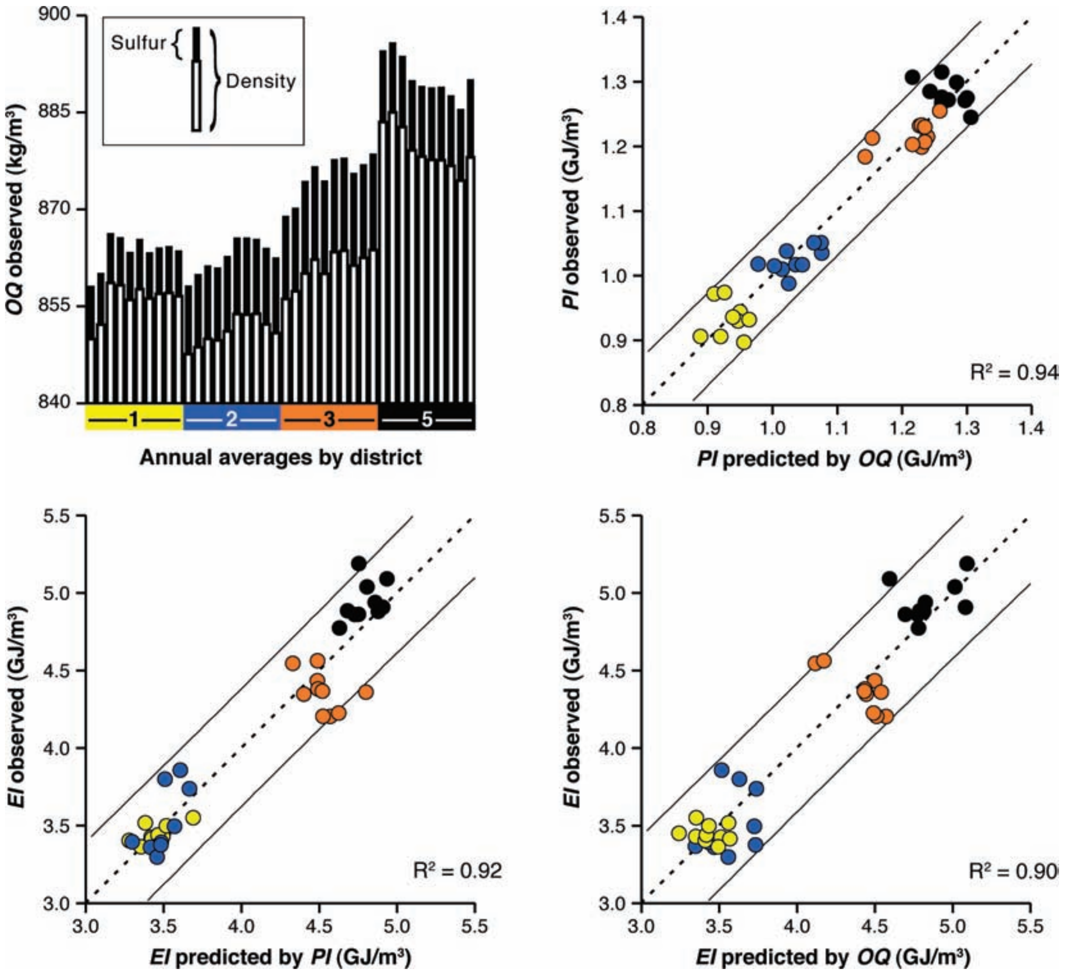

FIGURE 1. Increasing crude processing intensity and energy intensity with worsening oil quality. *OQ:* Crude feed oil quality. *PI:* Crude processing intensity. *EI:* Refinery energy intensity. Observations are annual weighted averages for districts 1 (yellow), 2 (blue), 3 (orange), and 5 (black) in 1999−2008. Diagonal lines bound the 95% confidence of prediction for observations.

worsening *OQ* (increasing *d*, *S*, or both). *EI* is strongly and positively associated with worsening *OQ* and increasing *PI*. *EI* increases by approximately 44 MJ/m^3 for each 1 kg/m^3 *d* and 61 MJ/m^3 for each 1 kg/m^3 *S* based on the PLS regression analysis for *EI* versus *OQ*. The equation of the model (*EI* vs *OQ*) can be expressed as

$$EI = 0.044d + 0.061S + 0.010(\text{Capacity utilized}) - 0.159(\text{Products ratio}) - 35.092 \quad (1)$$

where *EI* is the central prediction in GJ/m^3, *d* is in kg/m^3, *S* is in kg/m^3, capacity utilized is in percent, products ratio is expressed as a quotient, and the last term is the coefficient for the intercept.

Table 1 shows additional results from analysis of refinery observations. *PI* increases strongly with *d* and *S* (95% confidence for observations). *EI* increases strongly with *d* and *S* and with vacuum distillation, conversion, and crude stream hydrotreating capacities. Hydrogen production capacity increases strongly with *d* and hydrocracking capacity. Sulfur recovery capacity increases strongly with *S*. These observations describe increasing portions of crude feeds processed by crude stream capacity and resultant effects on total refinery energy consumption as crude density and sulfur content increase.

In contrast to crude stream processing, except for cracking byproducts and two processes that treat them, product slate indicators are not significant or decrease with increasing *OQ* and *EI*. The products ratio is not significant in the strong relationships among *EI*, *PI*, and *OQ*, perhaps in part because light liquids yield is less variable than *S* or *EI* among these districts and years. However, the ratio of light liquids to other products decreases with increasing *d* (products ratio vs *OQ)* and *EI* (*EI* vs products processing), and yield shifts, from gasoline and distillate to coke and fuel gas, as *OQ* worsens and *EI* increases.

Products processing reflects this shift from light liquids to cracking byproducts. Product stream hydrotreating, reforming, asphalt, aromatics, and polymerization/dimerization capacities decrease as *EI* increases. Those five processes account for 83−90% of total product stream processing capacity among districts (Table S1, Supporting Information). Among products processes, only alkylation and isomerization (7−13% of products capacity), which receive light streams from conversion processes, are positively associated with *EI*. Product hydrotreating cannot explain the observed increase in hydrogen production with increasing *d*. Estimated refinery energy use for products processing (Eproducts) decreases with increasing *d*. These results appear to measure the decreasing fraction of crude inputs converted to light liquid product streams and increasing creation of cracking byproducts such as coke and fuel gas that result from incomplete conversion as crude feed density and sulfur increase.

A weak inverse association of hydrogen production with product hydrotreating capacity (Table 1) results from a strong increase in H_2 capacity with *d* and hydrocracking, a steady decrease in the hydrotreating/hydrocracking ratio with increasing H_2 capacity, and lower hydrotreating at high

TABLE 1. Results from Refinery Crude Feed Quality, Processing, Energy, Yield, and Emission Comparisons[a]

effects of crude feed oil quality (*OQ*)

		standardized coefficients of *x* variables (coeff)			
y* vs *x	**R^2**	**density**	**sulfur**	**cap. utilized**	**products ratio**
process intensity *(PI)* vs *OQ*	0.94	**0.73**	**0.42**	**0.09**	−0.02
energy intensity *(EI)* vs *OQ*	0.90	**0.80**	**0.23**	0.05	−0.10
hydrogen production vs *OQ*	0.91	**1.09**	−0.01	0.05	**0.35**
sulfur recovery vs *OQ*	0.94	−0.01	**0.95**	−0.06	**−0.15**
pet. coke + fuel gas vs *OQ*	0.95	**0.80**	**0.34**	−0.04	
gasoline + distillate vs *OQ*	0.75	**−0.85**	−0.07	−0.04	
products ratio vs *OQ*	0.26	**−0.40**	−0.12	0.17	
Eproducts vs *OQ*	0.74	**−0.61**	0.13	**0.49**	

effects of oil quality (*OQ*) and fuels on CO_2 emissions

		standardized coefficients of *x* variables (coeff)	
y* vs *x	**R^2**	***EI* predicted by *OQ***	**fuel mix emission intensity**
observed vs predicted CO_2	0.85	**0.88**	−0.04

effects of processing and products yield

y* vs *x	**R^2**	**coeff.**	***y* vs *x***	**R^2**	**coeff.**
EI vs *PI*	0.92		*EI* vs yield	0.93	
vacuum distillation		**0.35**	pet. coke + fuel gas		**0.59**
conversion capacity		**0.35**	gasoline + distillate		**−0.42**
csHydrotreating		**0.22**	capacity utilized		−0.01
capacity utilized		**−0.16**	products ratio		−0.02
products ratio		−0.14			
			EI vs psProcessing	0.91	
H_2 production vs hydrocracking	0.97		psHydrotreating		**−0.17**
hydrocracking		**1.02**	reforming		**−0.19**
capacity utilized		−0.06	asphalt		**−0.30**
products ratio		**0.14**	aromatics		**−0.33**
			polym./dimerization		**−0.25**
H_2 production vs product-stream hydrotreating	0.18		lubricants		0.04
			alkylation		**0.30**
psHydrotreating		**−0.33**	isomerization		**0.24**
capacity utilized		−0.09	capacity utilized		−0.06
products ratio		**−0.17**	products ratio		**−0.33**

[a] *R*-squared values and standardized coefficients from PLS regressions on annual data from refining districts 1, 2, 3 and 5, 1999−2008. **Boldface**: significant at 95% confidence. Eproducts: estimated energy use to process a given product slate. Prefix cs (ps): crude stream (product stream) processing.

H_2 capacity among these districts and years (Figure S1, Supporting Information). Refinery capacity utilization was not significant in the effects of *OQ* on *EI* and affected the relationships between *PI* and *OQ* and between *PI* and *EI* only marginally, possibly because capacity utilization varied little among districts and years (Table S1, Supporting Information). Significant capacity utilization results are consistent with marginally increased energy consumption and decreased flexibility to process lower quality crude when refineries run closer to full capacity.

Rough estimates including the energy, *d*, and *S* lost in bitumen upgrading for SCO refined reveal greater effects of total processing for crude feeds refined in Districts 2 and 4 and follow the relationships observed in refining (Figure 2). Estimated total processing energy falls within the prediction based on *OQ* from refinery observations in 43 of 50 cases and exceeds the 95% confidence of prediction by more than 2% only in two cases explained by District 4 hydrogen anomalies discussed above. Oil quality−energy relationships observed in refining can predict those for total processing because upgrading and refining use similar carbon rejection, hydrogen addition, and utility technology.

Emissions calculated from observed fuels consumed are strongly and positively associated with *EI* predicted by *OQ* (Table 1) and range by 39%, from 257 to 358 kg/m^3 crude feed (Figure 3). Observed emissions fall within the 95% confidence of prediction based on *OQ* in 36 of 40 cases and are within 3% of the confidence of prediction in all cases. Despite emission differences among fuels, the fuel mix is not significant in this prediction. The emission intensity of the fuel mix varies much less than *EI* and decreases slightly with decreasing petroleum coke contributions and a shift in cracking processes as *EI*, *d*, and *S* increase (Table S1 and Figure S1, Supporting Information). Refinery emission estimates by government agencies that could be matched to *OQ* differ from each other by as much as 12−30% but fall within 2% of the central prediction based on *OQ* or within 4% of its confidence interval (*5, 19*−*21*, Table S8, Supporting Information). The 2008 San Francisco Bay Area estimate in Figure 3 (360 kg/m^3) is close to estimated 2008 California refinery emissions (354 kg/m^3) (*21*), for which matching *OQ* data were not available. California gasoline and diesel production may account for 56% (197.2 kg) and 22% (78.7 kg) of this 354 kg/m^3, respectively, based on fuel-specific estimates for the average California crude feed (*21*−*23*, Table S8, Supporting Information).

Predictions for heavy oil (957.4 kg/m^3 *d;* 27.8 kg/m^3 *S*) and natural bitumen (1 033.6 kg/m^3 *d;* 45.5 kg/m^3 *S*) (USGS average) (*2*) reflect their low quality compared with crude feeds observed (Figure 1). On the basis of the PLS model for

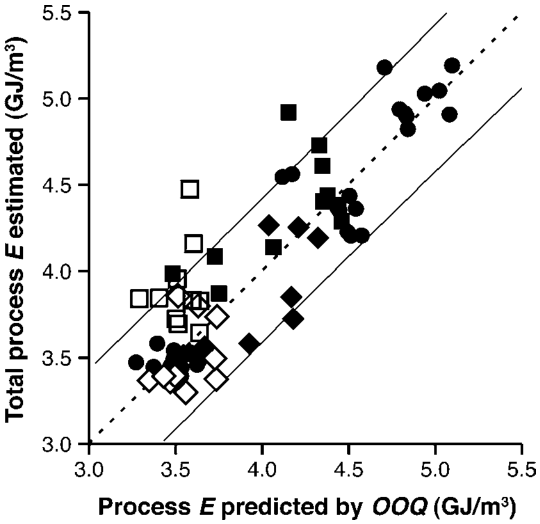

FIGURE 2. Estimated process energy for bitumen upgrading and refining versus that predicted by oil quality (GJ/m^3 crude), 1999–2008. *OOQ:* original oil quality including bitumen quality for synthetic oil inputs. Black diamonds: District 2. Black squares: District 4. Black circles: Districts 1, 3, and 5. White diamonds (squares): District 2 (District 4) refinery energy and oil quality only. Diagonal lines bound the 95% confidence of prediction for refinery observations.

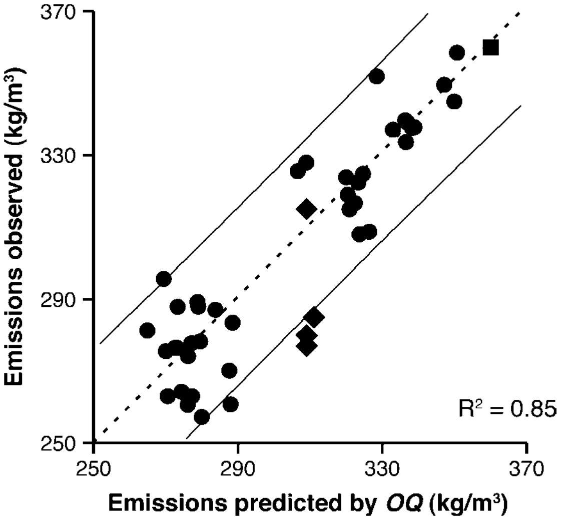

FIGURE 3. Refinery CO$_2$ emission intensity observed versus predicted by oil quality. *OQ:* Oil quality. Black circles: District 1, 2, 3, or 5 annually, 1999–2008. Black diamonds: United States in 2002, 2005, 2006, 2007. Black square: San Francisco Bay Area in 2008. Diagonal lines bound the 95% confidence of prediction for observations. R^2 value shown is for the comparison among districts and years.

observations from Districts 1, 2, 3, and 5 (*EI* vs *OQ*) and the emission intensity of the U.S. refinery fuel mix (73.8 kg/GJ), processing the range of heavy oil/bitumen blends could use 8.23–14.13 GJ/m^3 fuel (Table S8, Supporting Information) and emit 0.61–1.04 t/m^3 CO$_2$.

Discussion

Strongly coupled increases in energy and crude stream processing intensities with worsening oil quality (Figure 1) describe energy for carbon rejection, aggressive hydrogen addition, and supporting processes acting on larger portions of heavier, higher sulfur crude feeds to yield light liquid product streams. The creation of cracking reaction byproducts that limits conversion of heavier oils to light liquid product streams is observed in the shift from gasoline and distillate to coke and fuel gas yield as *OQ* worsens and *EI* increases. Observed decreases in light liquids yield and most major product stream processes as *EI* increases are consistent with this rising reliance on incomplete conversion. Differences in product slates cannot explain increasing *EI* as *OQ* worsens because capacities of processes comprising 83–90% of product stream processing capacity decrease as *EI* increases, and estimated energy use for products processing decreases as *OQ* worsens. Hydrogen production increases with crude density and hydrocracking. *EI* drives emissions variability. *OQ* predicts 94% of *PI*, *PI* predicts 92% of *EI*, and *OQ* predicts 90% of *EI* and 85% of emissions variability. These observations from operating plants across the four largest U.S. refining districts over 10 years provide evidence that crude feed density and sulfur content predict processing, energy, and CO$_2$ emission intensities for large groups of refineries with diverse feeds.

Slight, unexpected decreases in product hydrotreating at high hydrogen production and in fuel mix emission intensity with increasing *d* and *S* can be explained by a coincident shift from hydrotreating and catalytic cracking to hydrocracking with worsening *OQ*. Refiners can substitute hydrocracking for hydrotreating and catalytic cracking to some extent. *OQ*, along with other factors beyond this study scope, may influence those business decisions.

Energy increments predicted by density (44 MJ/kg) and sulfur (61 MJ/kg) in crude feeds (eq 1) compare to energy inputs of 40–70 MJ/kg density (including sulfur) lost from bitumen upgrading for SCO, based on process modeling of coking- and hydrocracking-based upgraders ((*16*), Table S6, Supporting Information). At an energy cost of 16.4 MJ/m^3 (Table S1, Supporting Information), hydrogen for density reduction by hydrocracking could account for 44 MJ/kg, based on the H$_2$/oil feed ratio of 308 m^3/m^3 Robinson and Dolbear report for 22°API feed and 44°API yield (*11*).

Results help to explain differences among government estimates of refinery emissions (Figure 3) and support the high case fuel cycle emission increments from a switch to heavy and tar sands oils reported for gasoline by Brandt and Farrel (+40%) (*3*) and for diesel by Gerdes and Skone (+17%) (*4*). Predicted emissions from processing heavy oil/natural bitumen blends (0.61–1.04 t/m^3) are 2–3 times the average of observed and estimated emissions in Figure 3 (0.30 t/m^3). Assuming this 0.30 t/m^3 refining average and 2007 world petroleum emissions (11.27 Gt) (*24*) as a baseline, processing heavy oil/bitumen blends at 2009 world refining capacity (5.06×10^9 m^3) (*10*) could increase annual CO$_2$ emissions by 1.6–3.7 gigatons and total petroleum fuel cycle emissions by 14–33%. Extraction emissions would add to these percentages.

This prediction applies to average CO$_2$ emissions from large, multiplant refinery groups with diverse, well-mixed crude feeds and appears robust for that application. However, the method used here should be validated for other applications. If it is applied to different circumstances, the potential for significantly different product slates, poorly mixed crude feeds, synthetic crude oil impacts on refining, and effects on fuel mix emission intensity and hydrotreating resulting from choices among carbon rejection and hydrogen addition technologies should be examined.

Several issues suggest future work. Other properties of crude feeds and incremental efficiencies from modernization of equipment and catalyst systems might explain up to 10% of the variability in *EI* observed among U.S. refining districts and years and could be more important for single plants and nondiverse crude feeds. Burning more fuel to refine lower quality oil emits toxic and ozone–precursor combustion products along with CO$_2$. Pastor et al. estimate that refinery emissions of such “co-pollutants” dominate health risk in nearby communities associated with particulate matter emitted by the largest industrial sources of greenhouse gases in California and identify racial disparities in this risk as important in emission assessment (*25*). Better facility-level *OQ* data could improve local-scale pollutant assessment. Better crude quality predictions could improve energy, and climate protection, forecasts. Assessments of the need, scope, and timing for transition to sustainable energy should account for emissions from lower quality oil.

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Supporting Information Available

Data and details of methods, analyses, and results. This material is available free of charge via the Internet at http://pubs.acs.org.

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Supporting information for the manuscript:

Combustion emissions from refining lower quality oil: What is the global warming potential?

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Supporting information given in the following 49 pages includes tables S1–S9, Figure S1, and references. Each table includes a legend and notes narrative that follows the values given, as does the figure. References identify sources of data cited. This information appears as follows:

Table S1

US		Refinery crude inputs[a]				Refinery process capacity[b]			
District	Year	Feed volume	Density	Sulfur	Source	Atm. dist.	Vacuum dist.	Coking & therm.	Cat. cracking
PADD		($m^3/d\bullet10^4$)	(kg/m^3)	(kg/m^3)	countries	($m^3/d\bullet10^4$)	($m^3/d\bullet10^4$)	($m^3/d\bullet10^4$)	($m^3/d\bullet10^4$)
1	1999	24.436	858.199	8.239	24	24.365	9.802	1.420	10.476
1	2000	24.754	860.182	8.000	23	24.592	9.721	1.440	10.798
1	2001	23.546	866.344	7.710	19	24.958	9.658	1.409	9.924
1	2002	24.246	865.708	7.445	20	25.222	9.742	1.442	9.899
1	2003	25.184	863.436	7.426	21	25.075	9.975	1.448	9.827
1	2004	24.961	865.443	7.789	21	25.025	9.974	1.448	9.827
1	2005	25.422	863.384	7.166	22	25.263	10.150	1.448	9.970
1	2006	23.626	864.122	7.172	21	25.263	10.149	1.448	9.970
1	2007	23.419	864.333	7.260	24	25.263	10.149	1.448	9.970
1	2008	22.115	863.647	7.082	24	25.263	10.149	1.448	9.970
2	1999	53.626	858.252	10.642	15	57.095	23.272	5.880	19.325
2	2000	54.215	860.025	11.352	16	56.984	23.625	6.098	19.189
2	2001	52.609	861.334	11.370	15	56.427	22.989	6.131	18.822
2	2002	51.162	861.019	11.279	20	55.775	22.592	5.698	18.688
2	2003	51.258	862.804	11.648	16	55.587	22.669	5.612	18.475
2	2004	52.482	865.655	11.859	20	55.528	22.961	5.818	18.268
2	2005	52.688	865.655	11.946	23	56.465	23.689	5.962	18.555
2	2006	52.609	865.443	11.597	20	56.506	23.895	5.948	18.538
2	2007	51.480	864.069	11.838	17	57.873	23.169	6.032	18.010
2	2008	51.575	862.594	11.731	16	57.980	23.466	5.923	18.676
3	1999	111.689	869.004	12.861	33	123.434	57.573	15.493	43.165
3	2000	113.024	870.287	12.967	31	123.436	59.107	16.498	43.434
3	2001	115.600	874.428	14.341	28	123.625	58.157	17.318	44.964
3	2002	112.786	876.703	14.466	33	125.817	57.449	18.717	46.010
3	2003	116.013	874.482	14.429	30	126.876	58.417	19.390	45.821
3	2004	119.145	877.791	14.396	33	128.032	60.442	20.047	46.126
3	2005	114.534	878.009	14.399	36	132.323	59.682	19.897	46.475
3	2006	117.253	875.673	14.361	41	133.383	59.850	20.190	46.632
3	2007	117.682	876.975	14.470	37	134.189	61.054	20.938	46.728
3	2008	111.879	878.663	14.937	36	133.771	61.411	21.046	47.311
5	1999	41.973	894.607	11.093	24	49.484	23.172	9.594	12.630
5	2000	43.086	895.853	10.840	23	49.836	23.152	9.714	12.717
5	2001	44.262	893.759	10.993	26	49.542	23.692	9.757	12.695
5	2002	44.787	889.993	10.858	27	48.422	23.419	9.834	12.768
5	2003	45.661	889.098	10.936	29	48.924	23.597	9.671	12.604
5	2004	45.486	888.874	11.200	28	48.723	23.478	9.695	12.717
5	2005	46.090	888.986	11.379	27	49.104	23.538	9.735	12.762
5	2006	45.693	887.648	10.918	30	49.441	23.930	9.759	13.026
5	2007	44.373	885.537	11.069	30	49.609	24.031	10.003	13.332
5	2008	44.739	890.161	12.106	30	49.730	24.411	9.793	13.170
4	1999	8.029	854.468	11.706	3	8.603	3.464	0.663	2.826
4	2000	8.156	859.346	12.031	2	8.094	3.130	0.663	2.705
4	2001	8.077	859.190	11.084	2	8.802	3.549	0.663	2.768
4	2002	8.363	860.234	12.043	2	9.054	3.616	0.676	2.898
4	2003	8.442	861.229	12.488	2	9.019	3.596	0.687	2.906
4	2004	8.856	862.594	11.645	2	9.296	4.255	0.695	2.950
4	2005	8.935	862.910	11.218	2	9.129	3.502	0.711	2.920
4	2006	8.856	860.496	11.359	2	10.018	3.560	0.711	3.121
4	2007	8.681	862.384	11.728	2	10.016	3.472	0.727	3.151
4	2008	8.585	863.120	12.170	2	9.555	3.305	0.989	2.832
US	1999	239.753	869.111	11.559	––	262.981	117.283	33.050	88.422
US	2000	243.235	870.822	11.669	––	262.942	118.735	34.413	88.844
US	2001	244.077	873.510	12.404	––	263.354	118.046	35.278	89.173
US	2002	241.343	873.888	12.322	––	264.289	116.819	36.368	90.263
US	2003	246.558	872.864	12.482	––	265.481	118.253	36.809	89.633
US	2004	250.930	875.185	12.515	––	266.604	121.109	37.703	89.887
US	2005	247.670	875.077	12.426	––	272.284	120.561	37.753	90.682
US	2006	248.052	873.780	12.320	––	274.612	121.385	38.056	91.286
US	2007	245.635	873.888	12.497	––	277.389	124.553	39.148	91.191
US	2008	238.910	875.023	12.863	––	276.299	122.742	39.198	91.959
Energy factor[c]		––	––	––	––	––	––	––	––
CO_2 emission factor (kg/GJ)[c]			––	––	––	––	––	––	––

Table S1 ***continued***

US		Refinery process capacity[b]							
District PADD	Year	Hydrocracking (m^3/d•10^4)	csHydrotreating (m^3/d•10^4)	psHydrotreating (m^3/d•10^4)	Reforming (m^3/d•10^4)	Alkylation (m^3/d•10^4)	Pol./Dim. (m^3/d•10^4)	Aromatics (m^3/d•10^4)	Isomerization (m^3/d•10^4)
1	1999	0.666	1.320	12.826	4.567	1.282	0.284	0.861	0.447
1	2000	0.666	1.320	12.460	4.468	1.346	0.284	0.852	0.431
1	2001	0.680	0.715	13.030	4.483	1.281	0.212	0.852	0.526
1	2002	0.602	2.131	12.214	4.528	1.292	0.212	0.852	0.611
1	2003	0.602	1.473	13.779	4.548	1.290	0.212	0.852	0.868
1	2004	0.603	1.477	13.513	4.649	1.290	0.212	0.852	0.878
1	2005	0.603	1.477	13.227	4.681	1.335	0.212	0.852	0.878
1	2006	0.615	0.704	13.993	4.681	1.335	0.212	0.852	0.878
1	2007	0.615	0.704	14.057	4.681	1.335	0.212	0.852	0.878
1	2008	0.615	0.704	14.057	4.681	1.335	0.212	0.852	0.878
2	1999	2.533	7.126	29.912	13.533	3.927	0.208	0.924	2.796
2	2000	2.533	6.099	31.548	13.770	3.959	0.208	0.924	2.764
2	2001	2.386	5.401	32.961	13.435	3.940	0.208	0.924	2.757
2	2002	2.434	7.177	31.440	13.357	3.892	0.136	0.888	2.698
2	2003	2.410	7.355	34.844	13.339	3.835	0.136	0.888	2.863
2	2004	2.191	8.214	35.157	13.247	3.807	0.129	0.876	2.900
2	2005	2.798	8.330	38.089	13.368	3.984	0.128	0.838	2.908
2	2006	3.065	7.937	39.013	13.347	3.991	0.128	0.919	2.940
2	2007	3.701	7.929	38.528	13.460	3.911	0.128	0.657	2.944
2	2008	3.652	8.440	36.890	12.972	3.871	0.130	0.657	2.784
3	1999	11.265	18.638	64.038	27.308	8.602	0.310	4.081	4.523
3	2000	11.513	19.190	65.900	27.730	8.599	0.297	4.202	4.347
3	2001	11.842	15.900	70.483	26.840	8.514	0.297	4.260	4.291
3	2002	12.138	18.588	70.415	27.234	9.806	0.353	4.310	4.551
3	2003	11.359	21.356	76.385	27.088	8.982	0.355	4.072	4.572
3	2004	11.868	22.256	82.382	27.517	10.514	0.378	4.386	4.472
3	2005	11.439	22.191	87.486	26.859	9.144	0.347	4.354	4.345
3	2006	11.447	22.301	90.603	26.857	9.253	0.345	4.239	4.312
3	2007	12.059	24.717	91.006	27.458	8.907	0.646	5.026	3.923
3	2008	11.843	22.910	94.039	27.091	9.179	0.646	5.786	4.284
5	1999	8.089	9.630	21.588	8.763	2.928	0.224	0.040	2.097
5	2000	8.119	8.347	22.626	8.849	4.181	0.234	0.040	2.142
5	2001	8.192	8.614	22.642	8.950	2.933	0.234	0.045	2.142
5	2002	8.192	9.472	21.821	8.833	2.999	0.234	0.045	2.147
5	2003	8.043	8.053	23.957	8.847	3.114	0.235	0.045	2.716
5	2004	8.138	8.151	24.765	8.895	3.119	0.238	0.040	2.659
5	2005	8.259	8.154	24.643	8.946	3.153	0.250	0.036	2.727
5	2006	8.896	7.932	25.742	9.400	3.359	0.280	0.021	2.937
5	2007	9.221	8.274	26.024	9.634	3.362	0.228	0.019	3.258
5	2008	9.124	8.123	26.175	9.473	3.337	0.228	0.019	3.171
4	1999	0.079	0.965	4.702	1.901	0.578	0.073	0.000	0.245
4	2000	0.079	0.744	4.368	1.770	0.525	0.067	0.000	0.245
4	2001	0.278	0.437	5.062	1.905	0.586	0.083	0.000	0.236
4	2002	0.079	0.783	4.784	1.889	0.612	0.083	0.000	0.236
4	2003	0.087	0.783	5.090	1.901	0.622	0.083	0.000	0.238
4	2004	0.254	0.836	4.673	1.772	0.566	0.076	0.000	0.239
4	2005	0.087	0.852	5.123	1.917	0.583	0.097	0.000	0.239
4	2006	0.254	1.092	5.444	1.940	0.596	0.097	0.000	0.258
4	2007	0.280	1.092	5.607	1.953	0.604	0.097	0.000	0.264
4	2008	0.087	1.302	5.720	1.816	0.612	0.083	0.000	0.264
US	1999	22.632	37.678	133.066	56.072	17.317	1.099	5.906	10.108
US	2000	22.910	35.699	136.901	56.585	18.609	1.090	6.017	9.929
US	2001	23.379	31.067	144.178	55.613	17.254	1.034	6.080	9.952
US	2002	23.446	38.151	140.674	55.840	18.602	1.018	6.093	10.243
US	2003	22.502	39.021	154.054	55.723	17.842	1.020	5.856	11.258
US	2004	23.054	40.935	160.490	56.081	19.295	1.034	6.154	11.148
US	2005	23.186	41.005	168.568	55.771	18.200	1.033	6.079	11.097
US	2006	24.278	39.967	174.794	56.226	18.534	1.062	6.032	11.324
US	2007	25.876	42.717	175.222	57.186	18.119	1.311	6.554	11.268
US	2008	25.322	41.479	176.881	56.034	18.333	1.299	7.314	11.381
Energy factor[c]		––	––	––	––	––	––	––	––
CO_2 emission factor (kg/GJ)[c]		––	––	––	––	––	––	––	––

Table S1 *continued*

US		Refinery process capacity[b] ———			———— Fuels consumed in refineries[a] ————				
District	Year	Lubes	Asphalt	Sulfur	H_2 production	Crude oil	LPG	Distillate	Res. fuel oil
PADD		($m^3/d \cdot 10^4$)	($m^3/d \cdot 10^4$)	($kg/d \cdot 10^6$)	($m^3 \cdot 10^8$)	($m^3 \cdot 10^4$)	($m^3 \cdot 10^4$)	($m^3 \cdot 10^4$)	($m^3 \cdot 10^4$)
1	1999	0.368	1.033	0.921	11.783	0.000	2.766	2.035	37.012
1	2000	0.300	0.461	0.921	14.056	0.000	5.008	4.165	38.904
1	2001	0.300	0.461	0.856	11.576	0.000	5.819	8.967	44.675
1	2002	0.299	0.445	1.265	10.232	0.000	4.483	7.631	29.190
1	2003	0.299	0.445	1.301	15.090	0.000	7.854	9.921	28.014
1	2004	0.300	0.445	1.301	15.090	0.000	7.870	7.409	18.013
1	2005	0.300	0.445	1.319	15.297	0.000	11.479	5.819	18.220
1	2006	0.300	0.445	1.319	17.364	0.000	5.231	0.366	14.627
1	2007	0.300	0.445	1.285	13.333	0.000	2.941	0.350	13.132
1	2008	0.300	0.445	1.285	13.333	0.000	0.827	0.461	6.344
2	1999	0.264	3.493	4.436	44.237	0.000	27.123	0.986	43.531
2	2000	0.264	3.763	4.402	44.030	0.000	14.484	0.763	34.166
2	2001	0.264	3.617	4.425	47.751	0.000	13.975	1.288	38.888
2	2002	0.277	3.668	4.672	43.926	0.000	16.439	1.081	29.747
2	2003	0.277	3.727	4.818	40.619	0.000	25.804	0.588	9.380
2	2004	0.277	3.705	4.631	41.032	0.000	17.155	0.588	3.100
2	2005	0.269	3.814	5.140	49.611	0.000	12.385	0.795	2.591
2	2006	0.269	3.897	5.243	77.000	0.000	9.015	0.715	3.275
2	2007	0.269	3.151	4.600	77.931	0.000	13.387	0.747	3.005
2	2008	0.135	3.608	5.200	78.551	0.000	12.783	0.700	3.084
3	1999	1.786	1.930	14.092	146.456	0.159	12.560	1.892	0.191
3	2000	1.801	1.967	15.297	148.833	0.000	13.085	2.798	0.032
3	2001	1.772	1.848	15.266	155.655	0.000	11.018	2.178	0.000
3	2002	1.745	1.904	16.516	160.512	0.000	13.450	1.335	0.000
3	2003	1.793	2.569	17.134	160.512	0.000	17.489	0.700	0.000
3	2004	1.982	2.409	19.395	174.362	0.000	5.898	1.304	0.000
3	2005	2.343	1.936	19.135	172.398	0.000	5.708	1.367	0.064
3	2006	2.351	1.914	19.393	162.269	0.000	4.404	1.765	0.016
3	2007	2.282	1.938	19.013	160.822	0.000	3.307	1.828	0.048
3	2008	2.281	1.938	19.243	164.233	0.000	8.204	1.701	0.048
5	1999	0.437	1.191	4.152	126.301	0.000	18.649	4.086	9.015
5	2000	0.437	1.215	4.152	151.934	0.000	34.150	3.736	11.081
5	2001	0.437	1.078	4.152	149.247	0.000	47.251	4.436	13.609
5	2002	0.342	0.742	4.230	151.004	0.000	19.587	3.307	14.341
5	2003	0.342	0.979	4.331	148.523	0.000	34.484	3.911	11.558
5	2004	0.286	0.920	4.286	147.903	0.000	24.627	3.657	11.495
5	2005	0.286	0.940	4.520	149.557	0.000	36.424	4.022	11.558
5	2006	0.318	0.916	4.911	159.169	0.000	23.339	4.054	12.242
5	2007	0.318	0.940	4.539	162.786	0.000	22.497	3.752	11.813
5	2008	0.318	0.940	5.011	162.786	0.000	23.991	4.642	11.845
4	1999	0.000	0.688	0.381	8.889	0.000	0.636	0.095	3.450
4	2000	0.000	0.671	0.382	8.992	0.000	0.890	0.048	4.786
4	2001	0.000	0.838	0.367	9.612	0.000	0.620	0.111	3.482
4	2002	0.000	0.738	0.368	9.612	0.000	0.700	0.000	3.259
4	2003	0.000	0.738	0.538	9.199	0.000	0.779	0.000	2.671
4	2004	0.000	0.743	0.612	9.509	0.000	1.065	0.016	2.337
4	2005	0.000	0.576	13.577	13.953	0.000	0.382	0.000	2.655
4	2006	0.000	0.796	0.593	13.953	0.000	0.238	0.000	1.924
4	2007	0.000	0.783	0.599	18.191	0.000	0.207	0.000	1.320
4	2008	0.000	0.807	0.595	20.878	0.000	0.779	0.000	0.779
US	1999	2.856	8.335	23.982	337.665	0.159	61.735	9.094	93.198
US	2000	2.803	8.077	25.154	367.845	0.000	67.617	11.511	88.969
US	2001	2.774	7.842	25.066	373.840	0.000	78.683	16.980	100.655
US	2002	2.662	7.498	27.051	375.287	0.000	54.660	13.355	76.536
US	2003	2.710	8.458	28.122	373.943	0.000	86.410	15.120	51.623
US	2004	2.845	8.222	30.225	387.896	0.000	56.615	12.973	34.945
US	2005	3.199	7.712	43.691	400.816	0.000	66.377	12.004	35.088
US	2006	3.239	7.967	31.459	429.756	0.000	42.227	6.900	32.084
US	2007	3.169	7.256	30.036	433.063	0.000	42.338	6.677	29.317
US	2008	3.035	7.737	31.334	439.781	0.000	46.583	7.504	22.099
Energy factor[c]		––	––	––	16.4 MJ/m^3	38.49 GJ/m^3	25.62 GJ/m^3	38.66 GJ/m^3	41.72 GJ/m^3
CO_2 emission factor (kg/GJ)[c]		––	––	––	52.70	78.53	65.76	77.18	83.14

Table S1 *continued*

US		Fuels consumed in refineries[a]						
District PADD	Year	Fuel gas (bl) ($m^3 \cdot 10^5$)	Pet. coke ($m^3 \cdot 10^5$)	Other product ($m^3 \cdot 10^4$)	Natural gas ($m^3 \cdot 10^8$)	Coal (Gg)	Electricity purchased (TWh)	Steam purchased (Tg)
1	1999	32.387	20.538	6.964	11.501	28.123	3.180	1.599
1	2000	31.990	19.093	6.105	12.553	27.216	3.084	1.897
1	2001	32.322	18.975	5.406	9.915	29.030	3.450	1.797
1	2002	33.987	18.805	5.851	11.086	28.123	3.282	1.865
1	2003	35.329	19.649	7.059	8.032	29.030	3.415	1.674
1	2004	35.419	20.377	2.242	9.177	26.308	3.410	2.352
1	2005	35.481	20.369	2.242	10.082	29.937	3.520	2.228
1	2006	33.756	17.541	0.859	10.258	28.123	3.576	2.593
1	2007	36.392	19.036	0.334	8.129	29.030	3.984	2.624
1	2008	33.909	19.393	0.461	7.892	28.123	4.192	2.360
2	1999	76.667	29.697	22.560	26.317	0.000	8.956	1.262
2	2000	77.341	29.335	19.047	30.038	1.814	8.949	0.890
2	2001	76.697	27.643	20.382	26.510	6.350	8.728	2.060
2	2002	73.293	27.689	19.555	27.235	0.000	8.933	2.368
2	2003	72.970	27.357	16.392	26.727	8.165	8.885	2.577
2	2004	79.249	25.339	27.855	29.254	7.257	9.486	2.863
2	2005	79.832	27.572	26.805	30.152	7.257	9.875	2.283
2	2006	78.834	26.236	31.177	32.485	2.722	10.488	3.310
2	2007	78.586	24.963	6.280	33.993	6.350	10.555	4.871
2	2008	77.716	23.856	0.286	39.330	10.886	10.804	4.999
3	1999	181.263	66.223	31.177	147.683	0.000	13.762	8.968
3	2000	184.163	67.454	34.405	147.541	0.000	14.501	11.455
3	2001	177.565	66.822	30.923	138.325	0.000	15.868	13.142
3	2002	181.193	66.891	21.479	129.876	0.000	16.145	14.670
3	2003	194.971	67.972	29.874	121.706	0.000	15.682	14.456
3	2004	190.864	69.595	22.544	111.896	0.000	17.044	14.827
3	2005	177.745	65.660	20.668	112.129	0.000	16.620	15.757
3	2006	198.807	72.481	31.336	112.029	0.000	18.612	17.690
3	2007	192.263	67.964	24.007	102.791	0.000	20.433	28.790
3	2008	181.956	62.598	26.996	107.893	0.000	20.675	28.919
5	1999	72.803	21.174	25.851	34.754	0.000	5.389	8.469
5	2000	74.282	22.314	26.185	38.268	0.000	4.809	8.268
5	2001	77.031	22.827	22.576	34.867	0.000	4.695	7.881
5	2002	70.694	22.640	22.672	38.733	0.000	4.780	7.589
5	2003	74.354	23.823	25.740	37.477	0.000	4.520	8.595
5	2004	73.964	24.441	31.305	35.335	0.000	4.871	8.732
5	2005	72.657	24.438	27.028	34.906	0.000	4.978	8.145
5	2006	71.543	23.133	34.961	35.733	0.000	4.973	8.164
5	2007	72.423	23.087	27.282	37.863	0.000	5.113	8.091
5	2008	68.973	19.651	32.227	39.629	0.000	5.125	8.064
4	1999	11.585	4.442	11.415	6.145	0.000	1.422	0.424
4	2000	11.465	4.153	13.132	5.502	0.000	1.486	0.384
4	2001	11.946	4.302	12.655	5.686	0.000	1.446	0.419
4	2002	11.639	4.262	13.260	6.024	0.000	1.581	0.337
4	2003	13.827	4.040	13.752	5.319	0.000	1.515	0.402
4	2004	13.541	4.372	8.649	5.472	0.000	1.583	0.504
4	2005	13.050	4.496	7.981	6.112	0.000	1.601	0.432
4	2006	13.508	4.480	2.258	7.031	0.000	1.704	0.343
4	2007	13.202	4.884	0.986	6.375	0.000	1.744	0.540
4	2008	14.501	4.571	1.081	6.445	0.000	1.886	0.458
US	1999	374.706	142.074	97.968	226.399	28.123	32.709	20.722
US	2000	379.240	142.348	98.874	233.902	29.030	32.829	22.894
US	2001	375.561	140.570	91.942	215.304	35.380	34.187	25.299
US	2002	370.806	140.287	82.816	212.953	28.123	34.721	26.830
US	2003	391.451	142.841	92.817	199.261	37.195	34.017	27.705
US	2004	393.037	144.125	92.594	191.134	33.566	36.394	29.278
US	2005	378.765	142.535	84.724	193.381	37.195	36.594	28.844
US	2006	396.448	143.871	100.591	197.536	30.844	39.353	32.100
US	2007	392.867	139.933	58.889	189.152	35.380	41.829	44.916
US	2008	377.056	130.069	61.051	201.191	39.009	42.682	44.801
Energy factor[c]		39.82 GJ/m^3	39.98 GJ/m^3	38.66 GJ/m^3	38.27 MJ/m^3	25.80 MJ/kg	3.6 MJ/kWh	2.18 MJ/kg
CO_2 emission factor (kg/GJ)[c]		67.73	107.74	73.20	55.98	99.58	187.78	91.63

Table S1 ***continued***

US District PADD	Year	Refinery product yields^a							
		LPG (%)	Fin. motor gasoline (%)	Aviation gasoline (%)	Kerosine jet fuel (%)	Kerosine (%)	Distillate fuel oil (%)	Residual fuel oil (%)	Naphtha for chem FS (%)
1	1999	2.5	46.6	0.2	7.0	0.8	26.3	6.5	0.8
1	2000	2.8	45.2	0.2	6.3	0.8	27.9	6.8	0.8
1	2001	2.9	45.8	0.2	5.3	0.8	29.1	6.6	0.8
1	2002	3.0	46.7	0.3	5.3	0.8	28.1	5.7	0.9
1	2003	3.0	46.4	0.2	5.2	0.8	27.2	7.8	0.8
1	2004	2.6	46.5	0.4	6.1	0.7	26.6	6.9	0.8
1	2005	2.4	46.6	0.3	5.7	0.7	28.8	6.2	0.8
1	2006	2.6	45.8		5.1	0.4	29.2	7.1	1.1
1	2007	3.2	45.5	0.1	5.0	0.5	29.4	7.2	1.1
1	2008	3.3	44.6		5.7	0.6	29.6	7.1	1.1
2	1999	3.7	51.1	0.1	6.6	0.5	24.8	1.6	0.6
2	2000	3.7	50.4	0.1	6.9	0.4	25.7	1.8	0.5
2	2001	3.6	51.1	0.1	6.6	0.4	26.0	2.0	0.6
2	2002	3.5	52.0	0.1	6.7	0.3	25.4	1.8	0.6
2	2003	3.3	51.5	0.1	6.2	0.3	26.0	1.7	0.5
2	2004	3.3	51.6	0.1	6.4	0.3	25.7	1.8	0.8
2	2005	3.1	50.4	0.1	6.5	0.3	27.1	1.6	0.8
2	2006	4.0	49.4	0.1	6.2	0.3	27.3	1.7	0.9
2	2007	3.9	49.8	0.1	6.1	0.1	28.2	1.7	0.9
2	2008	3.5	48.5	0.1	6.3	0.0	30.0	1.6	0.8
3	1999	6.1	44.8	0.2	11.1	0.4	21.1	4.3	2.1
3	2000	6.0	44.7	0.1	11.1	0.4	21.9	4.6	2.2
3	2001	5.6	44.3	0.1	10.5	0.6	22.8	4.8	1.7
3	2002	5.8	45.4	0.1	10.3	0.4	22.3	3.7	2.7
3	2003	5.5	44.8	0.1	9.9	0.4	23.0	4.1	2.6
3	2004	5.3	44.6	0.1	10.0	0.5	23.5	3.9	2.8
3	2005	4.7	43.8	0.1	10.2	0.6	24.5	3.9	2.3
3	2006	4.8	43.5	0.2	9.7	0.4	25.2	3.8	1.9
3	2007	5.0	43.2	0.1	9.4	0.3	26.0	4.1	1.9
3	2008	5.1	41.6	0.1	9.6	0.0	28.4	4.0	1.5
5	1999	2.6	44.7	0.1	15.8	0.2	18.3	8.5	0.2
5	2000	3.1	45.7	0.1	16.2	0.2	18.5	6.8	0.1
5	2001	2.7	45.5	0.1	16.0	0.1	19.2	6.9	0.1
5	2002	2.7	47.3	0.1	16.0	0.1	19.0	6.2	0.1
5	2003	2.9	47.2	0.1	16.0	0.0	19.5	5.8	0.1
5	2004	2.6	47.3	0.1	16.2	0.0	19.5	6.1	0.0
5	2005	2.5	47.3	0.1	16.2	0.0	20.4	5.8	0.0
5	2006	2.8	47.7	0.1	15.3	0.0	20.3	5.8	0.0
5	2007	2.8	46.6	0.1	15.6	0.0	20.8	6.3	0.0
5	2008	2.8	45.6	0.1	17.5	0.0	21.6	5.5	0.0
4	1999	1.3	47.8	0.1	5.4	0.5	28.7	2.3	
4	2000	1.3	47.1	0.1	5.8	0.3	29.1	2.0	0.0
4	2001	1.3	47.4	0.1	5.3	0.3	29.8	2.3	
4	2002	1.1	48.0	0.1	4.8	0.4	29.9	2.1	
4	2003	0.8	47.9	0.1	4.9	0.4	29.5	2.4	
4	2004	0.8	47.5	0.1	4.9	0.3	30.4	2.5	
4	2005	0.7	46.0	0.1	5.4	0.3	30.6	2.7	
4	2006	1.3	46.4	0.1	5.3	0.4	30.6	2.8	
4	2007	1.5	46.3	0.1	5.4	0.3	29.8	2.6	
4	2008	1.6	47.4	0.1	4.8	0.2	31.6	2.2	
US	1999	4.5	46.5	0.2	10.2	0.4	22.3	4.6	1.3
US	2000	4.5	46.2	0.1	10.3	0.4	23.1	4.5	1.3
US	2001	4.3	46.2	0.1	9.8	0.5	23.8	4.6	1.1
US	2002	4.3	47.3	0.1	9.8	0.4	23.2	3.9	1.6
US	2003	4.2	46.9	0.1	9.5	0.4	23.7	4.2	1.5
US	2004	4.0	46.8	0.1	9.7	0.4	23.9	4.1	1.6
US	2005	3.6	46.2	0.1	9.8	0.4	25.0	4.0	1.4
US	2006	3.9	45.8	0.1	9.3	0.3	25.4	4.0	1.2
US	2007	4.1	45.5	0.1	9.1	0.2	26.1	4.2	1.3
US	2008	4.1	44.2	0.1	9.7	0.1	27.8	4.0	1.0
Energy factor^c		––	––	––	––	––	––	––	––
CO_2 emission factor (kg/GJ)^c		––	––	––	––	––	––	––	––

Table S1 ***continued***

US		Refinery product yields[a]								Utilization of
District	Year	Oth. oils for	Special	Lubricants	Waxes	Petroleum	Asphalt &	Fuel gas	Miscellaneous	operable ref.
PADD		chem FS (%)	naphtha (%)	(%)	(%)	coke (%)	road oil (%)	(%)	products (%)	capacity[a] (%)
1	1999		0.1	1.0	0.0	3.1	5.4	3.7	0.1	90.9
1	2000		0.1	0.9	0.1	3.0	6.1	3.5	0.1	91.7
1	2001		0.1	0.9	0.0	3.3	6.0	3.8	0.1	87.2
1	2002		0.1	1.0	0.0	3.1	6.0	3.9	0.1	88.9
1	2003		0.1	1.0	0.0	2.9	5.7	3.8	0.1	92.7
1	2004		0.1	1.1	0.0	3.1	6.2	3.9	0.1	90.4
1	2005		0.1	1.0	0.0	2.9	5.7	3.8	0.1	93.1
1	2006		0.1	1.1	0.0	3.0	5.6	3.6	0.2	86.7
1	2007		0.0	1.0	0.0	3.2	5.0	3.9	0.2	85.6
1	2008		0.0	1.1	0.1	3.3	5.1	3.8	0.2	80.8
2	1999	0.7	0.7	0.6	0.1	4.2	5.6	3.9	0.3	93.3
2	2000	0.4	0.7	0.5	0.1	4.3	5.5	3.9	0.3	94.2
2	2001	0.0	0.6	0.4	0.1	4.3	5.1	4.0	0.3	93.9
2	2002	0.0	0.5	0.5	0.1	4.1	5.3	4.0	0.4	90.0
2	2003	0.0	0.6	0.5	0.1	4.2	5.6	4.1	0.4	91.6
2	2004	0.3	0.1	0.4	0.1	4.3	5.7	4.1	0.4	93.6
2	2005	0.3	0.2	0.4	0.1	4.5	5.7	4.1	0.5	92.9
2	2006	0.2	0.2	0.5	0.1	4.4	6.1	4.1	0.5	92.4
2	2007	0.2	0.1	0.4	0.1	4.3	5.3	4.2	0.4	90.1
2	2008	0.2	0.1	0.4	0.1	4.3	5.3	4.0	0.4	88.4
3	1999	2.5	0.8	1.7	0.2	4.8	1.7	4.1	0.4	94.7
3	2000	2.3	0.4	1.7	0.2	4.8	1.8	4.1	0.4	93.9
3	2001	2.1	0.4	1.6	0.1	5.3	1.6	4.1	0.5	94.8
3	2002	1.9	0.4	1.6	0.1	5.7	1.6	4.2	0.5	91.5
3	2003	2.3	0.4	1.5	0.1	5.7	1.6	4.4	0.5	93.6
3	2004	2.4	0.5	1.6	0.1	5.9	1.5	4.3	0.4	94.1
3	2005	2.1	0.4	1.6	0.1	6.0	1.6	4.3	0.4	88.3
3	2006	2.4	0.4	1.7	0.1	6.2	1.5	4.6	0.5	88.7
3	2007	2.4	0.5	1.7	0.1	6.0	1.3	4.3	0.5	88.7
3	2008	2.3	0.5	1.7	0.1	6.0	1.1	4.4	0.6	83.6
5	1999	0.3	0.1	1.0	0.0	6.1	2.4	5.8	0.2	87.1
5	2000	0.3	0.1	0.9	-0.1	6.3	2.4	5.6	0.3	87.5
5	2001	0.3	0.1	1.0	0.0	6.0	2.1	5.8	0.3	89.1
5	2002	0.3	0.1	0.8	0.0	6.0	2.1	5.5	0.3	90.0
5	2003	0.3	0.1	0.8		6.2	1.9	5.6	0.3	91.3
5	2004	0.3	0.0	0.7		6.1	1.9	5.4	0.3	90.4
5	2005	0.4	0.0	0.7		6.2	1.7	5.1	0.3	91.7
5	2006	0.4	0.1	0.7		6.0	1.8	5.2	0.4	90.5
5	2007	0.3	0.0	0.6		5.8	1.8	5.4	0.4	87.6
5	2008	0.1	0.0	0.8		6.1	1.4	5.1	0.5	88.1
4	1999	0.1	0.0		0.7	3.4	8.8	4.1	0.4	95.7
4	2000	0.1	0.0		0.6	3.3	9.3	3.9	0.4	94.7
4	2001	0.2	0.0		0.6	3.3	8.6	4.1	0.4	90.7
4	2002	0.1			0.5	3.2	9.2	3.8	0.4	91.6
4	2003	0.1			0.4	3.2	9.1	4.5	0.4	91.9
4	2004	0.1			0.4	3.2	9.3	4.2	0.4	95.7
4	2005	0.1	0.0		0.4	3.3	9.5	4.1	0.4	95.5
4	2006	0.1	0.0		0.3	3.3	8.5	4.2	0.4	93.5
4	2007	0.1	0.0		0.0	3.4	8.9	4.2	0.3	91.3
4	2008		0.0		0.0	4.6	6.1	4.6	0.5	89.4
US	1999	1.4	0.6	1.2	0.1	4.7	3.3	4.3	0.3	92.6
US	2000	1.3	0.4	1.2	0.1	4.7	3.4	4.2	0.4	92.6
US	2001	1.1	0.3	1.1	0.1	4.9	3.1	4.3	0.4	92.6
US	2002	1.0	0.3	1.1	0.1	5.1	3.2	4.3	0.4	90.7
US	2003	1.2	0.3	1.1	0.1	5.1	3.2	4.5	0.4	92.6
US	2004	1.3	0.3	1.1	0.1	5.2	3.2	4.4	0.4	93.0
US	2005	1.1	0.2	1.1	0.1	5.3	3.2	4.3	0.4	90.6
US	2006	1.2	0.2	1.2	0.1	5.3	3.2	4.5	0.4	89.7
US	2007	1.3	0.3	1.1	0.1	5.2	2.9	4.4	0.4	88.5
US	2008	1.2	0.3	1.1	0.1	5.3	2.7	4.3	0.5	85.3
Energy factor[c]		––	––	––	––	––	––	––	––	––
CO_2 emission factor (kg/GJ)[c]		––	––	––	––	––	––	––	––	––

Table S1 ***continued***

Energy consumed/volume crude feed (GJ/m^3) and CO_2 emitted/vol. crude feed (kg/m^3) for refinery fuels[c]

US District PADD	Year	Hydrogen prod.		Crude oil consmd.		LPG consumed		Distillate consmd.		Res. fuel oil cons.		Fuel gas (bl)	
		(GJ/m^3)	(kg/m^3)	(GJ/m^3)	(kg/m^3)	(GJ/m^3)	(kg/m^3)	(GJ/m^3)	(kg/m^3)	(GJ/m^3)	(kg/m^3)	(GJ/m^3)	(kg/m^3)
1	1999	0.195	10.28	0.000	0.00	0.008	0.52	0.009	0.68	0.173	14.39	1.446	97.93
1	2000	0.230	12.10	0.000	0.00	0.014	0.93	0.018	1.38	0.180	14.94	1.410	95.49
1	2001	0.199	10.48	0.000	0.00	0.017	1.14	0.040	3.11	0.217	18.03	1.498	101.43
1	2002	0.171	8.99	0.000	0.00	0.013	0.85	0.033	2.57	0.138	11.44	1.529	103.58
1	2003	0.242	12.77	0.000	0.00	0.022	1.44	0.042	3.22	0.127	10.57	1.530	103.66
1	2004	0.244	12.88	0.000	0.00	0.022	1.46	0.031	2.43	0.082	6.86	1.548	104.85
1	2005	0.243	12.82	0.000	0.00	0.032	2.08	0.024	1.87	0.082	6.81	1.523	103.13
1	2006	0.297	15.66	0.000	0.00	0.016	1.02	0.002	0.13	0.071	5.88	1.559	105.58
1	2007	0.230	12.13	0.000	0.00	0.009	0.58	0.002	0.12	0.064	5.33	1.695	114.82
1	2008	0.244	12.85	0.000	0.00	0.003	0.17	0.002	0.17	0.033	2.73	1.673	113.30
2	1999	0.334	17.58	0.000	0.00	0.036	2.33	0.002	0.15	0.093	7.71	1.560	105.64
2	2000	0.328	17.31	0.000	0.00	0.019	1.23	0.001	0.12	0.072	5.99	1.556	105.41
2	2001	0.367	19.34	0.000	0.00	0.019	1.23	0.003	0.20	0.084	7.02	1.590	107.72
2	2002	0.347	18.30	0.000	0.00	0.023	1.48	0.002	0.17	0.066	5.53	1.563	105.85
2	2003	0.320	16.89	0.000	0.00	0.035	2.32	0.001	0.09	0.021	1.74	1.553	105.19
2	2004	0.316	16.66	0.000	0.00	0.023	1.51	0.001	0.09	0.007	0.56	1.647	111.58
2	2005	0.381	20.07	0.000	0.00	0.016	1.09	0.002	0.12	0.006	0.47	1.653	111.96
2	2006	0.592	31.19	0.000	0.00	0.012	0.79	0.001	0.11	0.007	0.59	1.635	110.72
2	2007	0.612	32.26	0.000	0.00	0.018	1.20	0.002	0.12	0.007	0.55	1.665	112.80
2	2008	0.616	32.46	0.000	0.00	0.017	1.14	0.001	0.11	0.007	0.57	1.644	111.34
3	1999	0.530	27.94	0.000	0.01	0.008	0.52	0.002	0.14	0.000	0.02	1.771	119.92
3	2000	0.533	28.06	0.000	0.00	0.008	0.53	0.003	0.20	0.000	0.00	1.778	120.40
3	2001	0.545	28.70	0.000	0.00	0.007	0.44	0.002	0.15	0.000	0.00	1.676	113.50
3	2002	0.576	30.33	0.000	0.00	0.008	0.55	0.001	0.10	0.000	0.00	1.753	118.71
3	2003	0.559	29.49	0.000	0.00	0.011	0.70	0.001	0.05	0.000	0.00	1.833	124.18
3	2004	0.592	31.19	0.000	0.00	0.003	0.23	0.001	0.09	0.000	0.00	1.748	118.37
3	2005	0.609	32.08	0.000	0.00	0.003	0.23	0.001	0.10	0.000	0.01	1.693	114.67
3	2006	0.560	29.49	0.000	0.00	0.003	0.17	0.002	0.12	0.000	0.00	1.850	125.28
3	2007	0.553	29.12	0.000	0.00	0.002	0.13	0.002	0.13	0.000	0.00	1.782	120.72
3	2008	0.594	31.28	0.000	0.00	0.005	0.34	0.002	0.12	0.000	0.00	1.774	120.17
5	1999	1.217	64.13	0.000	0.00	0.031	2.05	0.010	0.80	0.025	2.04	1.892	128.17
5	2000	1.426	75.15	0.000	0.00	0.056	3.66	0.009	0.71	0.029	2.44	1.881	127.39
5	2001	1.364	71.86	0.000	0.00	0.075	4.93	0.011	0.82	0.035	2.92	1.899	128.59
5	2002	1.363	71.85	0.000	0.00	0.031	2.02	0.008	0.60	0.037	3.04	1.722	116.63
5	2003	1.315	69.32	0.000	0.00	0.053	3.49	0.009	0.70	0.029	2.41	1.776	120.32
5	2004	1.315	69.29	0.000	0.00	0.038	2.50	0.009	0.66	0.029	2.40	1.774	120.15
5	2005	1.312	69.15	0.000	0.00	0.055	3.65	0.009	0.71	0.029	2.38	1.720	116.48
5	2006	1.409	74.24	0.000	0.00	0.036	2.36	0.009	0.73	0.031	2.55	1.708	115.69
5	2007	1.484	78.18	0.000	0.00	0.036	2.34	0.009	0.69	0.030	2.53	1.781	120.60
5	2008	1.471	77.54	0.000	0.00	0.038	2.48	0.011	0.85	0.030	2.52	1.682	113.92
4	1999	0.448	23.59	0.000	0.00	0.006	0.37	0.001	0.10	0.049	4.08	1.574	106.62
4	2000	0.446	23.50	0.000	0.00	0.008	0.50	0.001	0.05	0.067	5.58	1.534	103.86
4	2001	0.481	25.36	0.000	0.00	0.005	0.35	0.001	0.11	0.049	4.10	1.614	109.29
4	2002	0.465	24.49	0.000	0.00	0.006	0.39	0.000	0.00	0.045	3.70	1.518	102.84
4	2003	0.441	23.22	0.000	0.00	0.006	0.43	0.000	0.00	0.036	3.01	1.787	121.02
4	2004	0.434	22.88	0.000	0.00	0.008	0.56	0.000	0.01	0.030	2.51	1.668	112.99
4	2005	0.631	33.28	0.000	0.00	0.003	0.20	0.000	0.00	0.034	2.82	1.593	107.92
4	2006	0.637	33.58	0.000	0.00	0.002	0.12	0.000	0.00	0.025	2.06	1.664	112.71
4	2007	0.847	44.66	0.000	0.00	0.002	0.11	0.000	0.00	0.017	1.44	1.659	112.38
4	2008	0.983	51.82	0.000	0.00	0.006	0.42	0.000	0.00	0.010	0.86	1.843	124.81
US	1999	0.570	30.01	0.000	0.01	0.018	1.19	0.004	0.31	0.044	3.69	1.705	115.48
US	2000	0.612	32.23	0.000	0.00	0.020	1.28	0.005	0.39	0.042	3.48	1.701	115.21
US	2001	0.619	32.64	0.000	0.00	0.023	1.49	0.007	0.57	0.047	3.92	1.679	113.70
US	2002	0.629	33.14	0.000	0.00	0.016	1.05	0.006	0.45	0.036	3.01	1.676	113.53
US	2003	0.613	32.32	0.000	0.00	0.025	1.62	0.006	0.50	0.024	1.99	1.732	117.31
US	2004	0.625	32.94	0.000	0.00	0.016	1.04	0.005	0.42	0.016	1.32	1.709	115.74
US	2005	0.654	34.49	0.000	0.00	0.019	1.24	0.005	0.40	0.016	1.35	1.668	113.00
US	2006	0.701	36.92	0.000	0.00	0.012	0.79	0.003	0.23	0.015	1.23	1.744	118.10
US	2007	0.713	37.57	0.000	0.00	0.012	0.80	0.003	0.22	0.014	1.13	1.745	118.18
US	2008	0.744	39.23	0.000	0.00	0.014	0.90	0.003	0.26	0.011	0.88	1.722	116.62
Energy factor[c]		16.4 MJ/m^3		38.49 GJ/m^3		25.62 GJ/m^3		38.66 GJ/m^3		41.72 GJ/m^3		39.82 GJ/m^3	
CO_2 emission factor (kg/GJ)[c]		––	52.70	––	78.53	––	65.76	––	77.18	––	83.14	––	67.73

Table S1 ***continued***

US Energy consumed/volume crude feed (GJ/m^3) and CO_2 emitted/vol. crude feed (kg/m^3) for refinery fuels[c]

US District PADD	Year	Petroleum coke		Other products		Natural gas		Coal consumed		Electricity purch.		Steam purch.	
		(GJ/m^3)	(kg/m^3)	(GJ/m^3)	(kg/m^3)	(GJ/m^3)	(kg/m^3)	(GJ/m^3)	(kg/m^3)	(GJ/m^3)	(kg/m^3)	(GJ/m^3)	(kg/m^3)
1	1999	0.921	99.186	0.030	2.21	0.493	27.63	0.008	0.81	0.128	24.10	0.039	3.58
1	2000	0.845	91.022	0.026	1.91	0.532	29.76	0.008	0.77	0.123	23.07	0.046	4.19
1	2001	0.883	95.103	0.024	1.78	0.442	24.72	0.009	0.87	0.145	27.14	0.046	4.18
1	2002	0.850	91.531	0.026	1.87	0.479	26.84	0.008	0.82	0.134	25.07	0.046	4.21
1	2003	0.855	92.078	0.030	2.17	0.334	18.72	0.008	0.81	0.134	25.11	0.040	3.64
1	2004	0.894	96.342	0.010	0.70	0.386	21.58	0.007	0.74	0.135	25.30	0.056	5.16
1	2005	0.878	94.557	0.009	0.68	0.416	23.28	0.008	0.83	0.137	25.64	0.052	4.80
1	2006	0.813	87.620	0.004	0.28	0.455	25.48	0.008	0.84	0.149	28.03	0.066	6.01
1	2007	0.890	95.924	0.002	0.11	0.364	20.37	0.009	0.87	0.168	31.51	0.067	6.13
1	2008	0.961	103.488	0.002	0.16	0.374	20.95	0.009	0.90	0.187	35.11	0.064	5.84
2	1999	0.607	65.353	0.045	3.26	0.515	28.80	0.000	0.00	0.165	30.93	0.014	1.29
2	2000	0.593	63.855	0.037	2.72	0.581	32.52	0.000	0.02	0.163	30.57	0.010	0.90
2	2001	0.576	62.009	0.041	3.00	0.528	29.58	0.001	0.08	0.164	30.73	0.023	2.14
2	2002	0.593	63.869	0.040	2.96	0.558	31.24	0.000	0.00	0.172	32.34	0.028	2.53
2	2003	0.585	62.985	0.034	2.48	0.547	30.60	0.001	0.11	0.171	32.10	0.030	2.75
2	2004	0.529	56.979	0.056	4.11	0.584	32.72	0.001	0.10	0.178	33.48	0.033	2.99
2	2005	0.573	61.755	0.054	3.94	0.600	33.59	0.001	0.10	0.185	34.71	0.026	2.37
2	2006	0.546	58.853	0.063	4.59	0.647	36.24	0.000	0.04	0.197	36.92	0.038	3.44
2	2007	0.531	57.224	0.013	0.95	0.692	38.76	0.001	0.09	0.202	37.97	0.057	5.18
2	2008	0.507	54.586	0.001	0.04	0.800	44.76	0.001	0.15	0.207	38.80	0.058	5.30
3	1999	0.649	69.972	0.030	2.16	1.386	77.61	0.000	0.00	0.122	22.82	0.048	4.39
3	2000	0.654	70.430	0.032	2.36	1.369	76.62	0.000	0.00	0.127	23.76	0.061	5.55
3	2001	0.633	68.217	0.028	2.07	1.255	70.23	0.000	0.00	0.135	25.42	0.068	6.22
3	2002	0.650	69.991	0.020	1.48	1.207	67.59	0.000	0.00	0.141	26.51	0.078	7.12
3	2003	0.642	69.143	0.027	2.00	1.100	61.57	0.000	0.00	0.133	25.04	0.074	6.82
3	2004	0.640	68.933	0.020	1.47	0.985	55.12	0.000	0.00	0.141	26.49	0.074	6.81
3	2005	0.628	67.654	0.019	1.40	1.026	57.46	0.000	0.00	0.143	26.88	0.082	7.53
3	2006	0.677	72.950	0.028	2.07	1.002	56.08	0.000	0.00	0.157	29.40	0.090	8.26
3	2007	0.633	68.154	0.022	1.58	0.916	51.27	0.000	0.00	0.171	32.16	0.146	13.39
3	2008	0.613	66.029	0.026	1.87	1.011	56.60	0.000	0.00	0.182	34.23	0.154	14.15
5	1999	0.553	59.534	0.065	4.78	0.868	48.60	0.000	0.00	0.127	23.78	0.121	11.04
5	2000	0.567	61.118	0.064	4.71	0.931	52.13	0.000	0.00	0.110	20.67	0.115	10.50
5	2001	0.565	60.863	0.054	3.95	0.826	46.24	0.000	0.00	0.105	19.65	0.106	9.74
5	2002	0.554	59.655	0.054	3.92	0.907	50.76	0.000	0.00	0.105	19.77	0.101	9.27
5	2003	0.571	61.570	0.060	4.37	0.861	48.17	0.000	0.00	0.098	18.33	0.112	10.30
5	2004	0.589	63.411	0.073	5.34	0.814	45.60	0.000	0.00	0.106	19.83	0.115	10.51
5	2005	0.581	62.572	0.062	4.55	0.794	44.45	0.000	0.00	0.107	20.00	0.106	9.67
5	2006	0.555	59.745	0.081	5.93	0.820	45.90	0.000	0.00	0.107	20.16	0.107	9.78
5	2007	0.570	61.399	0.065	4.77	0.895	50.08	0.000	0.00	0.114	21.34	0.109	9.98
5	2008	0.481	51.835	0.076	5.58	0.929	51.99	0.000	0.00	0.113	21.22	0.108	9.86
4	1999	0.606	65.292	0.151	11.02	0.802	44.92	0.000	0.00	0.175	32.80	0.032	2.89
4	2000	0.558	60.087	0.171	12.48	0.707	39.60	0.000	0.00	0.180	33.74	0.028	2.57
4	2001	0.583	62.862	0.166	12.15	0.738	41.32	0.000	0.00	0.177	33.16	0.031	2.84
4	2002	0.558	60.150	0.168	12.29	0.755	42.28	0.000	0.00	0.186	35.01	0.024	2.21
4	2003	0.524	56.473	0.173	12.63	0.661	36.98	0.000	0.00	0.177	33.24	0.028	2.61
4	2004	0.541	58.265	0.103	7.57	0.648	36.27	0.000	0.00	0.176	33.11	0.034	3.12
4	2005	0.551	59.384	0.095	6.93	0.717	40.15	0.000	0.00	0.177	33.19	0.029	2.64
4	2006	0.554	59.705	0.027	1.98	0.832	46.60	0.000	0.00	0.190	35.64	0.023	2.12
4	2007	0.616	66.398	0.012	0.88	0.770	43.10	0.000	0.00	0.198	37.21	0.037	3.41
4	2008	0.583	62.831	0.013	0.98	0.787	44.07	0.000	0.00	0.217	40.69	0.032	2.92
US	1999	0.649	69.932	0.043	3.17	0.990	55.43	0.001	0.08	0.135	25.27	0.052	4.73
US	2000	0.641	69.064	0.043	3.15	1.008	56.44	0.001	0.08	0.133	25.00	0.056	5.15
US	2001	0.631	67.966	0.040	2.92	0.925	51.78	0.001	0.10	0.138	25.94	0.062	5.67
US	2002	0.637	68.598	0.036	2.66	0.925	51.79	0.001	0.08	0.142	26.65	0.066	6.08
US	2003	0.635	68.369	0.040	2.92	0.847	47.44	0.001	0.11	0.136	25.55	0.067	6.15
US	2004	0.629	67.782	0.039	2.86	0.799	44.71	0.001	0.09	0.143	26.86	0.070	6.39
US	2005	0.630	67.916	0.036	2.65	0.819	45.83	0.001	0.11	0.146	27.36	0.070	6.37
US	2006	0.635	68.447	0.043	3.14	0.835	46.74	0.001	0.09	0.156	29.38	0.077	7.08
US	2007	0.624	67.229	0.025	1.86	0.807	45.20	0.001	0.10	0.168	31.54	0.109	10.01
US	2008	0.596	64.249	0.027	1.98	0.883	49.43	0.001	0.11	0.176	33.09	0.112	10.26
Energy factor[c]		39.98 GJ/m^3		38.66 GJ/m^3		38.27 MJ/m^3		25.80 MJ/kg		3.60 MJ/kWh		2.18 MJ/kg	
CO_2 emission factor (kg/GJ)[c]		––	107.74	––	73.20	––	55.98	––	99.58	––	187.78	––	91.63

Table S1 ***continued***

US District PADD	Year	Refinery energy consumed *(EI)*[d] (GJ/m^3)	Fuel mix emission intensity (CO_2)[d] (kg/GJ)	Refinery carbon dioxide emissions[d] (kg/m^3)
1	1999	3.451	81.53	281.3
1	2000	3.430	80.34	275.6
1	2001	3.518	81.85	288.0
1	2002	3.426	81.08	277.8
1	2003	3.364	81.51	274.2
1	2004	3.416	81.46	278.3
1	2005	3.404	81.23	276.5
1	2006	3.440	80.40	276.5
1	2007	3.499	82.28	287.9
1	2008	3.551	83.26	295.7
2	1999	3.368	78.10	263.1
2	2000	3.361	77.56	260.6
2	2001	3.396	77.46	263.1
2	2002	3.393	77.90	264.3
2	2003	3.298	78.00	257.3
2	2004	3.376	77.25	260.8
2	2005	3.496	77.27	270.2
2	2006	3.738	75.84	283.5
2	2007	3.800	75.55	287.1
2	2008	3.858	74.97	289.3
3	1999	4.546	71.61	325.5
3	2000	4.563	71.87	327.9
3	2001	4.348	72.43	315.0
3	2002	4.434	72.71	322.4
3	2003	4.381	72.81	319.0
3	2004	4.204	73.43	308.7
3	2005	4.205	73.24	308.0
3	2006	4.367	74.15	323.8
3	2007	4.226	74.93	316.7
3	2008	4.361	74.48	324.8
5	1999	4.908	70.27	344.9
5	2000	5.189	69.09	358.5
5	2001	5.039	69.38	349.6
5	2002	4.881	69.15	337.5
5	2003	4.885	69.40	339.0
5	2004	4.861	69.89	339.7
5	2005	4.774	69.88	333.6
5	2006	4.862	69.32	337.1
5	2007	5.091	69.12	351.9
5	2008	4.939	68.39	337.8
4	1999	3.843	75.90	291.7
4	2000	3.698	76.25	282.0
4	2001	3.846	75.80	291.6
4	2002	3.726	76.06	283.4
4	2003	3.833	75.56	289.6
4	2004	3.644	76.10	277.3
4	2005	3.830	74.80	286.5
4	2006	3.955	74.48	294.5
4	2007	4.159	74.43	309.6
4	2008	4.475	73.61	329.4
US	1999	4.211	73.46	309.3
US	2000	4.261	73.09	311.5
US	2001	4.172	73.51	306.7
US	2002	4.170	73.62	307.0
US	2003	4.126	73.74	304.3
US	2004	4.052	74.08	300.2
US	2005	4.065	73.98	300.7
US	2006	4.222	73.94	312.1
US	2007	4.221	74.34	313.8
US	2008	4.289	73.90	317.0
Energy factor[c]		––	––	––
CO_2 emission factor (kg/GJ)[c]		––	––	––

Legend and notes for Table S1.

Observations of operating refineries that support the central analysis reported in the main text are based on the data given in Table S1.

a. Refinery crude inputs, fuels consumed, products yield, and capacity utilization are from the U.S. Energy Information Administration (USEIA) *(S1-6).* Fuel energy consumption for hydrogen production is discussed below. Blank entries for yield of some minor products in some districts and years were blank in the original data reported *(S5)* and were assigned a value of zero in the analysis.

b. Process capacities are volumes that can be processed during 24 hours after making allowances for types and grades of inputs and products, environmental constraints and scheduled downtime, from *Oil & Gas Journal (S7).* The prefix “cs” or “ps” denotes processing of crude streams (including gas oil and residua) or of product streams, respectively (csHydrotreating thus includes hydrotreating of gas oil, residua and catalytic cracking feeds). Atmospheric and vacuum distillation capacities reported for the BP Ferndale, WA, and Carson, CA, refineries in 2007 are higher than those in 2006 or 2008 although no distillation upgrades are reported at those plants in 2006 or 2007, and reported vacuum distillation capacity exceeded total crude capacity reported at the Ferndale plant *(S7).* The reported data for those four entries are replaced by the average of 2006 and 2008 atmospheric, and vacuum distillation, capacities for each of those two plants. This results in $49.609 \bullet 10^4$ instead of $50.047 \bullet 10^4$ m^3/day for atmospheric distillation, and $24.031 \bullet 10^4$ instead of $26.709 \bullet 10^4$ m^3/day for vacuum distillation, in those District 5 entries shown for 2007. Analyses including the reported data, including the corrected data, and excluding the observation (for District 5 in 2007), showed that this correction did not affect the results significantly.

c. Contributions of refinery fuels to refinery energy consumption/m^3 crude feed (GJ/m^3) and refinery mass emissions of CO_2 (kg/m^3 crude feed) are shown. These contributions are calculated using the fuel consumption reported and the energy and emission factors shown below each fuel in the table. The energy factor for hydrogen is for an efficient natural gas-fueled steam methane reforming unit as discussed below. Steam energy is based on latent heat of evaporation at 153 kPa/126 ºC. All other factors for conversions to common energy units (HHV) are from the California Air Resources Board *(S8).* Emission factors (except for H_2 production) are the fuel emission factors for CO_2 emission from stationary combustion established by USEIA for its voluntary reporting of greenhouse gases program *(S9).* These emission factors are based on carbon content and oxidation estimates for U.S. fuels quality that the agency derived and documented for its estimates of greenhouse gas emissions in the U.S. *(S10).* The U.S. grid average factor is applied to purchased electricity. The average of distillate, LPG, and waste oil blended with distillate fuel factors is applied to the “other products” category.

Energy consumed by hydrogen production cannot be calculated from the USEIA fuels data *(S11, S12).* However, the strong trend of hydroprocessing and hydrogen plant capacity addition shown in Table S1 suggests that U.S. refineries were generally hydrogen-limited, and used most of their available H_2 capacity, during 1999-2008. Energy requirements are assigned to 90% of the hydrogen production capacity reported *(S7)* for these reasons. Energy use for steam reforming of natural gas ranges by approximately 15-18 MJ/m^3 H_2 produced *(S12-15),* and is greater for less efficient designs and for plants using heavier feeds such as naphtha. The energy factor used here (16.4 MJ/m^3) is for a modern steam methane reformer using pressure swing absorption and natural gas feed *(S13).* The CO_2 emissions factor (52.7 kg/GJ) is derived from the same source *(S13)* and is virtually identical to USEPA's estimate of 0.053 t/MM Btu *(S15).* Steam reformer CO_2 emissions are primarily from the shift reaction rather than direct combustion, and increase with the use of heavier feeds and less efficient hydrogen production methods *(S12, S15).* Because many refinery hydrogen plants use less efficient technology, naphtha feed or both, the factors used are conservative.

d. Refinery energy intensity (*EI*) (GJ/m^3 crude feed), fuel mix emission intensity (kg/GJ), and emissions (kg/m^3) are shown in the last three columns of the table. *EI* ranges by 57%, from 3.30 to 5.19 GJ/m^3 crude feed, while fuel mix emission intensity ranges from 68.4 to 83.3 kg/GJ (22%) among districts and years. The much larger percentage range for *EI* indicates that differences in total amounts of fuel energy used per volume crude processed have a greater impact on total emissions than differences in the emission intensity of the fuel mix, for these districts and years.

Fuel gas, natural gas, petroleum coke and hydrogen (assumed to be natural gas-fueled herein) account for the vast majority of energy and emissions in all cases but the fuel mix varies between districts and years. Fuel gas accounts for 34% of total energy and emissions in District 5 during 2008, but it accounts for 49% of total energy and 43% of total emissions in District 2 during 2004. Natural gas excluding H_2 production accounts for 10% of energy and 7% of emissions in District 1 during 2003 but 30% of energy and 24% of emissions in District 3 during 1999. Hydrogen accounts for 5% of energy and 3% of emissions in District 1 during 2002, but 30% of energy and 23% of emissions in District 5 during 2008.

Petroleum coke accounts for 10% of energy and 15% of emissions in District 5 during 2008, but it accounts for 27% of energy and 35% of emissions in District 1 during both 1999 and 2008.

Fuel mix emission intensity generally increases with the portion of fuel mix emissions accounted for by coke, which increases with the catalytic cracking/ atmospheric distillation ratio, among districts and years. Petroleum coke is a byproduct of cracking reactions that is burned in cracking catalyst regeneration. Catalytic cracking generally decreases with increasing hydrocracking (capacities/atm. capacity). At the same time, hydrogen production capacity increases with hydrocracking capacity, and with crude feed density. (Other variables also relate to crude density and sulfur content as described in the main text.) Although it varies much less than *EI,* fuel mix emission intensity decreases as *EI,* crude feed density, and crude feed sulfur content increase, among these districts and years.

Table S2. Simplified mixing analysis for potential effects of anomalous oils on crude feeds.

		Refinery crude feed volume data reported[a]				Anomalous oil assumption[c]		Potential crude feed effect[d]	
		Potentially anomalous streams[b]							
PADD	Year	Stream 1 (% vol.)	Stream 2 (% vol.)	Stream 3 (% vol.)	Other streams (% vol.)	Predicted by density, sulfur (factor)	Excess in anomalous oil (factor)	Crude feed predicted (factor)	Crude feed with anomaly (factor)
1	1999	16.59	14.62	10.82	57.97	1	2	1.00	1.27
1	2000	19.73	11.91	11.51	56.85	1	2	1.00	1.29
1	2001	20.49	12.87	11.51	55.13	1	2	1.00	1.30
1	2002	17.28	12.96	12.32	57.44	1	2	1.00	1.27
1	2003	21.93	14.15	13.46	50.46	1	2	1.00	1.32
1	2004	27.74	12.61	11.06	48.59	1	2	1.00	1.37
1	2005	29.46	13.42	11.68	45.44	1	2	1.00	1.39
1	2006	29.89	14.12	12.27	43.72	1	2	1.00	1.40
1	2007	26.88	17.86	11.21	44.05	1	2	1.00	1.39
1	2008	23.23	18.71	10.97	47.09	1	2	1.00	1.35
2	1999	24.01	5.50	4.49	66.00	1	2	1.00	1.28
2	2000	26.90	5.78	4.00	63.32	1	2	1.00	1.31
2	2001	29.08	5.84	3.33	61.75	1	2	1.00	1.33
2	2002	29.40	5.50	1.93	63.17	1	2	1.00	1.33
2	2003	30.82	5.57	2.52	61.09	1	2	1.00	1.34
2	2004	32.02	4.66	2.26	61.06	1	2	1.00	1.35
2	2005	31.35	3.99	2.46	62.20	1	2	1.00	1.34
2	2006	34.76	4.83	1.63	58.78	1	2	1.00	1.38
2	2007	34.73	4.97	2.17	58.13	1	2	1.00	1.38
2	2008	36.35	4.52	1.94	57.19	1	2	1.00	1.39
3	1999	16.50	14.22	11.78	57.50	1	2	1.00	1.27
3	2000	16.77	14.99	13.60	54.64	1	2	1.00	1.28
3	2001	17.72	15.26	14.84	52.18	1	2	1.00	1.29
3	2002	19.61	14.82	14.71	50.86	1	2	1.00	1.31
3	2003	20.18	14.82	14.64	50.36	1	2	1.00	1.31
3	2004	20.21	15.55	12.22	52.02	1	2	1.00	1.31
3	2005	20.52	14.40	11.24	53.84	1	2	1.00	1.31
3	2006	20.53	13.07	10.73	55.67	1	2	1.00	1.30
3	2007	18.39	13.28	11.69	56.64	1	2	1.00	1.28
3	2008	16.61	13.08	12.52	57.79	1	2	1.00	1.26
4	1999	29.57	70.13	0.30	0.00	1	2	1.00	1.65
4	2000	33.07	66.93	0.00	0.00	1	2	1.00	1.67
4	2001	38.31	61.69	0.00	0.00	1	2	1.00	1.69
4	2002	43.61	56.39	0.00	0.00	1	2	1.00	1.72
4	2003	47.16	52.84	0.00	0.00	1	2	1.00	1.74
4	2004	46.77	53.23	0.00	0.00	1	2	1.00	1.73
4	2005	48.29	51.71	0.00	0.00	1	2	1.00	1.74
4	2006	49.87	50.13	0.00	0.00	1	2	1.00	1.75
4	2007	50.99	49.01	0.00	0.00	1	2	1.00	1.75
4	2008	49.10	50.90	0.00	0.00	1	2	1.00	1.75
5	1999	31.84	5.02	3.25	59.89	1	2	1.00	1.35
5	2000	33.00	5.21	3.80	57.99	1	2	1.00	1.37
5	2001	31.84	5.44	4.25	58.47	1	2	1.00	1.36
5	2002	30.86	3.89	3.59	61.66	1	2	1.00	1.34
5	2003	27.61	8.74	3.75	59.90	1	2	1.00	1.33
5	2004	26.28	8.95	5.50	59.27	1	2	1.00	1.32
5	2005	25.14	10.90	6.48	57.48	1	2	1.00	1.32
5	2006	24.26	10.05	6.88	58.81	1	2	1.00	1.31
5	2007	24.68	9.16	5.92	60.24	1	2	1.00	1.31
5	2008	24.34	10.23	7.58	57.85	1	2	1.00	1.31

Legend and notes for Table S2.

Density and sulfur content can predict unreported characteristics of crude oils more reliably in well-mixed crude feeds than in poorly mixed crude feeds. When multiple streams each comprise a small portion of the feed, if an oil stream of divergent quality is present, it will have less potential to change the quality of the total crude feed. Table S2 presents results from a simplified four-component mixing analysis for potential effects of anomalous oils on the crude feeds processed in each district and year. These results indicate that the District 4 crude feed is less well mixed than those of other districts.

a. Refinery crude feed component streams, shown in percent of total crude feed volume for simplicity of presentation, are from USEIA data on gross crude oil inputs to atmospheric distillation and refinery crude oil imports *(S1, S3)*, and California Energy Commission data on refinery inputs of crude produced in California *(S16)*.

b. Potentially anomalous streams <u>might</u> be dominated by oils in which unreported characteristics that affect processing occur in anomalously high amounts. The three streams with highest potential to effect the crude feed in this way are shown for each district and year. Component streams of crude feeds are ranked based on their potential for anomalous oil and their volume. Oils from the Western Canadian Sedimentary Basin (WCSB) dominate the highest-ranked stream (stream 1) for districts 2 and 4. The WCSB oil stream includes substantial heavy oil and bitumen sources, which tend to be high in nitrogen and vanadium *(S17-19)*, and some of this stream is partially pre-processed *(Table S3)*. The other streams are ranked based on their volume and the assumption that oils from a single country of origin or U.S. region may originate from similar geology and have similar anomalies. This assumption is made to assess the reliability of predictions based on density and sulfur for these crude feeds where more complete data for specific crude feeds are not available, and may overstate the potential for anomalies in the crude feeds processed by districts 1, 2, 3 and 5. The origins *(S3, S16)* and ranks of streams are as follows.

District 1 streams are ranked by volume for country of origin, with Nigeria supplying the largest volume (stream 1) in all years. Stream 2 was from Canada, Angola or Saudi Arabia, stream 3 was from Saudi Arabia, Venezuela, Angola or Norway, and 17-21 countries supplied other streams processed in District 1 annually. District 2 processed Canadian crude as its largest import (stream 1) each year, and its other streams are ranked by volume for foreign country of origin. Stream 2 was from Saudi Arabia in all years, stream 3 was from Nigeria, Venezuela or Algeria, and 12-20 countries supplied other streams refined in District 2 annually. District 3 streams are ranked by volume for foreign country of origin, and Mexico supplied the largest of these inputs (stream 1) in all years. Streams 2 and 3 were from Saudi Arabia or Venezuela, and 25-38 countries supplied other streams refined in District 3 annually.

District 4 processed Canadian crude as its largest import stream in all years, with virtually all of the balance from the U.S., and little or none of its crude feed came from any other country. The Canadian stream (stream 1) is dominated by oils from the WCSB, which have known potential for anomalies. Specific origins of the equal or larger U.S. stream are not reported, however, parts of the WCSB and other oil deposits with similar geology are located in District 4 *(S17)*. Limiting crude transport logistics in the landlocked Rocky Mountain states, which are unique to District 4 and help to explain the limited scope of its imports relative to those of other districts, might also result in reliance on locally produced U.S. feeds. This circumstantial evidence suggests, but does not confirm, the possibility that both the imported and domestic oils refined here might have similar anomalies. Because of this possibility the U.S. stream refined in District 4 is ranked second (stream 2).

District 5 processes substantial amounts of crude from California and Alaska. The California stream (stream 1) is larger than that from any single foreign country, and includes oils from the San Joaquin Valley, which tend to have high density relative to their sulfur content *(Table S9)*. The other streams are ranked by volume for foreign country of origin. Stream 2 was from Iraq or Saudi Arabia, stream 3 was from Ecuador, Iraq or Saudi Arabia, and 20-27 countries supplied other crude oil streams refined in District 5 annually.

c. An unreported characteristic that affects processing is assumed twice as abundant in the anomalous oil as predicted by the density and sulfur content of that oil. The assumed factor of two appears plausible based on the variability observed for nitrogen, vanadium and nickel in whole crude oils. For example, among all assays of crude oils by NETL after 1969 where density, sulfur, nitrogen and residua yield are reported (N = 728) *(S20)*, the highest-divergent 1% of oils had 1.85 times as much nitrogen by weight as predicted by density and sulfur (nonparametric regression by LOWESS, $R^2 = 0.71$). Real anomalies could vary from this factor, but since it is applied to all districts and years, results will scale in proportion to the factor chosen. A lower or higher factor would thus decrease or increase values for all results, but would not change the results for any differences between districts and years. The predicted and (assumed) excess abundance of the unreported characteristic are shown, for the anomalous oil, in the columns under note (c).

d. These results estimate, for each district and year, the potential for crude feeds to have anomalous high content for unreported characteristics that are not predicted by crude feed density and sulfur. They do not show that any such anomaly actually occurred. Potential effects in the total refinery crude feed assume that the anomalous oil is 100% of stream 1, 50% of stream 2, and 25% of stream 3 for each district and year. The percentages are discounted sequentially because of the decreasing likelihood of the same anomaly in multiple separate streams. The predicted factor is assigned to the balance of the streams for each district and year. Results are shown as increases from the predicted crude feed factor of 1.00 on the right of the table.

Relatively well-mixed crude feeds limit the effect of the anomaly in districts 1, 2, 3 and 5 to less than half of its assumed magnitude in the anomalous oil stream. This compares with crude sulfur concentrations four to eight times those of nitrogen and 160 to 500 times those of nickel and vanadium *(S17)*. The ranges of annual estimates for these districts overlap, or adjoin for districts 3 and 5. However, the estimates for District 4 are significantly larger (range: 1.65-1.75) than those for the other districts (combined range: 1.26-1.40). Further, although estimates for the other districts represent an extreme case, the assumption that anomalous oil is 50% of stream 2 might understate the potential effects on the District 4 crude feed, in the event that its Canadian and U.S. inputs both have the same anomaly.

This estimate is limited by the simplified four-component blending analysis and anomalous oil stream assumptions described above, and although it shows that unpredicted anomalies are possible in the District 4 crude feed, it represents an extreme and unlikely scenario for districts 1, 2, 3 and 5.

Table S3. Estimate calculation for Canadian synthetic crude oil (SCO) exports to districts and years.

NR = Not reported

	units	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
SCO yield from bitumen upgraders											
NEB Canada estimate[a]	$(\mathrm{m}^3 \bullet 10^6)$	18.8	18.3	20.0	25.2	29.0	34.3	31.0	37.7	39.5	37.9
ERCB Alberta estimate[b]	$(\mathrm{m}^3 \bullet 10^6)$	18.8	18.6	20.3	25.6	29.5	34.7	31.7	38.2	39.9	37.9
Upgrading method[a,b]											
Hydrocracking-based	$(\mathrm{m}^3 \bullet 10^6)$	3.2	3.0	3.3	3.4	9.3	11.4	12.7	11.9	12.7	11.7
Coking-based	$(\mathrm{m}^3 \bullet 10^6)$	15.6	15.6	16.9	22.1	21.9	23.3	19.0	26.3	27.1	26.2
SCO to Canadian refineries[c]											
All Canadian refining	$(\mathrm{m}^3 \bullet 10^6)$	13.3	12.5	12.9	12.7	12.1	16.0	14.8	15.6	17.2	17.0
Alberta refineries	$(\mathrm{m}^3 \bullet 10^6)$	10.1	9.9	10.4	9.6	8.6	11.8	11.8	12.3	13.8	13.0
Other refineries	$(\mathrm{m}^3 \bullet 10^6)$	3.2	2.6	2.5	3.1	3.4	4.2	3.1	3.3	3.4	3.9
SCO removals from Alberta[b]	$(\mathrm{m}^3 \bullet 10^6)$	8.8	7.4	8.9	14.2	17.4	21.1	18.9	24.1	25.0	25.0
Supply-demand balance											
Yield (NEB)-all refining	$(\mathrm{m}^3 \bullet 10^6)$	5.5	5.8	7.1	12.5	16.9	18.3	16.2	22.0	22.3	20.9
Removals-other ref.	$(\mathrm{m}^3 \bullet 10^6)$	5.6	4.8	6.4	11.1	14.0	16.9	15.8	20.8	21.6	21.1
Excess supply estimate	$(\mathrm{m}^3 \bullet 10^6)$	5.6	5.8	7.1	12.5	16.9	18.3	16.2	22.0	22.3	21.1
Total SCO exports											
Estimated by NEB[d]	$(\mathrm{m}^3 \bullet 10^6)$	6.5	NR	NR	9.4	NR	NR	17.5	NR	NR	19.5
SCO exports to U.S.											
Estimated by NEB[d]	$(\mathrm{m}^3 \bullet 10^6)$	6.5	NR	NR	9.4	NR	NR	17.4	NR	NR	19.3
% of total exports	(%)	100.0			100.0			99.3			99.2
Estimated by interpolation with recent supply/export ratio[e]	$(\mathrm{m}^3 \bullet 10^6)$	––	5.9	6.3	––	14.5	17.7	––	22.5	21.7	––
Consolidated estimate	$(\mathrm{m}^3 \bullet 10^6)$	6.5	5.9	6.3	9.4	14.5	17.7	17.4	22.5	21.7	19.3
Supply-export balance	$(\mathrm{m}^3 \bullet 10^6)$	-0.9	-0.1	0.8	3.2	2.4	0.6	-1.3	-0.5	0.7	1.8
SCO exports to U.S. refining districts estimated by NEB[d]											
PADD 1	$(\mathrm{m}^3 \bullet 10^6)$	0.37	NR	NR	0.26	NR	NR	0.77	NR	NR	0.46
PADD 2	$(\mathrm{m}^3 \bullet 10^6)$	5.36	NR	NR	6.02	NR	NR	11.89	NR	NR	13.68
PADD 3	$(\mathrm{m}^3 \bullet 10^6)$	0.00	NR	NR	0.27	NR	NR	0.07	NR	NR	0.09
PADD 4	$(\mathrm{m}^3 \bullet 10^6)$	0.77	NR	NR	2.36	NR	NR	3.25	NR	NR	2.49
PADD 5	$(\mathrm{m}^3 \bullet 10^6)$	0.00	NR	NR	0.45	NR	NR	1.44	NR	NR	2.62
SCO exports to districts estimated by interpolation with to recent U.S. SCO portions[e]											
PADD 1	$(\mathrm{m}^3 \bullet 10^6)$	––	0.28	0.24	––	0.49	0.69	––	0.84	0.66	––
PADD 2	$(\mathrm{m}^3 \bullet 10^6)$	––	4.52	4.41	––	9.53	11.86	––	15.56	15.15	––
PADD 3	$(\mathrm{m}^3 \bullet 10^6)$	––	0.06	0.12	––	0.30	0.22	––	0.10	0.10	––
PADD 4	$(\mathrm{m}^3 \bullet 10^6)$	––	0.97	1.30	––	3.35	3.70	––	3.77	3.21	––
PADD 5	$(\mathrm{m}^3 \bullet 10^6)$	––	0.10	0.20	––	0.87	1.26	––	2.26	2.55	––
U.S. exports–PADDs balance	$(\mathrm{m}^3 \bullet 10^6)$	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Legend and notes for Table S3.

Table S3 shows data, reported exports, and calculated estimates for synthetic crude oil (SCO) volume exported from Canada and processed in each district and year. Reported SCO exports are estimates, and these are reported as annual volumes at three-year intervals. Values for the years 2000, 2001, 2003, 2004, 2006 and 2007 are estimated by interpolation based on reported data for the two proximate years. For example, reported data for 1999 and 2002 are used to estimate exported SCO processed in 2000. These estimates thus assume there was no unknown factor that changed the relationship of exports to supply or refinery capacity greatly between the estimated year and the years immediately before and after that year. Results indicate differences between districts in SCO inputs, increasing SCO inputs with time for districts 2 and 4, and that, especially in the earlier years, the SCO came mainly from coking-based upgraders. However, the exact volume and refining characteristics of SCO processed in specific districts and years is uncertain. Notes cited in the table further discuss the sources, data quality, and methods for estimates below.

a. The first estimate of annual SCO yield for 1999-2008 is from the National Energy Board of Canada (NEB) *(S21)*.

b. The second estimate of SCO yield for 1999-2008, and yield by upgrading method for 2000-2008, are from the Energy Resources Conservation Board of Alberta (ERCB) *(S22)*. Yield by upgrader in 1999 is from the NEB *(S21)*. The exact volumes from coking- and hydrocracking-based upgrading are uncertain. One major upgrader that primarily uses the coking method also uses hydrocracking *(S22)*. Most (75%) of the SCO yield from this upgrader is assigned to coking and 25% is assigned to hydrocracking in the table.

c. SCO inputs to Canadian refineries are from Statistics Canada *(S23)*. The agency reports these inputs for light SCO, however, some intermediate and heavy crude streams from the Western Canadian Sedimentary Basin (WCSB) are delivered as blends that may contain SCO. The SCO in such blends may not be reported, for some exports or refinery inputs.

d. SCO exports, including exports the U.S. and to each U.S. district, are estimated by the NEB for 1999 *(S24)*, 2002 *(S25)*, 2005 *(S26)*, and 2008 *(S27)*. The U.S. receives nearly all these exports, however, estimated exports do not balance exactly with the excess supply of SCO estimated to be available after Canadian usage of these oils. NEB export estimates appear to exceed available supply by 0.9 and 1.3 million m^3 in 1999 and 2005, while supply appears to exceed NEB export estimates by 3.2 and 1.8 million m^3 in 2002 and 2008, respectively. This is shown in the “supply-export balance” line of the table. These differences are small for some estimation purposes, but they approach or exceed the total exports estimated for some districts and years. Refining characteristics of the SCO exports are not reported.

e. Although reported only at three-year intervals, exports increase steadily with supply, and their apportionment among the districts changes little over these intervals. This is explained by the need for disposition of the SCO created, and the unique logistical constraints posed by transport and refining of SCO from the WCSB in each district. These constraints allow a rough estimate of the relative SCO volumes exported and refined in the intervening years.

   First, total U.S. exports are estimated for years when they are not reported. The excess supply estimate for each such year is multiplied by the weighted average fraction of supply exported in the two nearest reported years. This weighted average is calculated using a 2:1 ratio to give twice as much weight to the proximate year (e.g., 1999 for the 2000 estimate) and half as much weight to the year more distant in time (2002 in this example). The supply-export balance line of the table shows that these interpolated estimates generally compare more closely with excess supply than do the reported estimates.

SCO exports to districts are then estimated by apportioning the estimated total U.S. exports for the year to be estimated based on the weighted average of each district's share of total SCO exports in the two nearest reported years. This weighted average is calculated using a 2:1 ratio to give twice as much weight to the proximate year (e.g., 1999 for the 2000 estimate) and half as much weight to the year more distant in time (2002 in this example). The bottom line of the table shows that these SCO estimates for districts balance with total estimated SCO exports to the U.S. for each year.

These estimates should be interpreted with caution as discussed above. Nevertheless, they provide evidence that SCO comprised an appreciable portion of crude refined during some years in District 2, and especially District 4, which refines much less oil in total than other districts *(Table S1).* The estimates suggest that SCO accounts for more than 10% of District 4 crude feeds and up to 8% of District 2 feeds, in some years. Reported and estimated Canadian SCO accounted for less than 2% of the crude feeds processed in districts 1, 3 and 5 during 1999-2008.

Table S 4. Evidence for effects of synthetic oil (SCO) on refinery processing during 1999-2008 in District 4.

		Refinery observations for selected parameters[a]					SCO % vol. of refinery crude feed[b]	Predictions based on non-SCO feeds[c]				Energy for excess H_2 production/m^3 crude feed[d]	
		Crude feed density	H^2 production capacity	Conversion capacity	Crude stream hydrotreating capacity	Refinery energy intensity (*EI*)		H_2 predicted by crude fd. density		csHydrotreating pred. by conv. cap.			
PADD	Year	(kg/m^3)	(m^3/m^3)	(m^3/m^3)	(m^3/m^3)	(GJ/m^3)	(%)	Predicted (m^3/m^3)	Excess (m^3/m^3)	Predicted (m^3/m^3)	Excess (m^3/m^3)	(GJ/m^3)	(% *EI*)
1	1999	858.20	13.25	0.516	0.054	3.451	0.41	19.60	––	0.122	––	––	––
1	2000	860.18	15.66	0.525	0.054	3.430	0.31	24.22	––	0.130	––	––	––
1	2001	866.34	12.71	0.481	0.029	3.518	0.28	38.66	––	0.094	––	––	––
1	2002	865.71	11.11	0.474	0.084	3.426	0.30	37.16	––	0.087	––	––	––
1	2003	863.44	16.49	0.474	0.059	3.364	0.53	31.83	––	0.087	––	––	––
1	2004	865.44	16.52	0.475	0.059	3.416	0.76	36.54	––	0.088	––	––	––
1	2005	863.38	16.59	0.476	0.058	3.404	0.83	31.70	––	0.089	––	––	––
1	2006	864.12	18.83	0.476	0.028	3.440	0.98	33.44	––	0.090	––	––	––
1	2007	864.33	14.46	0.476	0.028	3.499	0.77	33.93	––	0.090	––	––	––
1	2008	863.65	14.46	0.476	0.028	3.551	0.57	32.32	––	0.090	––	––	––
2	1999	858.25	21.23	0.486	0.125	3.368	2.74	19.73	1.50	0.097	0.028	0.022	0.66
2	2000	860.03	21.17	0.488	0.107	3.361	2.28	23.85	––	0.099	0.008	––	––
2	2001	861.33	23.18	0.485	0.096	3.396	2.30	26.91	––	0.096	––	––	––
2	2002	861.02	21.58	0.481	0.129	3.393	3.22	26.17	––	0.093	0.035	––	––
2	2003	862.80	20.02	0.477	0.132	3.298	5.09	30.35	––	0.090	0.043	––	––
2	2004	865.65	20.25	0.473	0.148	3.376	6.19	37.04	––	0.087	0.061	––	––
2	2005	865.65	24.07	0.484	0.148	3.496	6.18	37.04	––	0.096	0.052	––	––
2	2006	865.44	37.33	0.488	0.140	3.738	8.10	36.54	0.79	0.099	0.042	0.012	0.31
2	2007	864.07	36.89	0.479	0.137	3.800	8.06	33.31	3.58	0.092	0.045	0.053	1.39
2	2008	862.59	37.12	0.487	0.146	3.858	7.27	29.85	7.26	0.098	0.047	0.107	2.78
3	1999	869.00	32.51	0.566	0.151	4.546	0.00	44.95	––	0.165	––	––	––
3	2000	870.29	33.03	0.579	0.155	4.563	0.01	47.99	––	0.175	––	––	––
3	2001	874.43	34.50	0.600	0.129	4.348	0.03	57.86	––	0.193	––	––	––
3	2002	876.70	34.95	0.611	0.148	4.434	0.07	63.32	––	0.203	––	––	––
3	2003	874.48	34.66	0.604	0.168	4.381	0.07	57.99	––	0.196	––	––	––
3	2004	877.79	37.31	0.610	0.174	4.204	0.05	65.94	––	0.201	––	––	––
3	2005	878.01	35.69	0.588	0.168	4.205	0.02	66.46	––	0.183	––	––	––
3	2006	875.67	33.33	0.587	0.167	4.367	0.02	60.85	––	0.182	––	––	––
3	2007	876.98	32.83	0.594	0.184	4.226	0.02	63.97	––	0.188	––	––	––
3	2008	878.66	33.64	0.600	0.171	4.361	0.02	68.04	––	0.193	––	––	––
4	1999	854.47	28.31	0.415	0.112	3.843	2.64	10.96	17.34	0.040	0.073	0.256	6.66
4	2000	859.35	30.44	0.426	0.092	3.698	3.25	22.27	8.17	0.049	0.043	0.121	3.26
4	2001	859.19	29.92	0.421	0.050	3.846	4.43	21.91	8.01	0.045	0.005	0.118	3.07
4	2002	860.23	29.09	0.404	0.087	3.726	7.73	24.34	4.75	0.031	0.056	0.070	1.88
4	2003	861.23	27.94	0.408	0.087	3.833	10.86	26.66	1.28	0.034	0.053	0.019	0.49
4	2004	862.59	28.02	0.419	0.090	3.644	11.44	29.85	––	0.043	0.047	––	––
4	2005	862.91	41.87	0.407	0.093	3.830	9.98	30.59	11.28	0.034	0.060	0.167	4.35
4	2006	860.50	38.16	0.408	0.109	3.955	11.67	24.95	13.21	0.034	0.075	0.195	4.93
4	2007	862.38	49.76	0.415	0.109	4.159	10.13	29.36	20.39	0.040	0.069	0.301	7.24
4	2008	863.12	59.86	0.409	0.136	4.475	7.94	31.09	28.78	0.035	0.101	0.425	9.49
5	1999	894.61	69.93	0.613	0.195	4.908	0.00	107.06	––	0.204	––	––	––
5	2000	895.85	83.53	0.613	0.167	5.189	0.06	110.15	––	0.204	––	––	––
5	2001	893.76	82.53	0.619	0.174	5.039	0.13	104.95	––	0.209	––	––	––
5	2002	889.99	85.44	0.636	0.196	4.881	0.28	95.65	––	0.224	––	––	––
5	2003	889.10	83.17	0.620	0.165	4.885	0.52	93.45	––	0.210	––	––	––
5	2004	888.87	83.17	0.627	0.167	4.861	0.76	92.90	––	0.216	––	––	––
5	2005	888.99	83.44	0.626	0.166	4.774	0.86	93.18	––	0.216	––	––	––
5	2006	887.65	88.20	0.641	0.160	4.862	1.35	89.89	––	0.228	––	––	––
5	2007	885.54	89.90	0.656	0.167	5.091	1.58	84.73	5.17	0.242	––	0.076	1.50
5	2008	890.16	89.68	0.645	0.163	4.939	1.60	96.07	––	0.232	––	––	––

Legend and notes for Table S4.

Table S4 presents results from analysis of synthetic crude oil (SCO) effects on refining. Canadian export estimates *(Table S3)* suggest that during 1999-2008 SCO from Western Canada was 2-8% and 2-12% of crude feeds in districts 2 and 4, respectively. This SCO stream yields more and lower quality gas oil as compared with typical whole crude oils, and can require more hydroprocessing in refineries *(S24, S25).* Crude density correlates with hydrogen demand for crude oils generally but does not correlate well for some SCO *(S14).* Reported hydrogen capacity is compared with that predicted by crude feed density, and reported crude stream hydrotreating capacity is compared with that predicted by conversion capacity, among districts and years. Crude stream hydrotreating processes gas oil, residua and catalytic cracking feeds *(Table S1).* These comparisons provide information about the relationship of hydrogen production to hydrogen use in processing gas oil, including gas oil from refinery SCO inputs. Hydrogen production in excess of that predicted by crude feed density is then compared with total refinery processing requirements on an energy basis.

Results suggest that SCO affects hydroprocessing and hydrogen production in refineries and may have increased refinery energy intensity significantly during some years in District 4. Hydrogen excesses are found only when SCO was present in crude feeds, and are found during four years in District 2 and nine years in District 4. Hydrotreating excesses are found only when estimated SCO inputs exceeded 2% of crude feeds and occurred during nine years in District 2 and ten years in District 4. The magnitude of hydrogen excesses generally increased with that of hydrotreating excesses and both were larger in District 4 than in District 2. Energy use for excess hydrogen production was minimal in District 2, but in District 4 it exceeded 5% of total refinery energy consumed during three years, and exceeded 9% of total refinery energy in 2008. The magnitude of hydrogen excesses is not well correlated with the estimated percentage of SCO in crude feeds, especially in District 4. The extent to which this poor correlation reflects unreported changes in the quality of SCO inputs, unreported changes in the quality of the balance of the poorly-mixed District 4 crude feed *(Table S2)*, or errors in SCO volume estimates *(Table S3)*, could not be determined with available data.

a. Refinery observations shown on the left of the table are based on the data given in Table S1. Capacities/m^3 atmospheric distillation capacity are shown.

b. The percentage of total refinery crude feed volume comprised of SCO is estimated based on estimated SCO exports from Table S3 and reported total crude inputs from Table S1. The SCO export estimates are uncertain, as detailed in Table S3.

c. Predictions shown are from PLS regression on all data for districts where estimated SCO inputs never exceeded 2% of total crude feeds during 1999-2008 (districts 1, 3 and 5). R-squared values are 0.88 for hydrogen production capacity predicted by crude feed density, and 0.85 for crude stream hydrotreating capacity predicted by conversion capacity. These predictions are “blind” to the presence of SCO in that it was not included as a variable in either of these two PLS models. Predictions and excesses shown are based on the upper 95% confidence for observations. Observed values exceed the lower 95% confidence (not shown) for all comparisons.

d. Energy consumed for the excess in hydrogen production capacity, which is shown as cubic meters H_2/m^3 atmospheric distillation capacity in this table, is calculated using the energy (16.4 MJ/m^3 H_2) and capacity utilization (90%) factors from Table S1.

Table S5. Efficiency factors for processing refinery products.

Product		Efficiency factor (%)	Average specific gravity
Light liquids			
	Gasoline	86.4	0.737
	Diesel	91.0	0.845
	Kerosine	92.2	0.814
	Naphtha	92.7	0.756
Other products			
	Lube stocks	80.5	0.889
	Waxes	80.5	0.799
	Asphalt	84.9	1.038
	Coke	86.3	0.967
	Fuel gas	90.0	0.844
	Heavy fuel oil	91.0	0.946
	LPG	92.7	0.539
	Residual oil	94.1	0.946

Legend and notes for Table S5.

Product-specific processing energy efficiency factors for a current typical U.S. refinery (mass-based) from reference *S11,* and average specific gravities of North American products from reference *S28.* These values were used with yield data from Table S1 to estimate energy use for products processing ("Eproducts"). The Eproducts estimates for refining districts and years are used, with *S, d,* capacity utilized, and products ratio observations from data in Table S1, in the Eproducts v. *OQ* comparison reported in Table 1 of the main text.

Table S6. Estimate calculation, oil quality and processing *EI* including bitumen upgrading.

		Refinery observations[a]						Synthetic crude oil input estimate[b]		Coking : hydrocracking[b]
PADD	Year	Crude input $(m^3/d \cdot 10^4)$	Density (kg/m^3)	*S* (kg/m^3)	*EI* (GJ/m^3)	Cap. utilized (%)	Prod. ratio (ratio)	$(m^3/d \cdot 10^4)$	(%)	(ratio)
1	1999	24.436	858.20	8.24	3.451	90.9	3.668	0.101	0.41	4.8
1	2000	24.754	860.18	8.00	3.430	91.7	3.489	0.077	0.31	5.2
1	2001	23.546	866.34	7.71	3.518	87.2	3.479	0.065	0.28	5.2
1	2002	24.246	865.71	7.45	3.426	88.9	3.605	0.073	0.30	6.5
1	2003	25.184	863.44	7.43	3.364	92.7	3.321	0.134	0.53	2.4
1	2004	24.961	865.44	7.79	3.416	90.4	3.398	0.190	0.76	2.0
1	2005	25.422	863.38	7.17	3.404	93.1	3.756	0.212	0.83	1.5
1	2006	23.626	864.12	7.17	3.440	86.7	3.522	0.231	0.98	2.2
1	2007	23.419	864.33	7.26	3.499	85.6	3.443	0.181	0.77	2.1
1	2008	22.115	863.65	7.08	3.551	80.8	3.400	0.125	0.57	2.2
2	1999	53.626	858.25	10.64	3.368	93.3	4.077	1.469	2.74	4.8
2	2000	54.215	860.03	11.35	3.361	94.2	4.132	1.238	2.28	5.2
2	2001	52.609	861.33	11.37	3.396	93.9	4.313	1.210	2.30	5.2
2	2002	51.162	861.02	11.28	3.393	90.0	4.345	1.648	3.22	6.5
2	2003	51.258	862.80	11.65	3.298	91.6	4.281	2.611	5.09	2.4
2	2004	52.482	865.65	11.86	3.376	93.6	4.167	3.250	6.19	2.0
2	2005	52.688	865.65	11.95	3.496	92.9	4.207	3.258	6.18	1.5
2	2006	52.609	865.44	11.60	3.738	92.4	3.907	4.264	8.10	2.2
2	2007	51.480	864.07	11.84	3.800	90.1	4.161	4.152	8.06	2.1
2	2008	51.575	862.59	11.73	3.858	88.4	4.333	3.747	7.27	2.2
3	1999	111.689	869.00	12.86	4.546	94.7	3.120	0.000	0.00	4.8
3	2000	113.024	870.29	12.97	4.563	93.9	3.120	0.015	0.01	5.2
3	2001	115.600	874.43	14.34	4.348	94.8	3.128	0.033	0.03	5.2
3	2002	112.786	876.70	14.47	4.434	91.5	3.251	0.073	0.07	6.5
3	2003	116.013	874.48	14.43	4.381	93.6	3.160	0.081	0.07	2.4
3	2004	119.145	877.79	14.40	4.204	94.1	3.228	0.060	0.05	2.0
3	2005	114.534	878.01	14.40	4.205	88.3	3.316	0.020	0.02	1.5
3	2006	117.253	875.67	14.36	4.367	88.7	3.176	0.027	0.02	2.2
3	2007	117.682	876.98	14.47	4.226	88.7	3.205	0.027	0.02	2.1
3	2008	111.879	878.66	14.94	4.361	83.6	3.229	0.026	0.02	2.2
5	1999	41.973	894.61	11.09	4.908	87.1	2.952	0.001	0.00	4.8
5	2000	43.086	895.85	10.84	5.189	87.5	3.160	0.027	0.06	5.2
5	2001	44.262	893.76	10.99	5.039	89.1	3.231	0.056	0.13	5.2
5	2002	44.787	889.99	10.86	4.881	90.0	3.460	0.124	0.28	6.5
5	2003	45.661	889.10	10.94	4.885	91.3	3.487	0.238	0.52	2.4
5	2004	45.486	888.87	11.20	4.861	90.4	3.551	0.345	0.76	2.0
5	2005	46.090	888.99	11.38	4.774	91.7	3.700	0.394	0.86	1.5
5	2006	45.693	887.65	10.92	4.862	90.5	3.615	0.618	1.35	2.2
5	2007	44.373	885.54	11.07	5.091	87.6	3.551	0.700	1.58	2.1
5	2008	44.739	890.16	12.11	4.939	88.1	3.803	0.717	1.60	2.2
4	1999	8.029	854.47	11.71	3.843	95.1	3.910	0.212	2.64	4.8
4	2000	8.156	859.35	12.03	3.698	94.7	3.943	0.265	3.25	5.2
4	2001	8.077	859.19	11.08	3.846	90.7	3.986	0.357	4.43	5.2
4	2002	8.363	860.23	12.04	3.726	91.6	4.078	0.647	7.73	6.5
4	2003	8.442	861.23	12.49	3.833	91.9	3.962	0.917	10.86	2.4
4	2004	8.856	862.59	11.65	3.644	95.7	3.981	1.013	11.44	2.0
4	2005	8.935	862.91	11.22	3.830	95.5	3.887	0.892	9.98	1.5
4	2006	8.856	860.50	11.36	3.955	93.5	3.962	1.033	11.67	2.2
4	2007	8.681	862.38	11.73	4.159	91.3	3.900	0.879	10.13	2.1
4	2008	8.585	863.12	12.17	4.475	89.4	4.291	0.682	7.94	2.2

Table S6. Estimate calculation, oil quality and processing *EI* including bitumen upgrading.
Continued

		Bitumen upgrading estimate[c]			Upgrading and refining estimate				Estimate compared to *OQ* prediction[k]
PADD	Year	Density_{add}[d] (kg/m^3)	S_{add}[e] (kg/m^3)	EI_{add}[f] (GJ/m^3)	Density_{adj}[g] (kg/m^3)	S_{adj}[h] (kg/m^3)	EI_{adj}[i] (GJ/m^3)	EI_{tp}[j] (GJ/m^3)	(±% 95% Conf.)
1	1999	0.45	0.17	0.022	858.65	8.41	3.473	3.271	––
1	2000	0.34	0.13	0.017	860.52	8.13	3.447	3.372	––
1	2001	0.30	0.11	0.015	866.65	7.82	3.533	3.579	––
1	2002	0.33	0.12	0.016	866.04	7.57	3.442	3.533	––
1	2003	0.57	0.22	0.030	864.01	7.65	3.394	3.531	––
1	2004	0.81	0.32	0.043	866.25	8.11	3.459	3.623	––
1	2005	0.87	0.35	0.048	864.26	7.52	3.452	3.470	––
1	2006	1.04	0.41	0.055	865.17	7.58	3.495	3.488	––
1	2007	0.82	0.32	0.044	865.16	7.58	3.543	3.489	––
1	2008	0.60	0.24	0.032	864.25	7.32	3.583	3.393	––
2	1999	3.00	1.12	0.148	861.26	11.76	3.516	3.546	––
2	2000	2.51	0.93	0.123	862.53	12.28	3.484	3.634	––
2	2001	2.52	0.94	0.124	863.86	12.31	3.520	3.662	––
2	2002	3.56	1.30	0.172	864.58	12.58	3.565	3.667	––
2	2003	5.45	2.12	0.285	868.25	13.77	3.583	3.925	––
2	2004	6.58	2.59	0.349	872.24	14.45	3.725	4.179	-2%
2	2005	6.48	2.62	0.355	872.14	14.57	3.852	4.168	––
2	2006	8.65	3.39	0.455	874.09	14.98	4.193	4.321	––
2	2007	8.59	3.37	0.454	872.66	15.21	4.254	4.210	––
2	2008	7.75	3.03	0.408	870.35	14.76	4.266	4.038	––
3	1999	0.00	0.00	0.000	869.00	12.86	4.546	4.117	2%
3	2000	0.02	0.01	0.001	870.30	12.97	4.563	4.173	1%
3	2001	0.03	0.01	0.002	874.46	14.35	4.350	4.446	––
3	2002	0.07	0.03	0.004	876.78	14.49	4.437	4.504	––
3	2003	0.07	0.03	0.004	874.56	14.46	4.385	4.440	––
3	2004	0.05	0.02	0.003	877.84	14.42	4.207	4.575	––
3	2005	0.02	0.01	0.001	878.03	14.41	4.206	4.512	––
3	2006	0.02	0.01	0.001	875.70	14.37	4.369	4.434	––
3	2007	0.02	0.01	0.001	877.00	14.48	4.227	4.493	––
3	2008	0.02	0.01	0.001	878.69	14.95	4.362	4.541	––
5	1999	0.00	0.00	0.000	894.61	11.09	4.909	5.082	––
5	2000	0.07	0.03	0.003	895.92	10.87	5.192	5.097	––
5	2001	0.14	0.05	0.007	893.90	11.04	5.046	5.023	––
5	2002	0.31	0.11	0.015	890.30	10.97	4.896	4.834	––
5	2003	0.56	0.22	0.029	889.65	11.15	4.914	4.825	––
5	2004	0.81	0.32	0.043	889.68	11.52	4.903	4.830	––
5	2005	0.90	0.36	0.049	889.88	11.74	4.824	4.841	––
5	2006	1.44	0.57	0.076	889.09	11.48	4.938	4.793	––
5	2007	1.68	0.66	0.089	887.22	11.73	5.180	4.707	2%
5	2008	1.71	0.67	0.090	891.87	12.78	5.029	4.939	––
4	1999	2.89	1.08	0.143	857.36	12.78	3.986	3.482	4%
4	2000	3.57	1.32	0.175	862.91	13.35	3.873	3.750	––
4	2001	4.86	1.80	0.239	864.05	12.88	4.085	3.726	––
4	2002	8.54	3.13	0.414	868.78	15.17	4.139	4.065	––
4	2003	11.62	4.53	0.608	872.85	17.01	4.441	4.377	––
4	2004	12.16	4.79	0.645	874.76	16.44	4.289	4.459	––
4	2005	10.46	4.23	0.574	873.37	15.45	4.404	4.352	––
4	2006	12.45	4.87	0.655	872.94	16.23	4.610	4.349	––
4	2007	10.79	4.24	0.570	873.17	15.96	4.729	4.331	1%
4	2008	8.47	3.31	0.446	871.59	15.48	4.921	4.152	9%

Legend and notes for Table S6.

Table S6 presents an estimate of oil quality and processing energy for total oil processing, including refining and pre-processing for that portion of refinery crude feeds comprised of synthetic crude oil (SCO), for each district and year. Coking- and hydrocracking-based bitumen upgrading uses energy to yield SCO of lower density and sulfur content than the bitumen. SCO imported from Western Canada accounts for an estimated 2-8% of total District 2 crude feeds and 2-12% of total District 4 feeds during 1999-2008. Refinery crude feeds and energy consumption do not reflect the original bitumen quality for this SCO or the energy consumed in its upgrading. The estimate shown in this table relates initial oil quality to process energy for total processing. The energy consumed and density and sulfur lost in upgrading is estimated based on process modeling data and added “back” to the refinery crude feed and energy consumption observed. The estimated total process energy is then compared to that predicted by the initial oil quality. Results suggest that in general, total process energy increases with worsening initial oil quality consistent with the prediction based on observed refinery data. The exception involves two results for District 4. This is discussed in note (k).

a. Refinery feed volume, density, sulfur content (*S*), capacity utilization, and products ratio (calculated as described in the main paper) are from data in Table S1.

b. Synthetic crude oil (SCO) inputs and sources by upgrader type are from the estimates detailed in Table S3. The volume, percentage of total refinery crude feed volume, and ratio of coking- to hydrocracking-based upgrading for the SCO are shown.

c. SCO was produced from bitumen in Western Canada by coking-based and hydrocracking-based upgrading *(S22)*. Both upgrading schemes typically also use atmospheric and vacuum distillation and significant hydrotreating, sulfur recovery and hydrogen production. Material and energy inputs and outputs were estimated using process modeling of typical coking-based and hydrocracking-based upgraders yielding SCO from Athabasca bitumen by Keesom et al. *(S14).* Modeled parameters included, among others, bitumen feed density (1.011 t/m^3) and sulfur content (48.64 kg/m^3), SCO yield (22,259 m^3/d), and SCO density and sulfur content for the coking-based (881.07 kg/m^3 *d,* 3.23 kg/m^3 *S*) and hydrocracking-based (921.82 kg/m^3 *d,* 3.23 kg/m^3 *S*) schemes. Carbon rejection, hydrogen addition and utility energy inputs estimated by process modeling on these parameters were 4,773 GJ/h for the coking-based scheme and 6,155 GJ/h for the hydrocracking-based scheme *(S14).* This indicates energy inputs of approximately 0.04 GJ per kg density (including sulfur) lost from the feed in the SCO from the coking-based scheme, and 0.07 GJ/kg for that from the hydrocracking scheme. Energy inputs were not allocated to sulfur removal separately from density reduction in the reported results.

Bitumen feed to the coking- and hydrocracking-based schemes was modeled at 1.15 times and 0.97 times the SCO volume yield, respectively *(S14).* Thus, on a product volume basis, estimated energy use was approximately 5.15 and 6.64 GJ per m^3 SCO produced for the coking- and hydrocracking-based upgraders, respectively. SCO from the coking- and hydrocracking-based schemes was 130.22 and 89.47 kg/m^3 lighter than the bitumen feed, respectively, and both schemes produced SCO with 45.41 kg/m^3 less sulfur than the bitumen feed. These estimates are applied to the shares of SCO from coking- and hydrocracking-based upgrading each year to estimate initial oil quality and total process energy. Notes d through f detail the calculations.

d. Density lost in upgrading the bitumen ($\text{Density}_{\text{add}}$) is added to the total refinery crude feed density to account for the bitumen input processed upstream to produce the SCO. $\text{Density}_{\text{add}}$ is calculated as:

$\text{Density}_{\text{add}} = \text{SCOvol} \bullet (\text{DR} \div \text{VC})$

Where

SCOvol is the percentage of SCO in the total refinery crude feed; DR is the density reduction from bitumen from note (c) in kg/m^3; VC is the volume change from bitumen to SCO from note (c); and the result is in kg/m^3 refinery crude feed.

e. Sulfur lost in upgrading the bitumen (S_{add}) is added to the total refinery crude feed sulfur to account for the bitumen input processed upstream to produce the SCO. S_{add} is calculated as:

$S_{\text{add}} = \text{SCOvol} \bullet (45.41 \div \text{VC})$

Where

SCOvol is the percentage of SCO in the total refinery crude feed; 45.41 is the sulfur content reduction from bitumen from note (c) in kg/m^3; VC is the volume change from bitumen to SCO from note (c); and the result is in kg/m^3 refinery crude feed.

f. Energy lost in upgrading the bitumen (EI_{add}) is added to the refinery energy intensity calculated from the data in Table S1 (EI) to estimate the total energy intensity of processing the oil feed. EI_{add} is calculated as:

$EI_{\text{add}} = \text{SCOvol} \bullet \text{EC}$

Where

SCOvol is the percentage of SCO in the total refinery crude feed; EC is the energy consumed by upgrading in GJ/m^3 SCO from note (c); and the result is expressed as GJ/m^3 refinery crude feed.

g. Density$_{adj}$ is the sum of crude feed density and Density$_{add}$ and is an estimate of initial crude feed quality accounting for the bitumen feed upgraded to produce SCO refined.

h. S_{adj} is the sum of S and S_{add} and is an estimate of initial crude feed quality accounting for the quality of the bitumen feed upgraded to produce SCO processed in a refinery.

i. EI_{adj} is the sum of EI and EI_{add} and is an estimate of the total energy intensity of processing including upgrading and refining.

j. EI_{tp} is the total *predicted* energy intensity of upgrading and processing and is an estimate of the total energy intensity predicted by the relationship of EI to crude feed density and sulfur based on the refinery observations. EI_{tp} is the result from inputting S_{adj}, Density$_{adj}$, product ratio and capacity utilized to the prediction mode of the PLS model, which is run on the observations from districts 1, 2, 3 and 5. EI_{tp} is compared with EI_{adj} in the final column of the table (note k) and in Figure 2.

k. The final column of the table compares estimated total processing energy (EI_{adj}) with total processing energy predicted by initial oil quality (EI_{tp}). Dashed lines (--) show that the result for estimated energy falls within the 95% confidence of prediction for observations. Negative values (e.g., -1%) show the percentage by which any result falls below the 95% confidence of prediction. Positive values (e.g., 1%) show the percentage by which any result exceeds the 95% confidence of prediction.

Estimated EI_{adj} is within the prediction based on oil quality or within 3% of its confidence interval in 48 of 50 cases. The exceptions are excesses for the years 1999 and 2008 in District 4. These excesses can be attributed to high excess hydrogen production in District 4 during those years *(Table S4).* It is possible that those high hydrogen values were related to increased hydroprocessing needs for SCO, or for some other anomaly, in the District 4 crude feed during those years. The need for hydrogen addition to address the poor gas oil and distillate product qualities of SCO *(S24, S25)* and its variable quality *(S14, S24)* support this possibility. This possibility cannot be confirmed or excluded, because the SCO input volume is uncertain *(Table S3)*, its quality is unknown, and there is a potential for other sources of variability in the poorly-mixed District 4 crude feed *(Table S2)*.

Table S7. Contribution of CO_2 to CO_2e emitted by oil refineries.

	Units	CO_2	CH_4	N_2O
Refinery emissions mass				
Scope				
U.S. (NETL)	Mt/y	257.90	0.1656	0.0040
U.S. (EPA)	Mt/y	228.53	0.0873	0.0007
California	Mt/y	35.54	0.0015	0.0001
Global warming potential				
20-yr. horizon	Factor	1	62	275
100-yr. horizon	Factor	1	23	296
500-yr. horizon	Factor	1	7	156
20-yr. horizon CO_2e				
U.S. (NETL)	Mt/y	257.90	10.27	1.11
U.S. (EPA)	Mt/y	228.53	5.41	0.19
California	Mt/y	35.54	0.09	0.03
100-yr. horizon CO_2e				
U.S. (NETL)	Mt/y	257.90	3.81	1.19
U.S. (EPA)	Mt/y	228.53	2.01	0.21
California	Mt/y	35.54	0.03	0.03
500-yr. horizon CO_2e				
U.S. (NETL)	Mt/y	257.90	1.16	0.63
U.S. (EPA)	Mt/y	228.53	0.61	0.11
California	Mt/y	35.54	0.01	0.02
Range of percent total CO_2e				
20-yr. horizon	Percent	95.78-99.66	0.26-3.81	0.08-0.41
100-yr. horizon	Percent	98.10-99.82	0.10-1.45	0.08-0.45
500-yr. horizon	Percent	99.31-99.93	0.03-0.45	0.04-0.24

Legend and notes for Table S7. (Mt/y, megatons per year.) U.S. refinery emission estimates are reported as mass emitted (NETL) *(S25)* and as CO_2e emitted (EPA) *(S29).* California refinery emissions are reported as mass emitted *(S30).* Global warming potential is from the Intergovernmental Panel on Climate Change *(S31).* The U.S. (EPA) emissions mass estimate is calculated from reported CO_2e *(S29)* and 100-year global warming potential *(S31).* The percent of total CO_2e from CO_2 and the small differences between estimates shown in Table S7 support the finding that CO_2 dominates refinery greenhouse gas emissions.

Table S8. PLS inputs for CO_2 emissions predicted by *OQ*, and comparison emission estimates.
(NA, not applicable; value predicted by *OQ*)

							Predicted *EI* (95% conf.)			
PADD	Year	Density (kg/m^3)	Sulfur (kg/m^3)	Cap. utlzd. (%)	Prod. ratio (ratio)	Observed *EI* (GJ/m^3)	Lower (GJ/m^3)	Central (GJ/m^3)	Upper (GJ/m^3)	Fuel mix em. intensity (kg/GJ)
1	1999	858.20	8.24	90.9	3.668	3.451	2.877	3.241	3.604	81.53
1	2000	860.18	8.00	91.7	3.489	3.430	2.987	3.349	3.711	80.34
1	2001	866.34	7.71	87.2	3.479	3.518	3.198	3.559	3.919	81.85
1	2002	865.71	7.45	88.9	3.605	3.426	3.152	3.511	3.870	81.08
1	2003	863.44	7.43	92.7	3.321	3.364	3.133	3.493	3.853	81.51
1	2004	865.44	7.79	90.4	3.398	3.416	3.209	3.568	3.927	81.46
1	2005	863.38	7.17	93.1	3.756	3.404	3.048	3.410	3.772	81.23
1	2006	864.12	7.17	86.7	3.522	3.440	3.054	3.417	3.780	80.40
1	2007	864.33	7.26	85.6	3.443	3.499	3.067	3.433	3.800	82.28
1	2008	863.65	7.08	80.8	3.400	3.551	2.972	3.352	3.733	83.26
2	1999	858.25	10.64	93.3	4.077	3.368	2.984	3.347	3.711	78.11
2	2000	860.03	11.35	94.2	4.132	3.361	3.104	3.468	3.832	77.56
2	2001	861.33	11.37	93.9	4.313	3.396	3.126	3.495	3.863	77.46
2	2002	861.02	11.28	90.0	4.345	3.393	3.068	3.432	3.796	77.90
2	2003	862.80	11.65	91.6	4.281	3.298	3.195	3.558	3.922	78.00
2	2004	865.65	11.86	93.6	4.167	3.376	3.369	3.733	4.098	77.25
2	2005	865.65	11.95	92.9	4.207	3.496	3.362	3.725	4.089	77.27
2	2006	865.44	11.60	92.4	3.907	3.738	3.380	3.738	4.095	75.84
2	2007	864.07	11.84	90.1	4.161	3.800	3.270	3.629	3.989	75.55
2	2008	862.59	11.73	88.4	4.333	3.858	3.154	3.515	3.875	74.97
3	1999	869.00	12.86	94.7	3.120	4.546	3.759	4.117	4.476	71.61
3	2000	870.29	12.97	93.9	3.120	4.563	3.813	4.172	4.531	71.87
3	2001	874.43	14.34	94.8	3.128	4.348	4.085	4.444	4.803	72.43
3	2002	876.70	14.47	91.5	3.251	4.434	4.140	4.499	4.859	72.71
3	2003	874.48	14.43	93.6	3.160	4.381	4.076	4.435	4.794	72.81
3	2004	877.79	14.40	94.1	3.228	4.204	4.213	4.572	4.930	73.43
3	2005	878.01	14.40	88.3	3.316	4.205	4.149	4.511	4.873	73.24
3	2006	875.67	14.36	88.7	3.176	4.367	4.067	4.432	4.798	74.15
3	2007	876.98	14.47	88.7	3.205	4.226	4.127	4.491	4.856	74.93
3	2008	878.66	14.94	83.6	3.229	4.361	4.165	4.540	4.915	74.48
5	1999	894.61	11.09	87.1	2.952	4.908	4.713	5.082	5.451	70.27
5	2000	895.85	10.84	87.5	3.160	5.189	4.725	5.092	5.460	69.09
5	2001	893.76	10.99	89.1	3.231	5.039	4.648	5.014	5.380	69.38
5	2002	889.99	10.86	90.0	3.460	4.881	4.450	4.814	5.178	69.15
5	2003	889.10	10.94	91.3	3.487	4.885	4.422	4.788	5.153	69.40
5	2004	888.87	11.20	90.4	3.551	4.861	4.410	4.775	5.140	69.89
5	2005	888.99	11.38	91.7	3.700	4.774	4.409	4.780	5.151	69.88
5	2006	887.65	10.92	90.5	3.615	4.862	4.331	4.695	5.060	69.32
5	2007	885.54	11.07	87.6	3.551	5.091	4.235	4.594	4.953	69.12
5	2008	890.16	12.11	88.1	3.803	4.939	4.456	4.824	5.191	68.39
Other inputs										
US	2002	873.89	12.32	90.7	3.534	NA	3.838	4.194	4.549	73.62
US	2005	875.08	12.43	90.6	3.597	NA	3.885	4.241	4.597	73.98
US	2006	873.78	12.32	89.7	3.458	NA	3.835	4.191	4.547	73.94
US	2007	873.89	12.50	88.5	3.485	NA	3.833	4.190	4.547	74.34
SFBA	2008	899.66	11.91	90.8	3.469	NA	4.938	5.307	5.676	68.39
Heavy oil		957.40	27.80	90.8	3.469	NA	8.228	8.795	9.363	73.77
Nat. bitumen		1 033.60	45.50	90.8	3.469	NA	12.266	13.200	14.135	73.77

Table S8. PLS inputs for CO_2 emissions predicted by *OQ*, and comparison emission estimates, *continued*.

PADD	Year	Central *EI* prediction (GJ/m^3)	Fuel mix em. intensity (kg/GJ)	Observed emissions (kg/m^3)	Predicted emissions (95% conf.) Lower (kg/m^3)	Predicted emissions (95% conf.) Central (kg/m^3)	Predicted emissions (95% conf.) Upper (kg/m^3)	Comparison (± % CI)
1	1999	3.241	81.53	281	243	265	287	––
1	2000	3.349	80.34	276	249	270	292	––
1	2001	3.559	81.85	288	257	279	301	––
1	2002	3.511	81.08	278	255	277	299	––
1	2003	3.493	81.51	274	254	276	298	––
1	2004	3.568	81.46	278	258	279	301	––
1	2005	3.410	81.23	277	251	272	294	––
1	2006	3.417	80.40	277	252	273	294	––
1	2007	3.433	82.28	288	251	273	295	––
1	2008	3.352	83.26	296	247	269	292	+1.4%
2	1999	3.347	78.11	263	249	271	292	––
2	2000	3.468	77.56	261	254	276	298	––
2	2001	3.495	77.46	263	256	277	299	––
2	2002	3.432	77.90	264	253	274	296	––
2	2003	3.558	78.00	257	259	280	301	-0.5%
2	2004	3.733	77.25	261	267	288	309	-2.2%
2	2005	3.725	77.27	270	266	288	309	––
2	2006	3.738	75.84	284	267	289	310	––
2	2007	3.629	75.55	287	262	284	306	––
2	2008	3.515	74.97	289	256	279	301	––
3	1999	4.117	71.61	326	285	307	328	––
3	2000	4.172	71.87	328	287	309	331	––
3	2001	4.444	72.43	315	300	321	342	––
3	2002	4.499	72.71	322	302	323	345	––
3	2003	4.435	72.81	319	299	320	342	––
3	2004	4.572	73.43	309	305	326	348	––
3	2005	4.511	73.24	308	302	324	345	––
3	2006	4.432	74.15	324	299	320	341	––
3	2007	4.491	74.93	317	301	322	344	––
3	2008	4.540	74.48	325	303	325	346	––
5	1999	5.082	70.27	345	328	350	372	––
5	2000	5.092	69.09	358	329	351	373	––
5	2001	5.014	69.38	350	325	347	369	––
5	2002	4.814	69.15	338	317	338	360	––
5	2003	4.788	69.40	339	315	337	359	––
5	2004	4.775	69.89	340	315	336	358	––
5	2005	4.780	69.88	334	315	337	358	––
5	2006	4.695	69.32	337	311	333	354	––
5	2007	4.594	69.12	352	307	328	350	+0.5%
5	2008	4.824	68.39	338	317	339	361	––
Other inputs								
US	2002	4.194	73.62	315	288	309	331	––
US	2005	4.241	73.98	285	290	311	333	-1.7%
US	2006	4.191	73.94	277	288	309	330	-3.9%
US	2007	4.190	74.34	280	288	309	330	-2.6%
SFBA	2008	5.307	68.39	360	338	360	383	––

Legend and notes for Table S8.

Table S8 shows inputs for emissions predicted by crude feed quality and compares the predictions with observed or estimated emissions. Observed crude feed density and sulfur, capacity utilized and products ratio were compared with observed *EI* among districts and years. Predicted *EI* values are the results from this PLS analysis, and are shown for the central prediction and the 95% confidence of prediction for observations. The central *EI* prediction and the observed fuel mix emission intensity were then compared with observed emissions among districts and years. Predicted emissions are the results from this PLS analysis, and are shown for the central prediction and the 95% confidence of prediction for observations. The observations compared among districts and years are from the data in Table S1. Other inputs shown at the bottom of the table were used in the prediction mode of these PLS models.

For U.S. refineries in 2002, 2005, 2006 and 2007, all data except estimated annual emissions are from Table S1. USEIA estimated that U.S. refineries emitted 277.6 megatons (Mt) of CO_2 in 2002 *(S32).* The National Energy Technology Laboratory estimated that U.S. refineries emitted 257.9 Mt in 2005 *(S12).* USEIA estimated that U.S. refineries emitted 250.7 Mt in 2006 and 251.3 Mt in 2007 *(S33).* U.S. refinery crude feed volumes in 2002, 2005, 2006 and 2007 totaled $241.3 \bullet 10^4$, $247.7 \bullet 10^4$, $248.0 \bullet 10^4$ and $245.6 \bullet 10^4$ m^3/day respectively *(Table S1).*

OQ inputs for San Francisco Bay Area (SFBA) refineries in 2008 were estimated as detailed in Table S9. The domestic component of SFBA crude feeds was more limited and better characterized than that of refinery crude feeds statewide, and this allowed a more reliable *OQ* estimate for SFBA refining than that which could be derived from publicly reported data for California refineries statewide. Although it has less capacity than Southern California, the SFBA has greater total crude capacity than other refining centers in District 5 *(S7).* The District 5 fuel mix during 2008 is used for the SFBA prediction to account for fuel mix differences observed among districts *(Table S1)*. SFBA inputs for capacity utilized and products ratio were the US averages for 1999-2008 from Table S1. Third party-certified estimates of emissions from SFBA refineries and adjacent plants supplying them hydrogen, as reported by the California Air Resources Board *(S34)*, total 17.18 Mt in 2008. Crude feed volume was estimated as the total crude capacity of SFBA refineries in 2008 ($13.07 \cdot 10^4$ m^3/day) reported by *Oil & Gas Journal (S7)*. This SFBA emissions estimate (360 kg/m^3) compares with estimated California emissions of 354 kg/m^3 based on estimated emissions (36.88 Mt) and crude feed volume ($28.5 \cdot 10^4$ m^3/day) for refineries statewide in 2008 *(S34, S35)*.

The California Air Resources Board *(S36, S37)* reported estimated CO_2 emissions from refining the average crude feed in California, including those from bulk vents and refinery fuels acquisition, of 13.34 g/MJ gasoline (CARBOB) and 11.19 g/MJ diesel (ULSD) for 30.10 GJ/m^3 gasoline and 33.86 GJ/m^3 diesel. The California Energy Commission *(S35)* reported 2008 California refinery crude inputs, gasoline (RBOB, CBOB) yield, and diesel (≤ 15 ppm sulfur) yield of 104.04, 51.11 and 21.61 $m^3 \cdot 10^6$ respectively (total gasoline and diesel yield was 61.05 and 23.06 $m^3 \cdot 10^6$ respectively). These reports suggest refinery emissions of 197.2 and 78.7 kg/m^3 crude refined for California-grade gasoline and diesel production, respectively.

OQ inputs for heavy oil and natural bitumen are the average densities and sulfur contents of heavy oil and natural bitumen reported by the U.S. Geologic Survey *(S17)*. Other inputs for heavy oil and natural bitumen assume the 1999-2008 U.S. averages based on the data from Table S1. The 1999-2008 fuel mix assumption may be conservative for future emissions from refining lower quality oil, which tends to create more byproduct gases and petroleum coke that could replace some of the natural gas now burned as fuel. Refinery emissions observations were not available for these oils.

The columns on the right of the table compare predicted and observed emissions. Horizontal lines (—) indicate that the result is within the 95% confidence of prediction. Emissions observed among districts and years vary consistently with those predicted by *OQ*, fall within the 95% confidence of prediction in 36 of 40 cases, and fall within 3% of the confidence of prediction in all cases. Emissions estimated by government agencies fall within the prediction in 2 of 5 cases and fall within 4% of its confidence interval in all cases. The agency estimates differ from each other by 12% to 30% while they differ from the central prediction based on *OQ* by 0.1% to 10%.

Table S9. Estimate calculation, San Francisco Bay Area crude feed *OQ* in 2008.

Crude feed vol. (m^3/d)	Foreign^a	SJV^b	ANS^c	Subtotal^d
Benicia Plant	$8.870\bullet10^3$	$5.323\bullet10^3$	$7.987\bullet10^3$	$2.218\bullet10^4$
Golden Eagle Plt.	$9.683\bullet10^3$	$7.987\bullet10^3$	$7.930\bullet10^3$	$2.560\bullet10^4$
Martinez Plt.	$4.837\bullet10^3$	$1.992\bullet10^4$	$4.592\bullet10^2$	$2.522\bullet10^4$
Richmond Plt.	$2.992\bullet10^4$	0	$8.710\bullet10^3$	$3.863\bullet10^4$
Rodeo/S. Maria Plt.	$1.611\bullet10^3$	$1.450\bullet10^4$	$2.968\bullet10^3$	$1.908\bullet10^4$
Crude feed mass (kg/d)	Foreign^a	SJV^e	ANS^f	Total
Whole crude	$4.827\bullet10^7$	$4.540\bullet10^7$	$2.392\bullet10^7$	$1.176\bullet10^8$
Sulfur in crude	$7.592\bullet10^5$	$5.901\bullet10^5$	$2.076\bullet10^5$	$1.557\bullet10^6$
		OQ	*S* (kg/m^3)	**11.91**
			d (kg/m^3)	**899.66**

Legend and notes for Table S9.

The *OQ* input for the San Francisco Bay Area refineries prediction (*S* and *d, Table S8)* is an estimate based on crude feed from foreign, Alaskan North Slope (ANS) and California oils that assumes transport logistics result in California supply from San Joaquin Valley crude delivered by pipeline (SJV) *(S16, S38).* SJV portions of refinery feeds *(S39)* are used with refinery capacities *(S7)* and foreign crude feed volumes *(S40)* to estimate SJV volume processed. ANS volume is then estimated by difference. Weighted average crude feed *OQ* is estimated using these feed volumes and foreign *(S40),* SJV *(S38, S41)* and ANS *(S42)* crude quality data. Superscript notes in Table S9 identify the usage of these data in the estimate calculation specifically:

(a) Foreign crude feed volume, density and sulfur content reported for each plant *(S40).*

(b) San Joaquin Valley pipeline crude volume based on SJV percentage of refinery feed reported *(S39)* and crude charge capacities *(S1).*

(c) Alaskan North Slope (ANS) volume estimated by difference.

(d) Refinery crude charge capacities from *Oil & Gas Journal (S7).*

(e) Based on SJV volume processed by Bay Area refineries, weighted average density (951.0 kg/m^3) from available data *(S38),* and sulfur content (12.36 kg/m^3) *(S41).*

(f) From ANS volume calculated, and density (860.18 kg/m^3) and sulfur content (7.40 kg/m^3) of ANS crude at the Richmond Plant *(S42).*

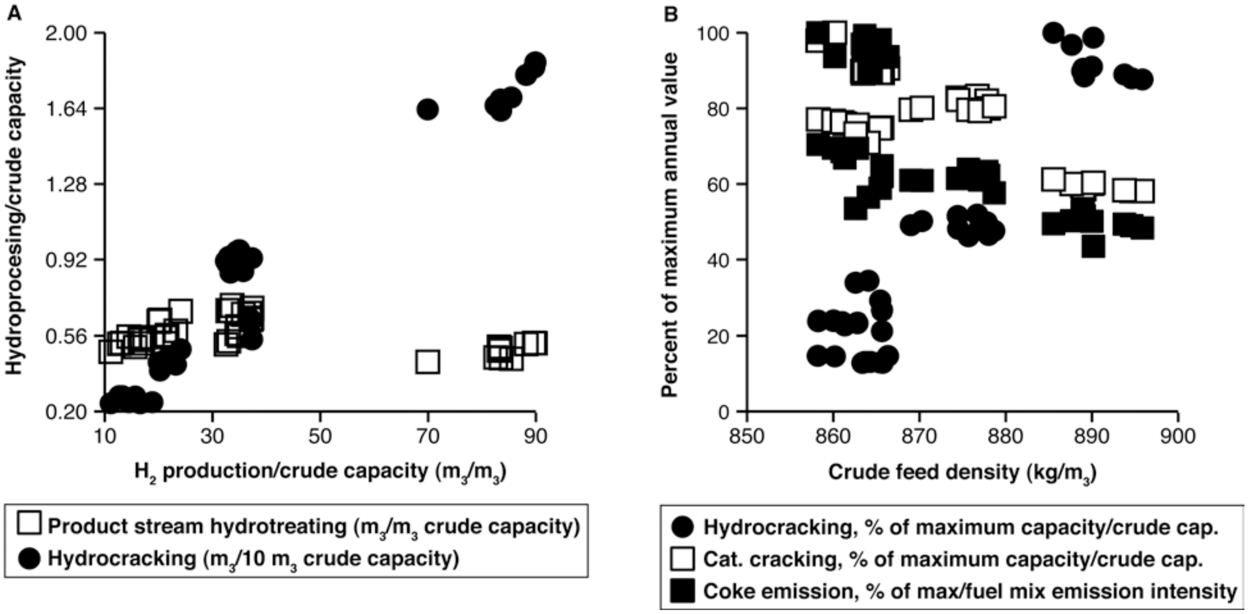

Figure S1. Some shifts among hydrogen addition and carbon rejection technologies affecting relationships between (A) hydrotreating and hydrogen production, and (B) fuel mix emission intensity and crude feed density, across refining districts 1, 2, 3 and 5, 1999-2008. All observations shown are from the data in Table S1.

A. Decreasing hydrotreating/hydrocracking ratio with increasing hydrogen production. Capacities are shown per volume atmospheric crude distillation capacity. Hydrocracking capacities are much smaller than total hydrotreating capacities and are shown at ten-times scale to reveal trends for both types of hydroprocessing. Hydrocracking uses much more hydrogen per volume oil feed than hydrotreating *(S43)*, though actual unit H_2 requirements vary by type and quality of feed, unit design, catalyst type and condition, firing rate and quench rate of process units. Hydrocracking increases steadily with hydrogen production while product hydrotreating does not. Hydrotreating increases with H_2 production at lower H_2 production but is lowest at highest H_2 production. Relative to hydrocracking capacity, hydrotreating capacity decreases steadily with increasing H_2 production, from the largest capacity relative to hydrocracking in

District 1 (H_2 capacity 13-19 m^3/m^3 crude capacity) to the smallest relative to hydrocracking in District 5 (H_2 capacity 69-90 m^3/m^3).

B. Decreasing petroleum coke contribution to total fuel mix emissions with increasing crude feed density. The portion of total fuel mix emissions accounted for by petroleum coke and the process capacities/volume crude capacity are shown as percentages of the maximum (100%) for each value. The observed increase in hydrocracking with density is consistent with the strong positive associations of hydrogen production with both hydrocracking and density *(Table 1, main text).* Coke accounts for a decreasing portion of fuel mix emissions as crude feed density and hydrocracking increase. This change for coke, which has higher emission intensity than other major refinery fuels, can explain why the fuel mix emission intensity decreases slightly with worsening oil quality *(Table S1).* Despite increasing total conversion capacity (hydrocracking, catalytic cracking, and thermal coking), catalytic cracking capacity per vol. crude capacity decreases as crude feed density and hydrocracking increase. The ratio of catalytic cracking to hydrocracking decreases across districts, following the hydrotreating pattern noted above. Decreasing catalytic cracking explains decreasing coke emissions because cracking catalyst regeneration is a major cause of coke combustion in refineries.

The shifts from hydrotreating and catalytic cracking to hydrocracking observed can explain the coincidence of slightly lower hydrotreating at high hydrogen production, and of slightly decreasing fuel mix emission intensity as crude feed density increases, for these districts and years. Refiners can choose to substitute hydrocracking for hydrotreating and catalytic cracking to some extent, but the relative importance of crude feed quality among the factors that influenced such business decisions is beyond the scope of this study.

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Regulatory Concept Paper

Petroleum Refining Emissions Tracking Rule
Bay Area Air Quality Management District
Draft: October 15, 2012

Background

Petroleum refineries convert crude oil into a wide variety of refined products, including gasoline, aviation fuel, diesel and other fuel oils, lubricating oils, and feed stocks for the petrochemical industry. Crude oil consists of a complex mixture of hydrocarbon compounds with smaller amounts of impurities including sulfur, nitrogen, oxygen and metals (e.g., iron, copper, nickel, and vanadium). Crude oil that originates from different geographical locations may vary significantly with respect to its “quality”, as is most often determined by the oils’ density (light to heavy) and sulfur content (sweet to sour).

The industry standard measure for crude oil density is API gravity, which is expressed in units of degrees, and which is inversely related to density (i.e., a lower API gravity indicates higher density; a higher API gravity indicates lower density). “Light crude” generally refers to crude oil with API gravity of 38 degrees or more; “medium crude” has API gravity between 22 and 38 degrees; and “heavy crude” has API gravity of 22 degrees or less. “Sweet crude” is commonly defined as crude oil with a sulfur content of less than 0.5%, while “sour crude” has a sulfur content of greater than 0.5%.

"Light sweet crude" is the most sought-after type of crude oil as it contains a disproportionately large amount of the hydrocarbon fractions that are used in the more valuable refined products (e.g., gasoline, fuel oils, and aviation fuel). “Heavy sour crude” is significantly less expensive than “light sweet crude” because it contains a large amount of the hydrocarbon fractions heavier than diesel, is higher in sulfur content, and is therefore more difficult and expensive to turn into the more valuable refined products.

The quality of crude oil imports in the United States has steadily declined over the last several decades both in terms of density and sulfur content. Sour crudes also tend to be more corrosive than sweet crudes, and so there has also been an increase in the corrosiveness of imported crudes over time. The trend towards lower quality crudes is largely due to the refiners’ preference for quality crudes – this has led to the depletion of those reserves and reduced the market share of the light sweet crude that remains. These trends are expected to continue; some have estimated that worldwide production of heavy sour crudes will increase by about one-third by the year 2020.

Another issue that refiners have been faced with in recent years is increasingly more stringent regulatory standards for higher quality refined products. Both the U.S. EPA and the California Air Resources Board have adopted regulations that require refineries to significantly reduce the sulfur content of gasoline and diesel fuel, and other types of “reformulated fuel” standards have also been adopted.

Refiners have therefore had to confront two opposite forces – a crude supply that is of increasingly lower quality, and mandates that require high quality reformulated fuels. In order to address these issues, refiners have responded in a variety of ways. One of the primary changes being made at virtually all refineries is to increase the amount of hydrotreating that occurs. Hydrotreating is the principle method for removing sulfur from crude oil, and it involves a chemical process in which hydrogen reacts with the sulfur to create hydrogen sulfide that can easily be removed from the oil. Other changes have included an increased reliance on processes that convert heavy oil into light products (e.g. coking). Increases in the corrosiveness of crude oil has been mitigated by the addition of compounds to neutralize the acid, while some refiners have chosen to upgrade their piping and unit materials to stainless steel. In some cases, low quality crude oil from the producing region is pre-processed to "upgrade" the oil to higher quality specifications before it is sent to the refinery (e.g., extra heavy oils, like those from the Orinoco region in Venezuela or the Alberta tar sands in Canada, are typically upgraded in a process that is both capital- and energy-intensive, but that yields a higher-quality "syncrude").

The Congressional Research Service's report for congress entitled "The U.S. Oil Refining Industry: Background in Changing Markets and Fuel Policies" (Nov. 22, 2010) summarizes the trend in crude oil quality, and the refiners responses, as follows:

> "Over the last 25 years, the API gravity of imported crude oils has been decreasing while average sulfur content has been increasing. API gravity, a measure developed by the American Petroleum Institute, expresses the "lightness" or "heaviness" of crude oils on an inverted scale. With a diminishing supply of light sweet (low sulfur) crude oil, U.S. refiners have had to invest in multi-million dollar processing-upgrades to convert lower-priced heavier crude oils to high-value products such as gasoline, diesel, and jet fuel." (Page 13)

Existing Regulatory Setting

Bay Area refineries are subject to various air quality rules that have been adopted by the Air District, CARB and U.S. EPA. These rules contain standards that are expressed in a variety of forms to ensure that emissions are effectively controlled including: (1) requiring the use of specific emission control strategies or equipment (e.g., the use of floating roof tanks for VOC emissions), (2) requiring that emissions generated by a source be controlled by at least a specified percentage (e.g., 95% control of VOC emissions from pressure relief devices), (3) requiring that emissions from a source not exceed specific concentration levels (e.g., 100 ppm by volume of VOC for equipment leaks, unless those leaks are repaired within a specific timeframe; 250 ppm by volume SO_2 in exhaust gases from sulfur recovery units; 1000 ppm by volume in exhaust gases from catalytic cracking units), (4) requiring that emissions not exceed certain quantities for a given amount of material processed or fuel used at a source (e.g., 0.033 pounds NOx per million BTU of heat input, on a refinery-wide basis, for boilers, process heaters, and steam generators), (5) requiring that emissions be controlled sufficient to not result in off property air concentrations above specified levels (e.g., 0.03 ppm by volume of H_2S in the ambient air), (6) requiring that emissions from a source not exceed specified opacity levels based on visible emissions observations (e.g., no more than 3 minutes in any hour in which emissions are as dark or darker than No. 1 on the Ringelmann chart), and (7) requiring that emissions be minimized by the use of all feasible prevention measures (e.g., flaring prohibited unless it is in accordance with an approved Flare Minimization Plan). Air quality rules generally do not expressly limit mass emissions (e.g., pounds per year of any particular regulated air pollutant) from affected equipment unless that equipment was constructed or modified after March 7, 1979 and subject to the Air District's New Source Review (NSR) rule. All Bay Area refineries have "grandfathered" emission sources that were not subject to NSR, and so none of these facilities have overall mass emission limits that apply to the entire refinery. Nonetheless, mass emissions of relevant regulated air pollutants from Bay Area refineries are closely monitored, and these mass emissions have generally been substantially reduced over the past several decades.

Air Quality Issues

There have been concerns expressed about the air quality impacts that may result from the use of lower quality crude slates at refineries. The use of lower quality crude at refineries could potentially mean increased emissions of air contaminants such as sulfur containing pollutants from sulfur recovery facilities. Emissions could also increase as a result of accidents related to the increased corrosiveness of lower quality crudes. Processing lower quality crudes also requires more intense processing and higher energy requirements, which can result in increased air emissions. In order to address these issues, it has been suggested that: (1) limits should be set on the use of heavy, high sulfur, crude oil at refineries, (2) refineries should be required to replace old boilers, heaters, and other energy inefficient equipment with new equipment that utilizes the Best Available Control Technology to reduce air pollutants, and (3) refineries should be required to use clean renewable power instead of "grid electricity" or fossil-fuel based power produced onsite.

Others contend that existing regulatory programs have resulted in significant emission reductions at refineries over the last decades even as the quality of crude oil inputs has been reduced. These regulatory programs would provide continued assurances that air emissions would not increase; or that any emission increases that might occur would not be significant in terms of health risks to the public. An increase in accidental releases due to the processing of more corrosive crudes can be prevented through the use of appropriate equipment, operating and maintenance procedures, and training requirements. Energy efficiency measures are already being implemented at refineries in response to the need to upgrade equipment to meet changing market conditions (in California, these now include market conditions resulting from the Cap-and-Trade program to reduce GHG emissions). Finally, the use of many types of renewable power (e.g., solar and wind) are impractical for refineries that must operate on a continuous basis.

Proposal for Addressing Air Quality Issues

The Air District would develop a rule that would apply to all five petroleum refineries in the Bay Area and that would track changes in the facility's air emissions. Any observed increases in air emissions at the facility above baseline levels would trigger: (1) a requirement for an analysis of the cause of the emissions increase (which may include various factors such as increases in production levels or declining crude oil quality), and (2) a requirement for an assessment of local public health impacts in the surrounding community resulting from the emissions increase. Any significant increases in emissions, as determined based on the impacts analysis, would trigger a requirement for mitigation through the use of best management practices or other appropriate measures. Information associated with rule implementation would be made available to the public, and a process would be established whereby information of a "business confidential" nature would be protected.

Information on crude oil quality could be tracked in terms of its density, sulfur content, and perhaps using the results of other available chemical or physical analyses. Air emissions are already tracked at Bay Area refineries, but the specific methods used vary to some extent from one facility to another. Since emissions at a given facility may be impacted by events such as turnarounds and accidental releases that don't occur every year, it may be appropriate that baseline and post-baseline emissions be established on a multi-year basis.

The proposed rule could incorporate elements similar to those utilized in Air District Regulation 12, Rule 12: Flares at Petroleum Refineries. Rule 12-12 requirements include: (1) flaring and associated emissions must be reported, (2) reports must be submitted as to the cause of flaring, and (3) Flare Minimization Plans (FMPs), which contain a variety of information about how flaring emissions have been, and will continue to be, minimized, must be prepared and updated on an annual basis. Information regarding flare activity and emissions are made available to the public, and FMPs are prepared and updated using a process that includes public review and comment, while providing a process to protect information that is considered business confidential. Rule 12-12 (and the related Air District Rule 12-11: Flare Monitoring at Petroleum Refineries) resulted in significant decreases in flaring activity and emissions at Bay Area refineries, and has served as a model for similar rules adopted by other agencies including U. S. EPA.

The proposed rule could also require that refineries establish more robust monitoring systems to detect emitted air pollutants along their facility boundaries and/or in nearby communities. Community-based air quality monitors could provide valuable data on public exposures to air pollutants emitted on a routine basis, and as a result of accidental releases.

Schedule

Air District staff could begin the rule development process in late 2012, with the goal of bringing a proposed Petroleum Refining Emissions Tracking Rule to the District's Board of Directors for consideration of adoption in the first half of 2014.

BAY AREA AIR QUALITY MANAGEMENT DISTRICT
RESOLUTION NO. 2014-07

A Resolution of the Board of Directors of the Bay Area Air Quality Management District

Addressing Emissions from Bay Area Petroleum Refineries

WHEREAS, the Bay Area has five major oil refineries that contribute to local, regional, and global air pollution;

WHEREAS, refinery air pollution is known to contain chemicals that are hazardous to public health including but not limited to carcinogens such as benzene and benzo(a)pyrene, acids such as sulfuric acid and hydrochloric acid, heavy metals such as lead and mercury, teratogens such as toluene, mutagens such as polycyclic aromatic hydrocarbons;

WHEREAS, refineries emit fine particulate matter ($PM_{2.5}$) along with other stationary sources, vehicles and wood burning, which has been recognized by the Bay Area Air Quality Management District ("Air District") in its report, *Understanding Particulate Matter* (November 2012), as "the pollutant that poses by far the greatest health risk to Bay Area Residents", associated with premature mortality from cardiac illness, stroke and lung cancer, increased respiratory illness and asthma, increased hospital admissions, and greater school absences and missed workdays;

WHEREAS, all Bay Area refineries are in the process of infrastructure and crude oil changes that have the potential to result in significant worsening of air quality;

WHEREAS, measures to reduce Bay Area refinery emissions of criteria air pollutants and toxic air contaminants will support the goals of the Air District's *2010 Clean Air Plan* as well as the *2015 Clean Air Plan* now in development;

WHEREAS, pursuant to the California Clean Air Act and Amendments (HSC Sections 39002 and 40910 et seq.) and the Federal Clean Air Act and Amendments (42 U.S.C. Section 7401 et seq.), the Air District has authority to regulate emissions from non-vehicular sources of air pollution, including GHGs, and has the authority to enact more protective requirements than federal or State law;

WHEREAS the Air District meets or exceeds federal and state requirements to control and monitor sources of criteria pollutants and toxic air contaminants resulting in continuing reductions of these air pollutants over time as measured by the Air District's ambient air monitoring network;

WHEREAS regional, State and federal regulations and programs have resulted in significant reductions in criteria air pollutants, air toxic emissions and risk, there are still communities with elevated exposures that warrant further action;

WHEREAS stationary source emissions in the Bay Area contribute to public exposure to air pollution, and health risk in neighboring communities, with petroleum refineries historically being among the largest stationary sources and consequently the focus of over 21 specific Air District regulations and programs;

WHEREAS Air District staff is currently preparing the 2015 Clean Air Plan and, as such, is investigating sources at petroleum refineries, their current emissions and regulatory limits and methods to further reduce overall emissions from petroleum refineries, leveraging information, methods and experience gained from the aforementioned programs and regulatory actions;

WHEREAS the Air District is in the process of developing proposed Regulation 12, Rule 15; Petroleum Refinery Emissions Tracking to track emissions, require updated Health Risk Assessments (HRAs) and monitor at fence-lines and neighboring communities, and a companion proposed regulation, Regulation 12, Rule 16, setting emissions thresholds and mitigating potential emissions increases;

NOW, THEREFORE, BE IT RESOLVED THAT Air District staff shall continue to prepare Regulation 12, Rule 15, Petroleum Refinery Emissions Tracking, to track and monitor refinery emissions, for proposed adoption by the Board of Directors not later than Spring 2015;

AND BE IT FURTHER RESOLVED THAT Air District staff shall prepare a companion Regulation 12, Rule 16, to set emissions thresholds and mitigate potential emissions increases, for proposed adoption by the Board of Directors not later than Spring 2015;

AND BE IT FURTHER RESOLVED THAT in order to continue to reduce air pollution from petroleum refineries, the Board of Directors directs Air District staff to develop a strategy based on an evaluation of approaches to further reduce emissions from petroleum refineries, including:

- the "worker-community" approach outlined in a September 26, 2014 letter;
- approach(es) proposed by industry;
- approach(es) to require each refinery to develop a refinery emissions improvement plan to implement a suite of measures to demonstrate compliance with all applicable requirements of the afore-mentioned strategy to further reduce emissions from petroleum refineries and to identify any additional feasible measures to achieve best practices with respect to minimizing emissions and to assure continuous improvement in minimizing emissions;
- other approaches deemed appropriate by Air District staff;

AND BE IT FURTHER RESOLVED THAT Air District staff shall prepare a strategy to achieve further emissions reductions from petroleum refineries which shall include as a goal a 20% reduction in refinery emissions, or as much emissions reductions as are feasible, and shall include a schedule to implement the strategy through regulations or other enforceable mechanisms as expeditiously as possible;

AND BE IT FURTHER RESOLVED THAT Air District staff shall present the evaluation of emission reduction approaches and recommend a strategy to further reduce petroleum refinery emissions to the Board of Directors no later than December 2014;

AND BE IT FURTHER RESOLVED THAT Air District staff shall re-evaluate the goal as part of the 2015 Clean Air Plan process and modify the goal as necessary.

The foregoing resolution was duly and regularly introduced, passed and adopted at a regular meeting of the Board of Directors of the Bay Area Air Quality Management District on the Motion of Director BATES, seconded by Director GIOIA, on the ____ day of October 15, 2014 by the following vote of the Board:

AYES: KIM, PEPPER, SPERING, KNISS, BATES, GIOIA, MAR, MILEY, GROOM, KALRA, WAGENKNECHT, ROSS, AVALOS, ADAMS, FUJIOKA

NOES: NONE

ABSTENTIONS: NONE

ABSENT: PIEPHO, HUDSON, ZANE, KLATT, HAGGERTY, BARRETT, CHAVEZ

Nate Miley

Nate Miley
Chairperson of the Board of Directors

ATTEST:

Eric Mar
Secretary of the Board of Directors

Attachment KR-5

Excerpts from the State Implementation Plan Adopted by BAAQMD 19 April 2017

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SPARE THE AIR· COOL THE CLIMATE

A BLUEPRINT FOR CLEAN AIR AND CLIMATE PROTECTION IN THE BAY AREA

FINAL 2017 CLEAN AIR PLAN

BAY AREA
AIR QUALITY
MANAGEMENT
DISTRICT

ADOPTED APRIL 19, 2017

BAY AREA AIR QUALITY MANAGEMENT DISTRICT

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Karen Schkolnick, Director of Strategic Incentives
(Acting)

Eric Stevenson, Director of Measurements,
Meteorology and Rules

Jaime Williams, Director of Engineering and
Information Technology

Lisa Fasano, Communications Officer

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APPENDICES

Figure 2-6. **Direct $PM_{2.5}$ Emissions by Source, Annual Average, 2015 (47 tons/day)**

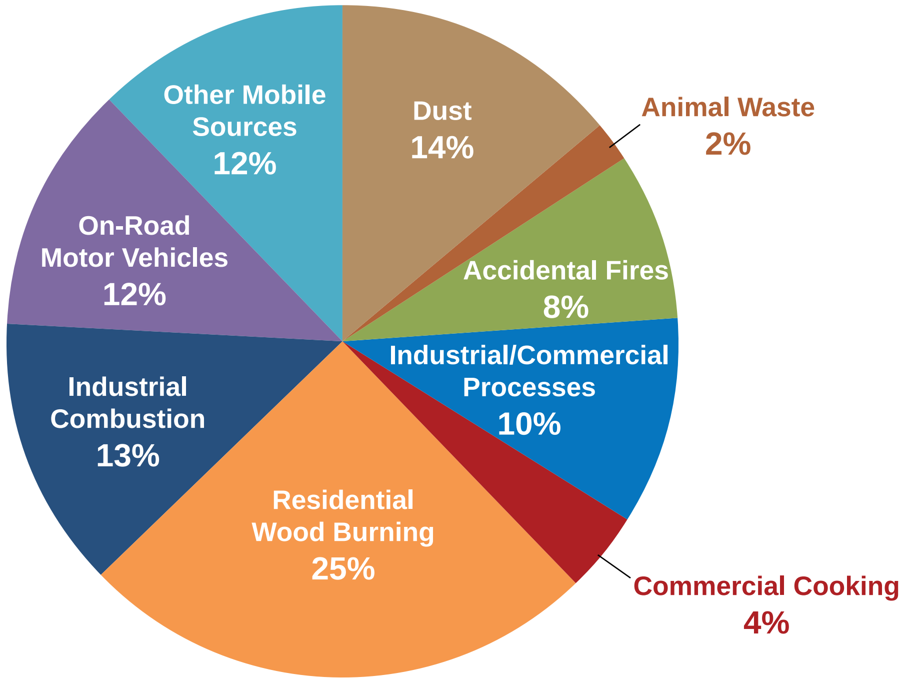


Figure 2-7. **Direct PM_{10} Emissions by Source, Annual Average, 2015 (109 tons/day)**

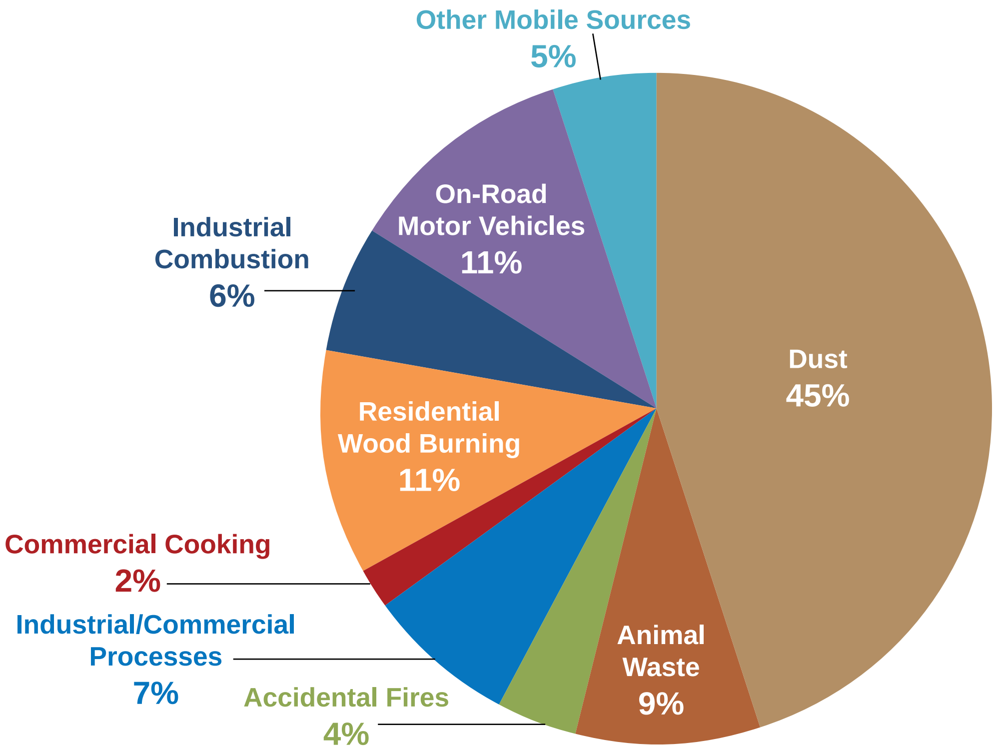


Figure 2-7 shows key sources of directly-emitted PM_{10} in the Bay Area. Whereas dust contributes only modestly to Bay Area $PM_{2.5}$ concentrations, it accounts for a significant portion of PM_{10}, as shown by comparing Figure 2-6 with Figure 2-7.

The reduction in directly-emitted PM, as well as emissions of precursors to secondary PM, has resulted in substantial decrease in PM concentrations and exposure of Bay Area residents to unhealthy PM levels, as discussed in the “Progress in Improving Air Quality and Protecting Public Health” section below.

Source Contributions to Ambient PM Concentrations

Ambient $PM_{2.5}$ derives both from direct emissions and secondary compounds created in the atmosphere. Determining the relative contributions of various sources of direct $PM_{2.5}$ emissions and $PM_{2.5}$ precursors to total PM concentrations is complex. To estimate the overall contribution of various sources, the Air District combines emissions inventory data with the results of chemical mass balance (CMB) analysis, the latter providing information on the relative contributions from source categories contributing to primary and secondary PM.

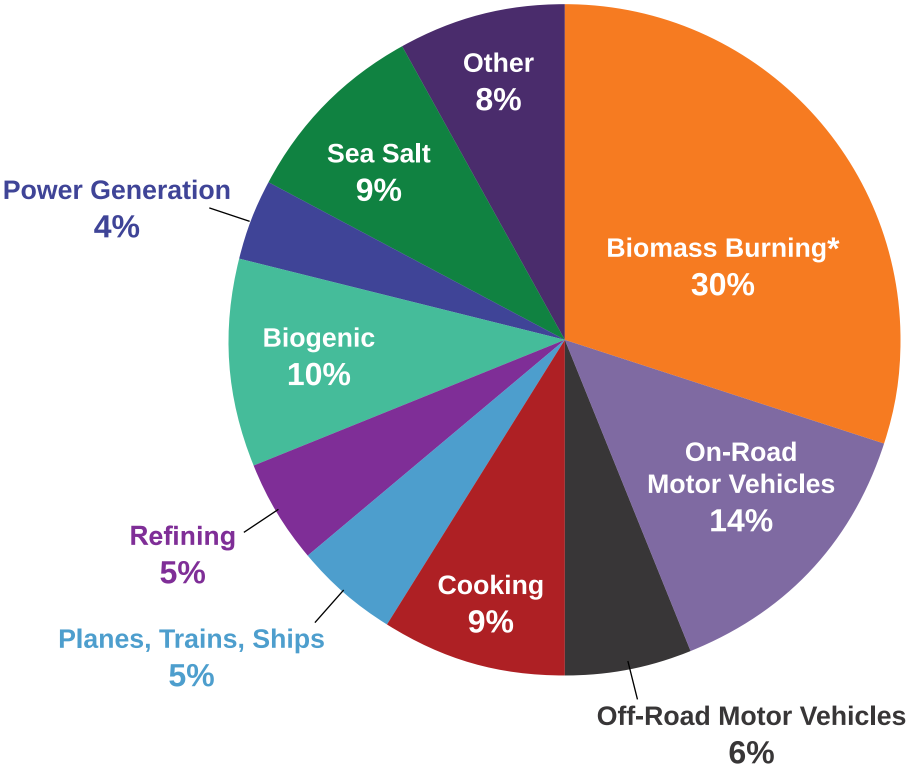
In analyzing PM sources there may be discrepancies between the estimated PM emissions inventory and ambient PM concentrations estimated from CMB analysis. For example, the emissions inventory lists road and windblown dust as significant sources, whereas chemical mass balance analysis shows such dust to be a very small contributor on ambient filters. There are several likely reasons, a primary one being that what gets emitted does not necessarily stay airborne to be sampled. Thus, larger $PM_{2.5}$ particles—those nearly 2.5microns in diameter such as the bulk of geological dust—tend to settle out relatively quickly, whereas smaller particles—those less than 1 micron in diameter including combustion-related $PM_{2.5}$—can stay airborne for days.

...most Bay Area anthropogenic $PM_{2.5}$ derives from combustion – either wood (biomass) burning, or combustion of fossil fuels.

In addition to directly emitted PM, emissions of PM precursors such as NO_x, ammonia and sulfur dioxide contribute to the formation of secondary PM. Combustion of fossil fuels produces NO_x, which combines with ammonia in the atmosphere to form ammonium nitrate and sulfur dioxide (SO_2), which combines with ammonia to form ammonium sulfate. These secondary compounds constitute one-third of Bay Area $PM_{2.5}$ on an annual basis and approximately 40–45 percent during winter peak periods.

Figure 2-8 shows estimated contributions to both primary and secondary annual average $PM_{2.5}$ by source. The contributions in Figure 2-8 differ from those in Figure 2-6 in a number of respects: Sea salt constitutes about 9 percent of Bay Area $PM_{2.5}$, but is not included in the emissions inventory. Emissions of NO_x from motor vehicles contribute significantly to secondary $PM_{2.5}$, namely ammonium nitrate. Because of this, the overall contribution of motor vehicles to $PM_{2.5}$ concentrations is considerably larger than their direct emissions alone. Similarly, refineries emit significant amounts of SO_2, so that their contribution to ammonium sulfate is significant. Also, animals, fertilizers and landfills emit ammonia, which contributes to the formation of ammonium nitrate and sulfate. Nevertheless, most Bay Area anthropogenic $PM_{2.5}$ derives from combustion—either wood (biomass) burning, or combustion of fossil fuels.

Figure 2-8. **Contributions to Annual $PM_{2.5}$ Concentrations in the Bay Area, 2011–2013**



* These estimates derive from combining the source category contribution estimates from 4 sites: Livermore, San Jose, Vallejo, and West Oakland for 2009–2011, with detailed emissions estimates from the Air District's emissions inventory.

Toxic Air Contaminants

Toxic air contaminants are a class of pollutants that includes hundreds of individual airborne chemical species hazardous to human health. Many TACs are commonly present in urban environments. Reducing emissions of TACs and population exposure to these pollutants is a key priority for the Air District.

TACs can cause or contribute to a wide range of health effects. Acute (short-term) health effects may include eye and throat irritation. Chronic (long-term) exposure to TACs may cause more severe effects such as neurological damage, hormone disruption, developmental defects and cancer. ARB has identified roughly 200 TACs, including diesel particulate matter (diesel PM) and environmental tobacco smoke.

Unlike criteria pollutants which are subject to ambient air quality standards, TACs are primarily regulated at the individual emissions source level based on risk assessment. Human outdoor exposure risk associated with an individual air toxic species is calculated as its ground-level concentration multiplied by an established unit risk factor for that air toxic species. Total risk due to TACs is the sum of the individual risks associated with each air toxic species.

Figure 3-7. **2015 Bay Area GHG Emissions: Transportation (Total = 37 MMT CO_2e)**

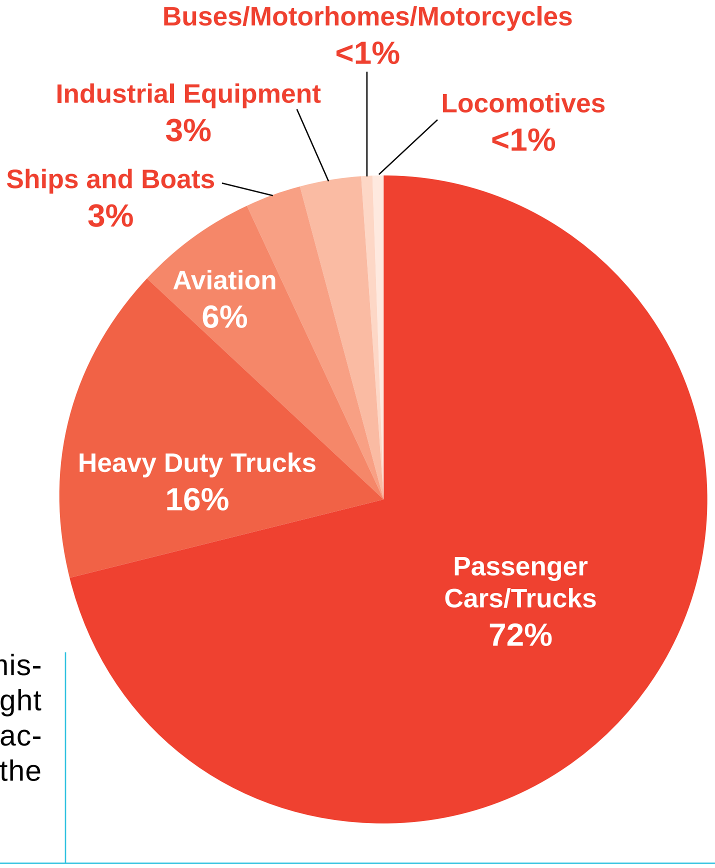


Figure 3-7 shows a breakdown of GHG emissions from transportation by vehicle type. Light and medium-duty cars and trucks currently account for 72 percent of GHG emissions from the transportation sector.

Figure 3-8. **2015 Bay Area GHG Emissions: Stationary Sources (Total = 22 MMT CO_2e)**

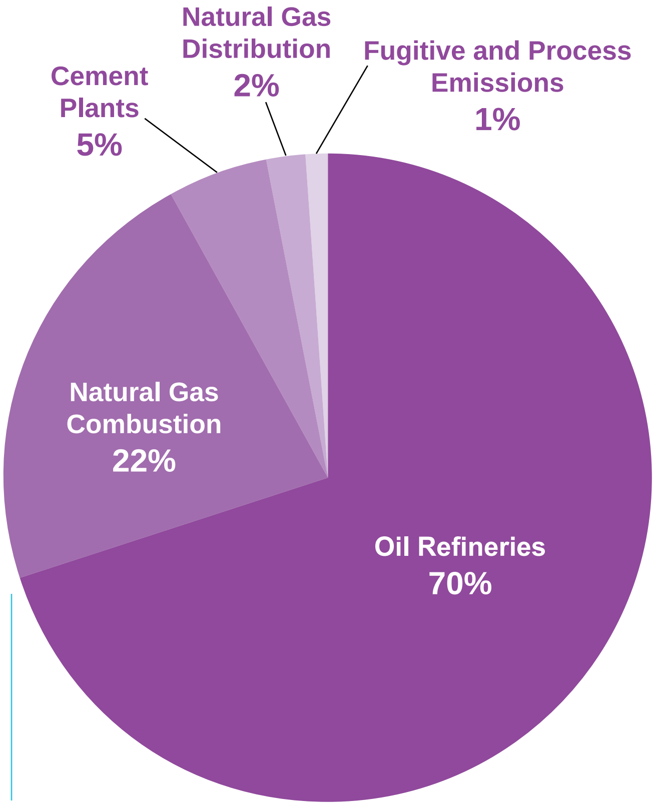


Figure 3-8 provides a breakdown of GHG emissions from stationary sources. The five Bay Area oil refineries account for 70 percent of GHG emissions from stationary sources. The other major stationary source of GHG emissions in the Bay Area is natural gas combustion (22 percent).

Table 3-2 shows Bay Area GHG emissions expressed in CO_2e (i.e., with each pollutant weighted by GWP) by source category for 2015. Note that the total emissions in Table 3-2 (86.5 MMT CO_2e) are greater than shown in the other charts because Table 3-2 includes estimated emissions of black carbon, whereas the other inventory charts and figures do not include black carbon.

Table 3-2. **2015 GHG Emissions (in 100-yr GWP CO_2 Equivalent Metric Tons per Year)**

SOURCE CATEGORY	CO_2e (CH_4, N_2O, HFC/PFC, SF_6)	BC (CO_2e)	Total Emissions by Source (CO_2e)
TRANSPORTATION	**34,630,000**	**790,000**	**35,420,000**
On-Road	30,420,000	330,000	30,750,000
Off-Road	4,210,000	460,000	4,670,000
ELECTRICITY/CO-GENERATION	**12,110,000**	**130,000**	**12,240,000**
Co-Generation	5,790,000	90,000	5,880,000
Electricity Generation	5,040,000	40,000	5,080,000
Electricity Imports	1,280,000	-	1,280,000
BUILDINGS	**8,880,000**	**390,000**	**9,270,000**
Residential Fuel Usage	5,240,000	210,000	5,450,000
Commercial Fuel Usage	3,640,000	180,000	3,820,000
STATIONARY SOURCES	**22,020,000**	**340,000**	**22,360,000**
Oil Refineries	15,470,000	210,000	15,680,000
Natural Gas Combustion	4,870,000	110,000	4,980,000
Natural Gas Distribution*	460,000	-	460,000
Cement Manufacturing	990,000	-	990,000
Fugitive and Process Emissions*	230,000	20,000	250,000
WASTE MANAGEMENT	**2,280,000**	**20,000**	**2,300,000**
Landfills*	1,830,000	20,000	1,850,000
Composting/POTWs*	450,000	-	450,000
FLUORINATED GASES	**3,560,000**	**-**	**3,560,000**
HFCs and PFCs (Com., Indus., Transp.)*	3,470,000	-	3,470,000
SF_6 (Electricity Prod. and Semiconductor Mfg.)*	90,000	-	90,000
AGRICULTURE	**1,220,000**	**170,000**	**1,390,000**
Animal Waste*	740,000	20,000	760,000
Soil Management	280,000	-	280,000
Agricultural Equipment	190,000	40,000	230,000
Biomass Burning	10,000	110,000	120,000
TOTAL EMISSIONS (CO_2e)	84,700,000	1,840,000	86,540,000

*Significant source of super-GHGs

Table 5-10. **Further Study Measures** *(continued)*

Number	Name	Pollutant	Description
Buildings			
FSM_ BL1	Space Heating	NO_X	Research the viability of reducing NO_X emission from furnaces rated above 175,000 BTU/hr that are found in multi-family residential buildings and large commercial spaces.
Agriculture			
FSM_ AG1	Wineries	ROG	Review emissions generated by fermentation at wineries and breweries to determine if reductions can be achieved.

What the 2017 Plan Will Accomplish

To achieve the goals of protecting public health and protecting the climate, the 2017 Plan proposes an integrated, multi-pollutant control strategy to reduce emissions of key air pollutants and greenhouse gases. While achieving the region's long-term air quality and climate protection goals will require aggressive and sustained action by all members of society and all sectors of the economy, the 2017 control strategy focuses on what the Air District can do over the next three to five years to reduce air pollution and to achieve GHG reductions needed by 2020 and to set the region on a path toward the longer-term goals. By addressing all economic sectors and emission source categories consistent with the Air Resources Board's 2014 Scoping Plan, and drawing upon the full range of tools and resources available to the Air District, this control strategy includes all feasible measures that the Air District can take, within its current statutory authority, to reduce emissions of air pollutants and greenhouse gases. The anticipated benefits of the Plan in protecting public health and protecting the climate are discussed below from both a qualitative and quantitative perspective.

Protecting Public Health

To protect public health, the 2017 Plan reinforces the Air District's commitment to focus our air quality efforts on reducing the air pollutants that pose the greatest health risk to Bay Area residents. As noted in Chapter 2, fine particulate matter ($PM_{2.5}$) poses the greatest health risk for Bay Area residents. The control strategy includes a comprehensive set of measures to reduce PM emissions from a wide

> *The 2017 Plan also represents a concerted effort to reduce multiple pollutants from the Bay Area's five oil refineries.*

range of emission sources. For stationary sources alone, the control strategy includes the following measures that will help to reduce emissions of PM and/or PM precursors: SS1, SS4, SS7, SS8, SS11, SS18, SS19, SS24, SS31, SS32, SS33, SS34, SS35, SS36, SS37 and SS38.

The control strategy also focuses on reducing emissions and population exposure in the Bay Area communities that are most impacted by air pollution. For example, the proposed control measures to further reduce emissions of particulate matter and toxic air contaminants from key sources, such as oil refineries (see measures SS1 through SS12), diesel engines (see measures SS32, TR18 and TR19), and wood burning (see measure SS34), will all help to reduce population exposure to the most harmful air pollutants in the impacted communities. To protect these communities, the Air District will also prioritize implementation of measures to reduce toxics from new and existing facilities (SS20 and SS21). In addition to reducing disparities in health risks between communities, the control strategy also aims to advance equity in a broader sense. For example, as discussed above, by promoting urban tree-planting, control measure NW2 can help to clean the air, mitigate local heat island effects, and improve the overall quality of life in impacted communities.

The 2017 Plan also represents a concerted effort to reduce multiple pollutants from the Bay Area's five oil refineries. At least 12 control measures in this Plan are designed to reduce refinery emissions of particulate matter, ozone precursors, toxic air contaminants and GHGs. In addition to directly reducing emissions, the Air District's Refinery Emissions Reduction Strategy also addresses these emissions through monitoring, best practices and health risk assessments. Building upon previous refinery regulations, this set of measures, taken as a whole, constitutes one of the most aggressive strategies to reduce oil refinery emissions in the country.

Emissions of ROG, NO_X and $PM_{2.5}$ have been decreasing steadily over the past several decades, in response to existing regulations and policies, and turnover in the motor vehicle fleet. The 2017 control strategy will provide additional emission reductions, over and above any built-in emission reductions from the existing control program in future years. In aggregate, the proposed control measures are expected to reduce emissions of ROG by 11 tons per day, NO_X by 9.3 tons per day, and $PM_{2.5}$ by 3.1 tons per day in 2030. (Actual emission reductions are expected to be higher, because Air District staff has not yet been able to estimate the emission reduction for a number of measures.)

The estimated health benefits of the reductions in emissions of ozone precursors, particulate matter, and toxic air contaminants from the proposed control strategy as a whole, based on the multi-pollutant evaluation method (MPEM) described in Appendix C, are shown in the "Cases Avoided" column in Table 5-11. The table also provides the estimated dollar value of the health costs and premature mortality that will be avoided as a result of the reduction in emissions, based on the valuations described in Appendix C. The total estimated benefit in terms of reduced incidence of illness and premature mortality is on the order of $736 million per year. Because there is a high cost associated with premature mortality, and exposure to fine particulate matter ($PM_{2.5}$) accounts for nearly all the premature mortality, reductions in emissions of $PM_{2.5}$ and PM precursors (such as ammonia and sulfur dioxide) account for the majority of the estimated value of the health benefits.

Table 5-11. **Estimated Health Benefits and Dollar Value of 2017 Control Strategy**

Health Endpoint	Cases Avoided	Dollar Value
Premature Mortality	76	$700,232,000
Nonfatal Heart Attacks	44	$3,810,000
Hospital admissions	16	$840,000
Asthma Emergency Room Visits	29	$14,000
Chronic Bronchitis	47	$23,645,000
Acute Bronchitis	249	$156,000
Respiratory Symptoms	10,189	$412,000
Lost Work Days	9,128	$2,284,000
Minor Restricted Activity Days	51,403	$4,567,000
Total Estimated Dollar Value		**$735,960,000**

Protecting the Climate

The 2017 Plan expands and deepens the Air District's existing efforts to protect the climate by defining a comprehensive regional climate protection strategy. This strategy will reduce GHG emissions in the near term and serve as a roadmap toward the GHG reduction targets for 2030 and 2050. In addition to moving aggressively within the Air District's statutory authority to limit emissions from stationary sources, the economic sector framework used to develop the proposed control strategy broadens the scope of the Air District's climate protection activities into sectors in which the Air District may have limited authority to adopt regulations, but which are appropriate focuses for Air District policy intervention, such as transportation, energy, waste, agriculture, natural and working lands, buildings and water. In crafting the proposed control measures, Air District staff will apply technical and policy expertise in these sectors that should prove useful in encouraging other entities that have direct control or influence over these GHG emissions to adopt new technologies, policies and approaches needed to fully implement the control strategy.

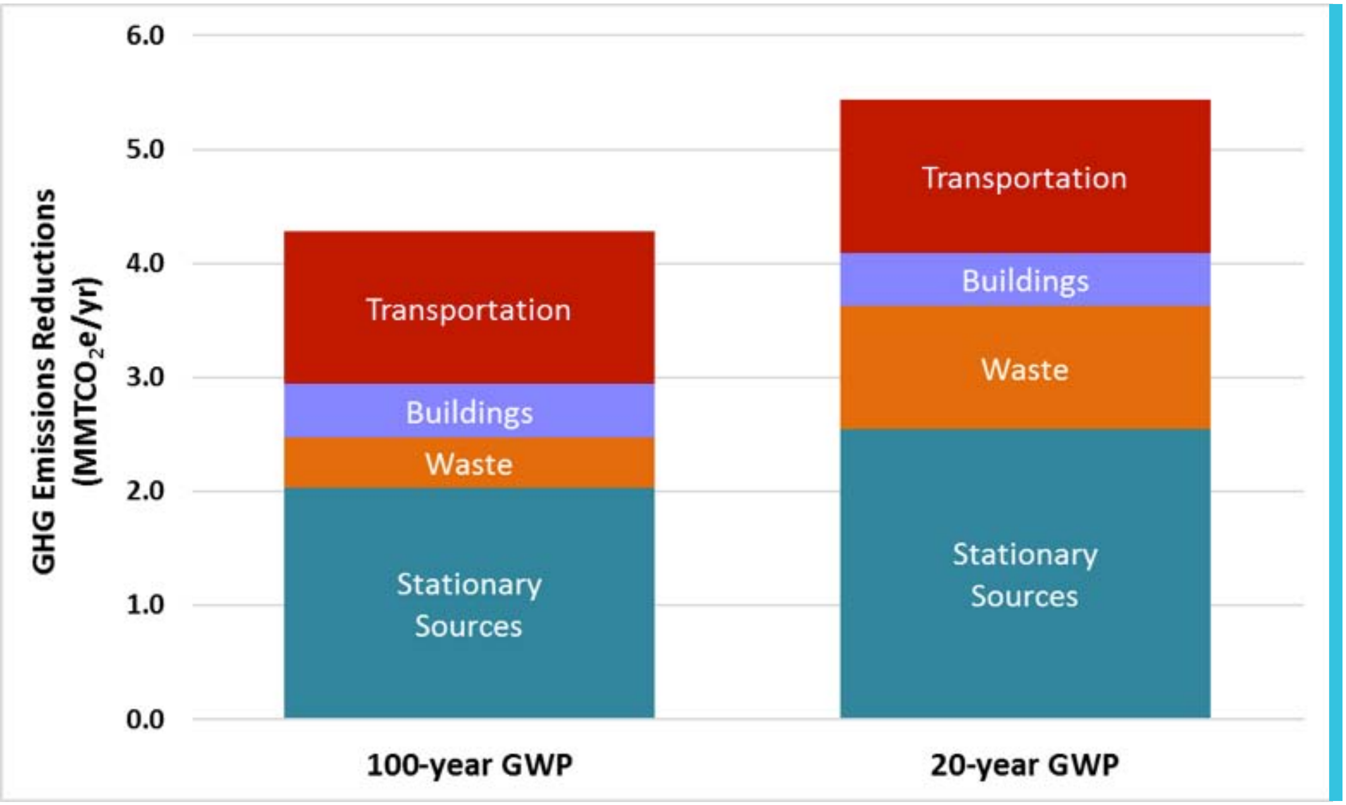
The Air District's GHG reduction efforts to date have primarily focused on reducing emissions of carbon dioxide. Although reducing CO_2 will continue to be a major focus of our climate protection strategy, the 2017 Plan also breaks new ground by emphasizing the importance of moving quickly to reduce emissions of super-GHGs such as methane, black carbon and fluorinated gases.

In the course of developing the 2017 Plan, the Air District collaborated with the UC Berkeley Cool Climate Network to prepare a consumption-based GHG emissions inventory for the region as a whole, as well as for each city and county in the Bay Area, as discussed in Chapter 3. The consumption-based inventory describes the magnitude and composition of GHG emissions embedded in the goods and services consumed by Bay Area residents. This information is already helping to inform local climate planning in the region, and can be used to educate Bay Area residents, agencies, and businesses about effective action they can take to reduce their own GHG footprint.

The estimated reductions in Bay Area GHG emissions from the proposed control strategy, broken down by economic sector, are shown in Figure 5-1. The GHG reduction measures in the proposed control strategy are estimated to reduce approximately 4.4 million metric tons (MMT) of CO_2e per year by 2030, based on 100-year GWP factors. The emissions reductions are estimated to be 5.6 MMT of CO_2e per year by 2030 if the emissions reductions are calculated based on 20-year GWP factors. Emission reductions estimates for individual control measures, for both criteria air pollutants and GHGs, and the approach used to generate those estimates, are described in Appendix H. Please note that, because emission reductions could not be estimated for a number of the control measures, the reductions shown in Figure 5-1 underestimate the total reductions that will eventually be achieved from the control strategy.

Air District staff expects the proposed control measures to provide important GHG reduction benefits, both by directly reducing emissions through their implementation, and also by supporting or stimulating action by others. However, the Air District expects that the full benefit of the proposed measures will ultimately be greater than quantified here. The emission reduction estimates provided here are deliberately conservative.

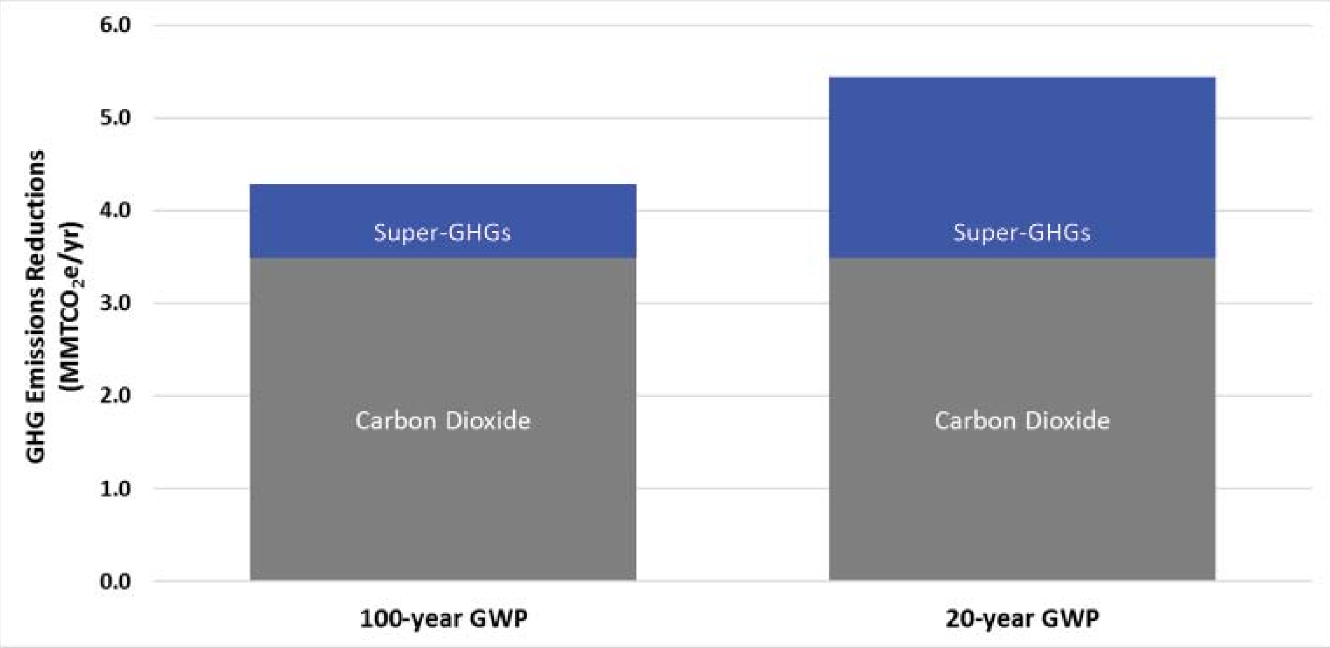
Figure 5-1. **Estimated 2030 GHG Emission Reductions from Control Strategy by Economic Sector**



The analysis uses cautious assumptions about the extent of the measures' direct impacts, and also does not quantify potential secondary effects in supporting activities by other entities. But we believe that the set of control measures proposed in this Plan represents a broad range of effective and appropriate actions that we can take to reduce GHG emissions and to support critical policies and programs implemented by other key actors.

Figure 5-2 shows the estimated Bay Area GHG emissions reductions by climate pollutant. The super-GHG emissions are primarily methane, along with a small amount of HFC emissions. Some control measures will also reduce black carbon (as a component of fine PM); however, black carbon emission reductions are not included in the super-GHG data in Figure 5-2.

Figure 5-2. **Estimated 2030 GHG Emissions Reductions from Control Strategy by Climate Pollutant**



Economists use a term called the "social cost of carbon" to estimate the monetary benefit of reducing GHG emissions...

Economists use a term called the "social cost of carbon" to estimate the monetary benefit of reducing GHG emissions in terms of avoiding or mitigating the global warming and climate change impacts that would otherwise occur. Using a social cost of \$62 per metric ton of CO_2e reduced, per U.S. EPA guidance, the anticipated GHG reductions from the 2017 Plan control strategy will have a value of approximately \$350 million per year (based on the 5.6 MMT per year of GHG reductions using the 20-year GWP values).[18]

The control strategy proposed in the 2017 Plan should be seen as a key element of a broader region-wide effort on the part of public agencies, academic institutions, the business community, and environmental and community groups, and the public to reduce Bay Area GHG emissions and protect the climate. As noted in Chapter 4, *Plan Bay Area,* which was adopted by MTC and ABAG in 2013 and is currently being updated, will play an important role in integrating land use and transportation planning so as to reduce motor vehicle travel. In addition, the local climate action plans that have been adopted by more than 60 cities and counties throughout the Bay Area are another critical element of the overall regional effort to reduce GHG emissions and protect the climate.

The control measures described in this Plan, in combination with the state, regional, and local efforts summarized in Chapter 4, will help to move the Bay Area closer to the trajectory needed to achieve the long-range GHG reduction targets for years 2030 and 2050. The Air Resources Board is also in the process of updating the AB 32 Scoping Plan and estimating the anticipated emissions reductions from that plan. The Air District will continue to work with ARB and other key partners in evaluating the impacts of climate protection programs.

The control strategy described in the 2017 Plan should serve as a solid foundation to guide our efforts to reduce emissions of air pollutants and GHGs over the next three to five years. However, achieving the long-range GHG reduction targets will require a collaborative effort on the part of government agencies, the business community, and Bay Area residents to make fundamental changes to our economy and energy systems, as described in the Vision for 2050 that introduces this document.

Implementation—Key Priorities

To implement the control measures in the 2017 Plan, the Air District will use the full range of its tools and resources. For the purpose of prioritizing the implementation of the control measures in the 2017 Plan, the Air District will consider the potential of each measure to:

- Improve air quality in impacted communities.
- Reduce GHG emissions, especially in the near term (e.g., measures to reduce super-GHG emissions).
- Reduce multiple pollutants on a cost-effective basis (see Table H-1 in Appendix H).
- Serve as a model or example that can be replicated in other regions.

Based upon these criteria, the Air District will prioritize the implementation of control measures so as to maximize progress toward four key themes:

- Reduce emissions of criteria air pollutants and toxic air contaminants from all key sources.
- Reduce emissions of super-GHGs with high global warming potential, such as methane.
- Reduce demand for fossil fuels.
    - Increase efficiency of energy, buildings, and transportation sectors.
    - Reduce demand for vehicle travel, and high-carbon goods and services.
- Decarbonize our energy system.
    - Make the electricity supply carbon-free.
    - Electrify the transportation and building sectors.

Table C-3 shows the reduction in the estimated number of annual cases; i.e., the difference between "then" and "now" for each of the health effects shown in Figure C 1. Table C-3 provides the "best estimate" as well as the lower bound (10th percentile) and upper bound (90th percentile) for an 80 percent confidence interval. The range of values is provided in Table C-3 in order to emphasize that all the health effects figures provided in this analysis are estimates. The numbers in this analysis are intended to convey a sense of overall trends and relative magnitudes, but they are not precise figures.

Figure C-1 shows that the annual numbers of health effects associated with exposure to air pollutants in the Bay Area has dropped dramatically by more than half. Of particular interest, premature deaths related to air pollution has decreased from an estimated 8,300 per year to an estimated 2,500 per year. For comparison, the total number of annual deaths in the Bay Area is about 45,000, and the annual number of transportation-related deaths in the Bay Area is 400 to 500.

Life expectancy is widely regarded as an indicator of the overall health of a given population. Life expectancy measures the average number of years a baby born today would live given the present distribution of age-specific probabilities of death. Premature mortality is a measure of unfulfilled life expectancy. The reduction in mortality risk as shown in Figure C-1 can be expressed in terms of increased life expectancy. Bay Area life expectancy increased by 6 years, from 75.7 in 1990 to 81.8 in 2012, due to a variety of factors. Of the overall increase in life expectancy during this period, improvements in air quality can be credited with extending average life expectancy in the Bay Area by about one year. Thus, approximately one-sixth of the improvement in Bay Area average life expectancy since 1990 may be attributable to cleaner air. (See MPEM Technical Document for further details.)

The vast majority of the mortality risk related to air pollution is due to exposure to fine particulate matter ($PM_{2.5}$), shown as the combination of diesel $PM_{2.5}$ and other anthropogenic $PM_{2.5}$ in Figure C-1. Several robust epidemiological studies have shown that $PM_{2.5}$ concentrations in a given area affect the death rate. The studies are based on data sets where the health and health-relevant information for a set of people from different areas has been collected for an extended period. These records allow the estimation of mortality rates for various areas, where the rates are adjusted for key factors such as age, gender, smoking, and obesity. The studies compared the adjusted death rate for each area with the average PM concentrations in the area. These showed clear correlations, with higher average $PM_{2.5}$ correlated with lower life expectancy.[8]

After reviewing the literature, a risk factor is used based on the assumption that every 1.0 µg/m³ reduction in $PM_{2.5}$ concentration results in a one percent reduction in mortality rate for individuals

Table C-3. Reductions in annual cases, "then" to "now" including an 80 percent confidence interval.

	Mortality	Cancer Onset	Respiratory Hospital Admissions	Cardiovascular Hospital Admissions	Chronic Bronchitis	Nonfatal Heart Attacks	Asthma Emergency Room Visits
Best Estimate	5,500	120	240	900	2,900	2,600	2,200
10th Percentile	2,200	50	120	700	1,100	1,300	1,500
90th Percentile	10,100	230	420	1,100	4,400	3,600	2,900

over 30 years old.[9] For the MPEM, the change in premature mortality from $PM_{2.5}$ was calculated by estimating the percentage change in mortality from a given change in $PM_{2.5}$ concentration and applying that to the annual deaths to persons over 30 years old. Currently, Bay Area $PM_{2.5}$ concentrations average about 8.7 µg/m^3, or about 5.7 µg/m^3 above natural background levels. Thus, total elimination of anthropogenic $PM_{2.5}$ is estimated to reduce the death rate by about 5.7 percent for those over 30, or about 2,500 deaths per year.

Although research is still on-going to determine the precise biological mechanisms through which $PM_{2.5}$ is associated with increased mortality, it appears that cardiovascular problems, such as heart attacks, are the leading cause (U.S. EPA 2009). Although diesel PM is the leading air toxic in the Bay Area, it should be noted that perhaps only about 10 percent of these PM-related deaths are linked to diesel exhaust. Other sources of PM, such as wood smoke, cooking, and secondary formation of PM from precursors such as NO_X, SO_2, and ammonia, collectively account for most of the ambient PM, and PM-related mortality, in the Bay Area. To the extent that diesel PM does contribute to premature deaths, it appears to be primarily due to the mechanisms mentioned above. Cancer accounts for a smaller number of total deaths related to air pollution. The total annual number of cancer deaths, including lung cancer, related to exposure to diesel PM in the Bay Area, is approximately 20-25 per year. Thus, mortality related to exposure to fine PM (including diesel particles) appears to be associated much more with cardiovascular problems than with cancer.

Summary of Costs and Disbenefits

Air pollution imposes costs on society in terms of public health, the environment, and the economy. Approximations can be made for the direct costs of treatment for pollution-related health effects, as well as indirect costs based upon people's willingness to pay to avoid those health effects. Table C-4 presents a list of health effects and the estimated dollar value of these effects on a per-case basis. For GHGs, a value of $62 metric ton of CO_2-equivalent emitted is used for the overall social cost related to the anticipated impacts of

Table C-4. **Estimated dollar value per case for key health effects related to Bay Area air pollution.**

Health Effect	Unit Value (Cost per Incident, 2015 dollars)
Mortality (all ages)	$8,800,000
Chronic Bronchitis Onset	$476,117
Respiratory Hospital Admissions	Age 65 < : $55,305 Age 65 > : $48,901
Cardiovascular Hospital Admissions	Age 65 < : $65,178 Age 65 > : $56,060
Non-Fatal Heart Attacks	$82,580
Asthma Emergency Room Visits	$478
Acute Bronchitis Episodes	$598 for a 6-day illness period
Upper Respiratory Symptom Days	$40
Lower Respiratory Symptom Days	$25
Work Loss Days	Daily Median Wage by County ($186 to $278)
School Absence Days	$103
Minor Restricted Activity Days	$85
Cancer	$3,700,000
Social Cost of GHG Emissions	$62 per metric ton ($CO_2$ equivalent)

D) $PM_{2.5}$ base-case validation

As with ozone, the $PM_{2.5}$ base-case simulation was validated using measurements to ensure that results adequately represented observed levels. Simulated 24-hour average $PM_{2.5}$ levels were compared against observed 24-hour average $PM_{2.5}$ at every observation station in the modeling domain, day by day, for January 2–15, 2012. Once again the average of simulated values at observation station locations for selected subdomains such as the Bay Area, San Joaquin Valley and Sacramento were compared to the average of observations for the respective subdomains. Finally, the simulated annual average was compared to the observed annual average for the stations within each subdomain. Graphical displays of evaluated fields and statistical measures such as bias, error, root mean square error and index of agreements were generated.

Generally, model performance is reasonable. Again, special attention is given to the Bay Area and Delta region. Station-by-station comparisons are shown in Figures D-6a through D-6d for four selected Bay Area stations: San Jose, San Francisco, Oakland and Vallejo for January 2–15, 2012. These stations historically experience high $PM_{2.5}$ concentrations during winter months.

The observed day-to-day variance in PM was effectively simulated by the model at all four locations, indicating that the meteorological conditions that impacted PM formation during this period were generally captured well. The magnitudes of peak simulated $PM_{2.5}$ were close to peak observations at San Jose and Vallejo, but were overestimated in San Francisco and underestimated in Oakland during the January 9–12 episode. This could be due to the inherent uncertainty in comparing a point measurement to a 4x4 km grid volume estimate at urban locations with complex emission patterns.

The model was also evaluated using observed concentrations of key precursors such as NO_X, VOCs, ammonia, organic and inorganic PM species and SO_X. The performance of the model for these species was also reasonable (not shown).

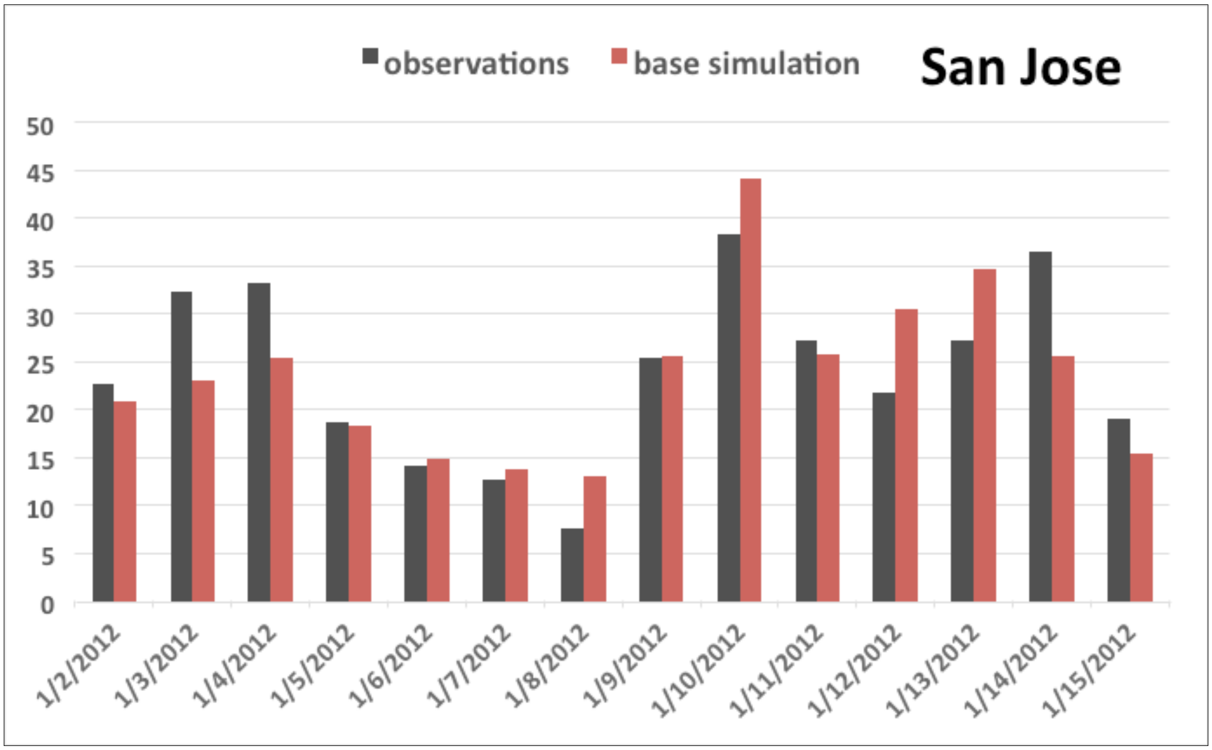


Figure D-6a. Simulated and observed 24-hour average $PM_{2.5}$ concentrations (µg/m^3) at the San Jose air monitoring station for January 2–15, 2012

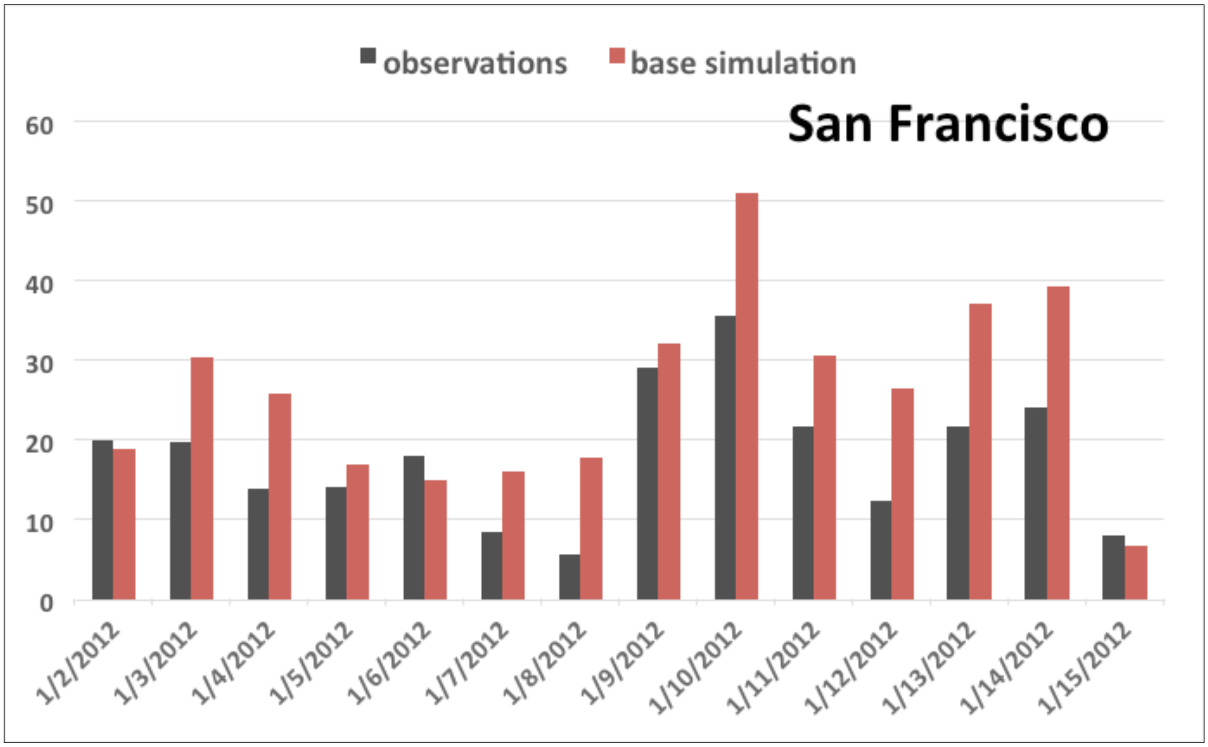


Figure D-6b. Simulated and observed 24-hour average $PM_{2.5}$ concentrations (µg/m^3) at the San Francisco air monitoring station for January 2–15, 2012

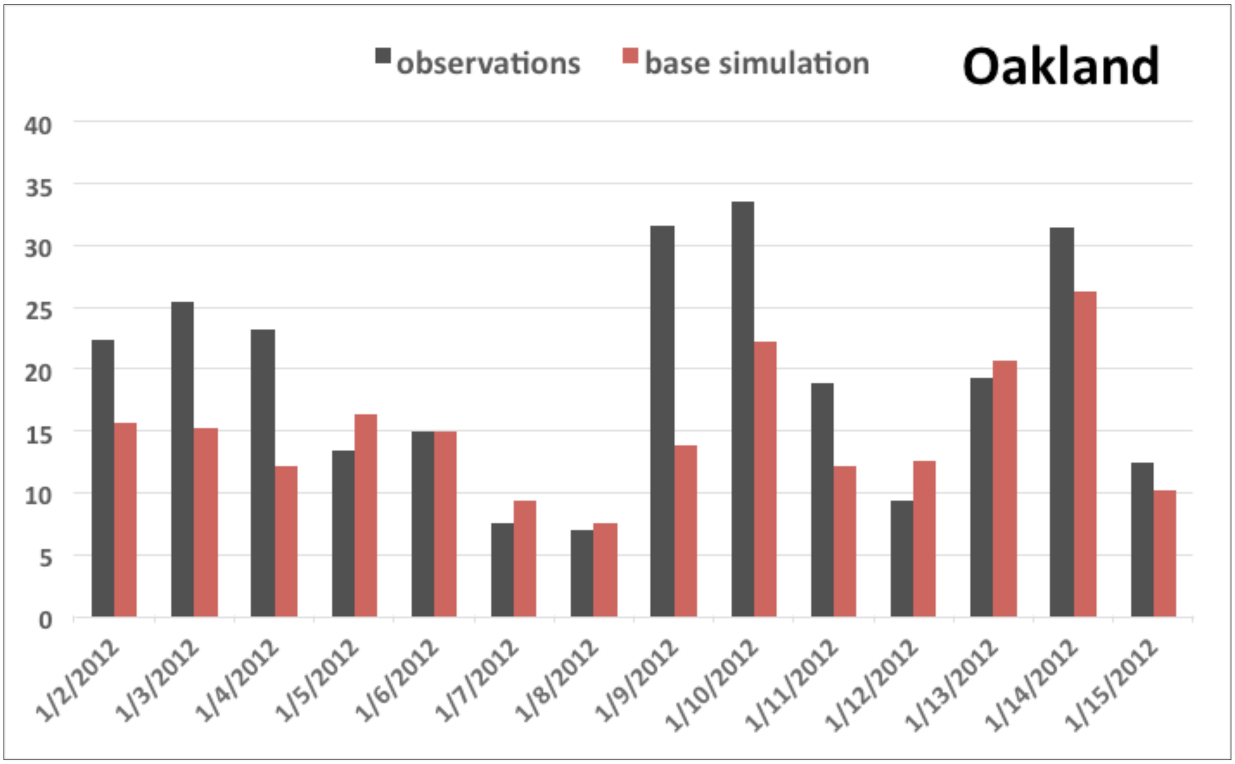


Figure D-6c. Simulated and observed 24-hour average $PM_{2.5}$ concentrations (µg/m^3) at the Oakland air monitoring station for January 2–15, 2012

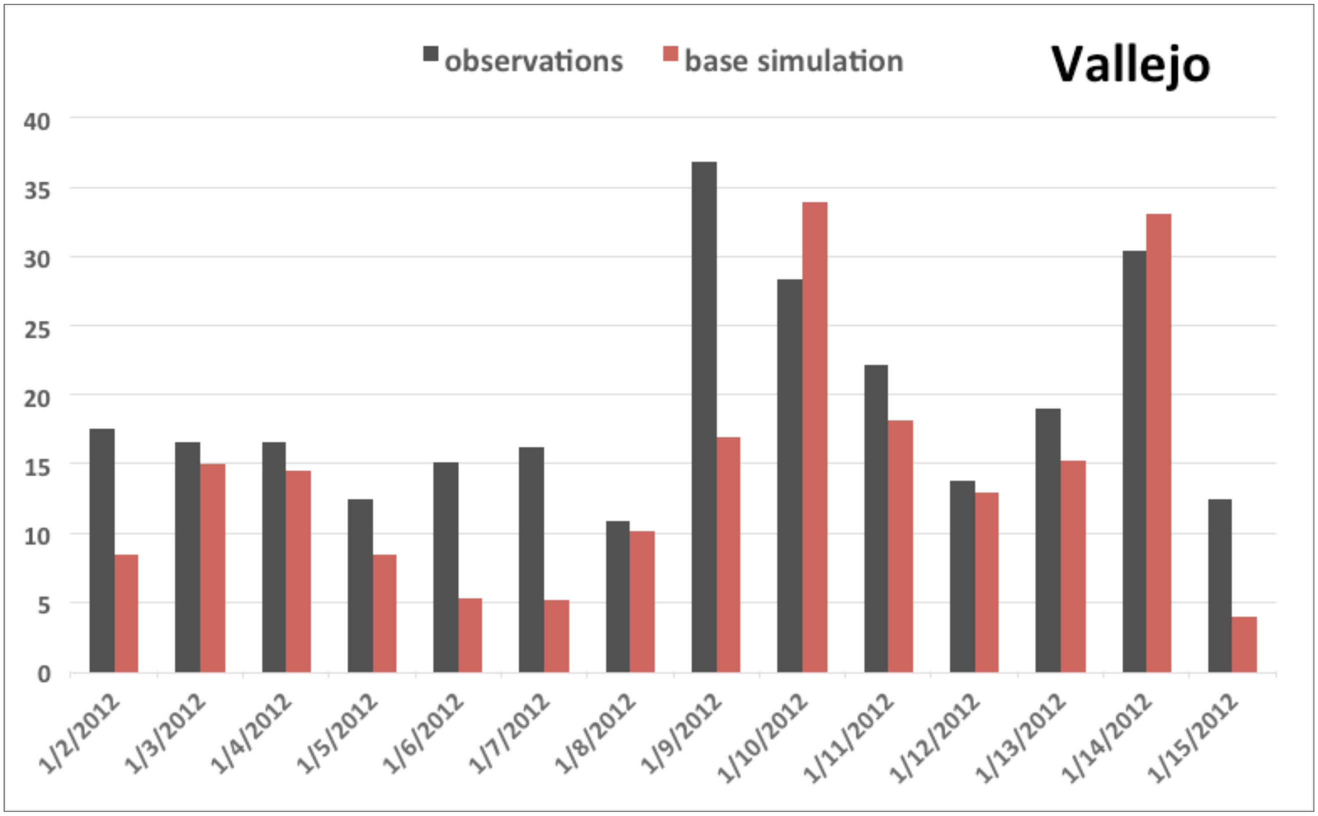


Figure D-6d. Simulated and observed 24-hour average $PM_{2.5}$ concentrations (μg/m^3) at the Vallejo air monitoring station for January 2–15, 2012

E) $PM_{2.5}$ sensitivity simulations

Six sensitivity simulations were conducted for 2–15 January 2012, with 20 percent across-the-board reductions in Bay Area anthropogenic NO_X, VOC, ammonia, SO_X, directly emitted PM and all these combined. Results from these sensitivity simulations were compared to the base-case simulation over the entire Bay Area, but the following discussion is limited to the four Bay Area stations with historically high PM mentioned above.

Among the five anthropogenic species selected, a reduction in directly emitted $PM_{2.5}$ is the most effective in reducing ambient $PM_{2.5}$ concentrations, with a 20 percent reduction in PM emissions resulting in 4–12 percent reductions in $PM_{2.5}$ concentrations at most Bay Area stations on most winter simulation days (Figures D-7a through D-7d). While reductions at San Francisco, Oakland and San Jose are at the upper range of this interval, the reduction at Vallejo is at the lower range because of its proximity to the heavily polluted Central Valley and the influence of transported pollutants from the Valley, evident in Figure D-3.

NO_X, VOC, ammonia and SO_X reductions have small influences as they are precursors of secondary $PM_{2.5}$ (chemically produced in the atmosphere), which requires favorable meteorological conditions, ideal concentrations, and time to form. A 20 percent reduction in emissions of these species each results in less than a 1 percent reduction in $PM_{2.5}$ concentrations at most Bay Area stations on most winter days.

A 20 percent reduction in total anthropogenic emissions results in the highest $PM_{2.5}$ reductions, higher than the 20 percent direct PM-only reduction case because of the contribution of reductions in secondary PM.

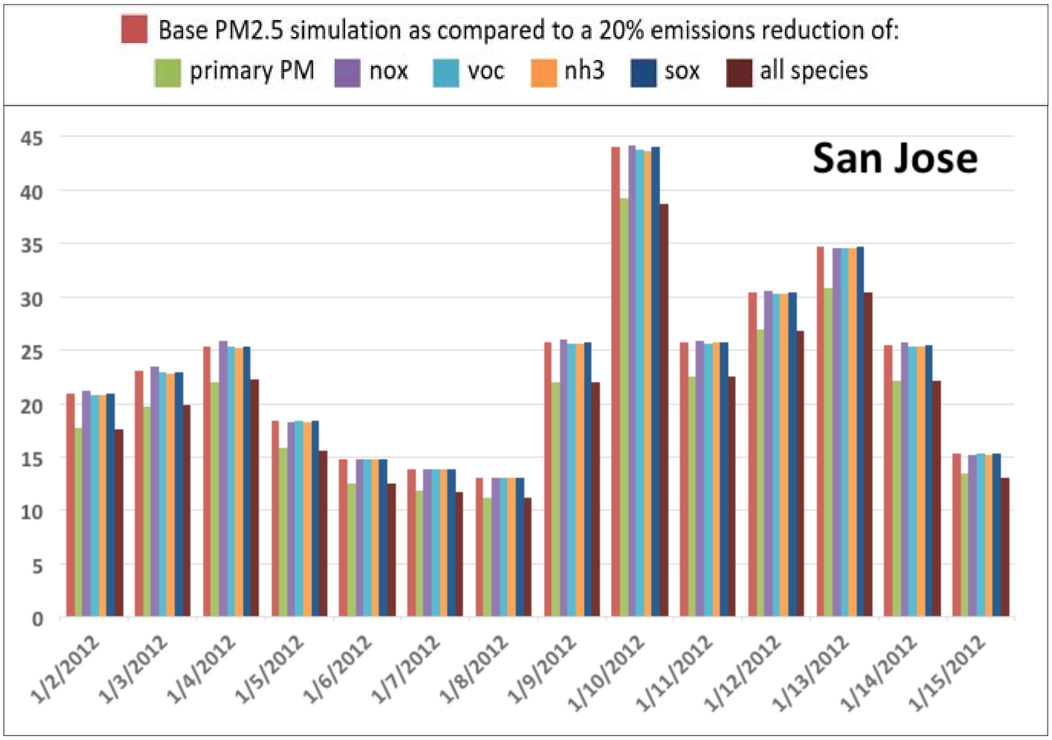


Figure D-7a. Simulated 24-hour average $PM_{2.5}$ concentrations (µg/m^3) at the San Jose air monitoring station for January 2–15, 2012, for the base case and six control cases; control cases include 20% across-the-board anthropogenic emission reductions for directly emitted PM, NO_x, VOC, ammonia, SO_x and all these combined.

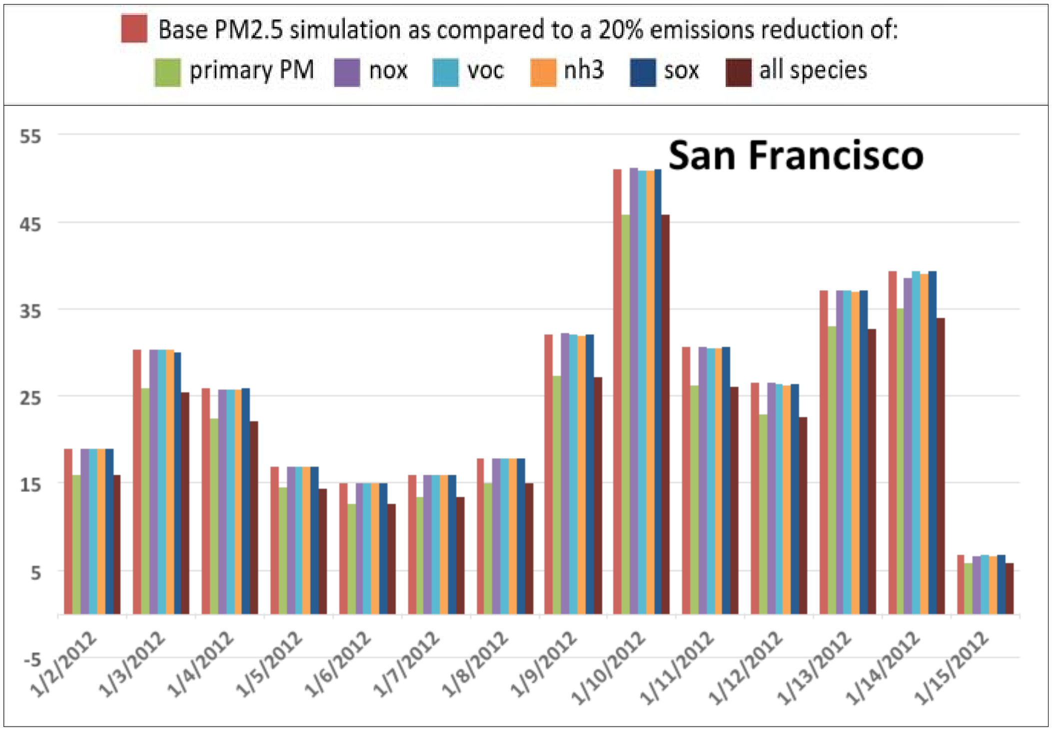


Figure D-7b. Simulated 24-hour average $PM_{2.5}$ concentrations (µg/m^3) at the San Francisco air monitoring station for January 2–15, 2012, for the base case and six control cases; control cases include 20% across-the-board anthropogenic emission reductions for directly emitted PM, NO_x, VOC, ammonia, SO_x and all these combined.

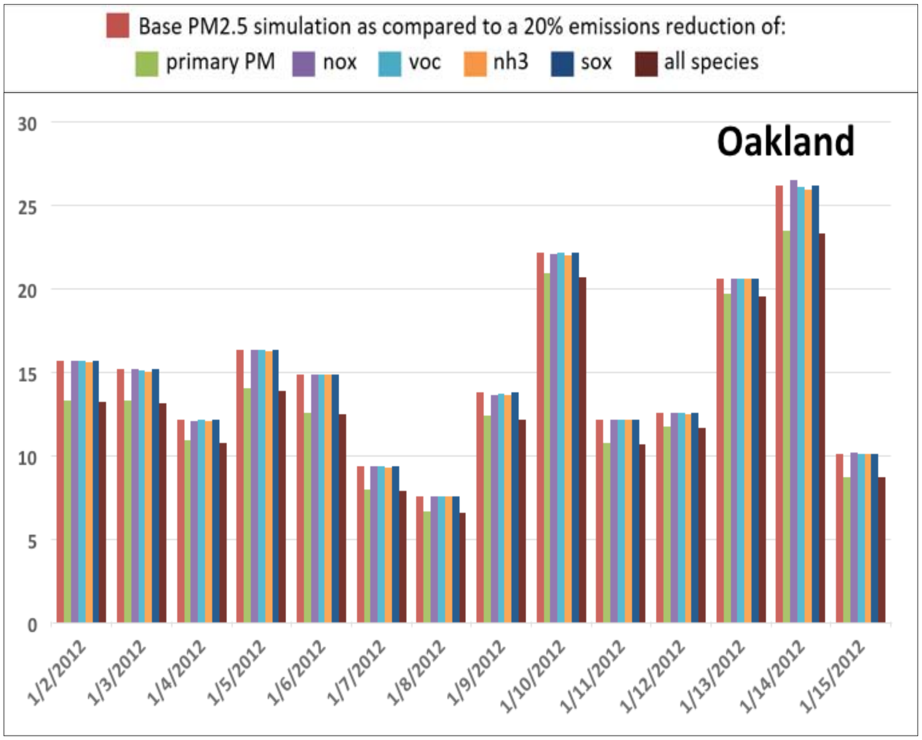


Figure D-7c. **Simulated 24-hour average $PM_{2.5}$ concentrations (µg/m^3) at the Oakland air monitoring station for January 2–15, 2012, ,for the base case and six control cases; control cases include 20% across-the-board anthropogenic emission reductions for directly emitted PM, NO_x, VOC, ammonia, SO_x and all these combined.**

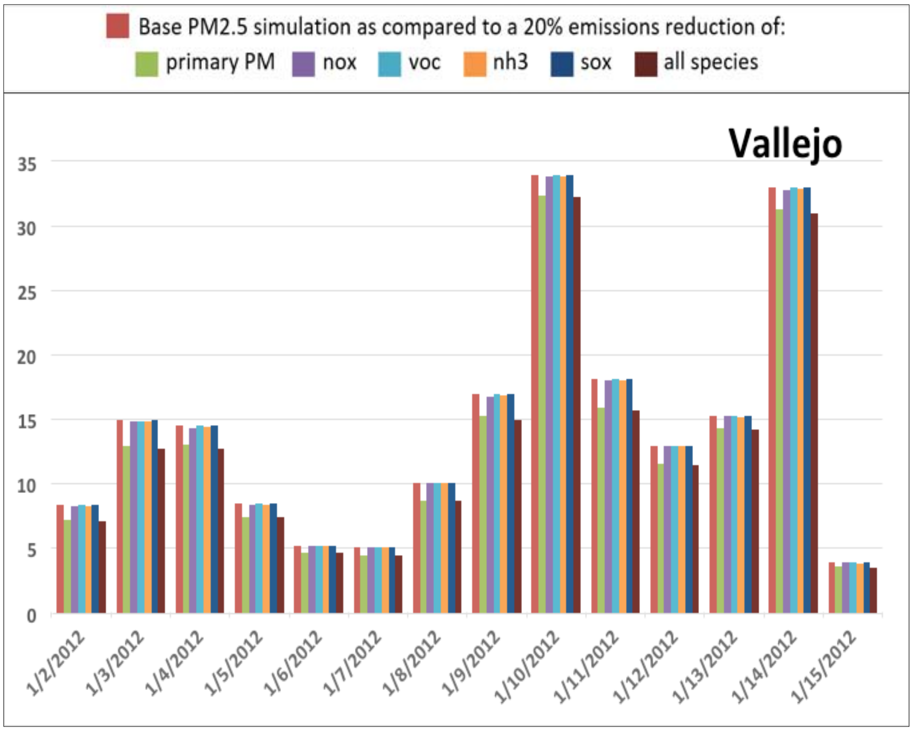


Figure D-7d. **Simulated 24-hour average $PM_{2.5}$ concentrations (µg/m^3) at the Vallejo air monitoring station for January 2–15, 2012, for the base case and six control cases; control cases include 20% across-the-board anthropogenic emission reductions for directly emitted PM, NO_x, VOC, ammonia, SO_x and all these combined.**

SPARE THE AIR
COOL THE CLIMATE

A BLUEPRINT FOR CLEAN AIR AND CLIMATE PROTECTION IN THE BAY AREA

BAY AREA
AIR QUALITY
MANAGEMENT
DISTRICT

FINAL 2017 CLEAN AIR PLAN

VOLUME 2

April 19, 2017

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SS9: Enhanced NSR Enforcement for Changes in Crude Slate

Brief Summary:
This measure would enhance the Air District's New Source Review (NSR) permit program to ensure that refineries are complying with all applicable NSR permit requirements when they change the type of crude oil they process, i.e. changes to the crude slate. This requirement would compel refineries to submit a permit application providing details of any significant change in crude slate, which would allow the Air District to review the change and determine whether it is subject to NSR requirements. Requiring a review of all such significant crude slate changes will allow the Air District to evaluate such changes in detail and ensure that they will comply with applicable NSR permitting requirements.

Purpose:
To ensure compliance with NSR program requirements.

Source Category:
Stationary Source – petroleum refineries

Regulatory Context and Background:
The Air District's NSR program is a comprehensive air permitting program that applies to a wide range of stationary source facilities within the Air District's regulatory jurisdiction. The program requires a facility to obtain a permit and implement state-of-the-art air pollution control technology whenever a facility installs a new source of air emissions or makes a modification to an existing source.

The Air District's NSR program is set out in Regulation 2, Rule 2 (Rule 2-2) and is the Air District's fundamental permitting requirement for regulating criteria pollutant emissions. It requires facilities to obtain an NSR permit for any new or "modified" source of air emissions, and to satisfy a number of air pollution control requirements in order to be eligible for the permit. [1] These requirements vary somewhat depending on the pollutant involved, being somewhat more stringent for pollutants for which the region is not in attainment of the applicable ambient air quality standards (non-attainment pollutants) and somewhat less stringent for pollutants for which the region is in attainment of the applicable ambient air quality standards (attainment pollutants).

This control measure is designed to ensure that refineries comply with applicable NSR permitting requirements when they change the types of crude oil – known as the refinery's

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[1] "Modified source" is defined in Regulation 2-1-234 as (i) any physical change, change in the method of operation, increase in throughput or production, or other similar change to a source that will result in an increase in the source's permitted emissions (or for "grandfathered" sources that are not subject to any permit limits, in increase in the source's physical capacity to emit air pollutants); or (ii) for sources at "major" facilities, which includes all Bay Area refineries, any change that will result in a "significant" increase in the source's actual emissions as defined in EPA's federal NSR regulations.

“crude slate” - that they process.[2] Concerns have been raised that refineries may be making changes associated with moving to new crude oil slates that are subject to NSR permitting requirements, but without obtaining NSR permits or complying with the substantive requirements of the NSR program. A situation could arise where a refinery makes a physical change or change in its method of operations associated with a change in crude slate that meets the definition of a “modification” and would thus require the refinery to obtain an NSR permit under Rule 2-2 and implement the NSR program requirements before making the change. If a refinery makes such a “modification” associated with crude slate changes without applying for or obtaining an NSR permit, it may be difficult or impossible for the Air District (and the public) to discover that the modification was made. Refineries are large, complex operations, and any modifications associated with crude slate changes may be relatively subtle and not immediately obvious.

In 2000, the Air District added the term “alteration” in Regulation 2, Rule 1 (Rule 2-1) Section 233, defined as a change at a source that does *not* increase emissions and is therefore not a “modification” (i.e., a change that does increase emissions). Rule 2-1 Section 301 requires facilities to obtain a permit before making either an “alteration” or a “modification,” and so a permit is required for all such changes, whether they increase emissions (a modification) or do not increase emissions (an alteration). In this manner, *all* changes at a facility that may impact emissions require a permit review, which allows the Air District to determine whether or not they are subject to NSR requirements.

Air District staff is investigating potential amendments to Rule 2-1 to expand the definition of “alteration” to include any significant crude slate change at a petroleum refinery. A crude slate change that increases emissions would be a “modification,” and a crude slate change that does not increase emissions would be an “alteration.” In both cases the refinery would need to obtain a permit before making the change. If the refinery believes that the crude slate change will involve an emissions increase (i.e., will be a “modification”), it can apply for an NSR permit and implement the NSR requirements as it would for any other modification. If the refinery believes that the crude slate change will not involve an emissions increase (i.e., will be an “alteration”), it can apply to have the change permitted as an alteration, which is not subject to NSR. The Air District will then review the application to determine whether there will in fact be any emissions increase or not. If the Air District confirms that there will not be any increase, it will issue a permit and authorize the change as an alteration. If the Air District finds that there will be an increase, however, it will require the change to be treated as a modification and will require the refinery to implement the NSR requirements as a condition to making the crude slate change.

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[2] The term “crude slate” refers to the mix of crude oil types that a refinery processes, and it reflects various characteristics of the crude oil such as sulfur content and density. The crude slates being refined by Bay Area refineries have been changing recently, and they are expected to continue to change in the future as California’s crude oil resources in the Central Valley start to become depleted and refineries look to other sources of crude oil.

Implementation Actions:
The Air District would revise the definition of "alteration" in Rule Section 2-1-233 to clarify that any significant crude slate change is an alteration, such that refineries will need to obtain Air District approval before making such a change. The approval process will allow the Air District to review the change and determine whether it is subject to NSR permitting requirements, and if so, to ensure compliance with any applicable NSR requirements.

Emission Reductions:
This proposed revision is primarily aimed at improving compliance with and enforcement of the Air District's NSR program; it is difficult to quantify the extent of any additional emission reductions associated with such revisions. In situations where a refinery making a crude slate change would have complied with all NSR permitting requirements anyway, the proposed amendment would have essentially no impact. If refineries are making crude slate changes subject to NSR without complying with the regulations, then better enforcement to require the refineries to implement these requirements - as called for in this measure - will have substantial emission reduction benefits.

Exposure Reductions:
Emissions from the Bay Area's five major oil refineries have been steadily decreasing over the past several decades, however, refineries are major sources of criteria air pollutants, TACs, and GHGs. Refineries are also located in impacted communities, including in Richmond. In October 2014, the Air District Board of Directors adopted a Refinery Emissions Reduction Resolution, which established a goal of reducing refinery criteria air pollutant emissions by 20 percent or as much as feasible by 2020. In response to that directive, the Air District has developed a Bay Area Refinery Emissions Reduction Strategy. The Refinery Strategy ensures that refineries are taking the strongest feasible steps to reduce emissions and minimize their health impacts on neighboring residents and the region as a whole. This measure is one of twelve control measures in the 2017 Plan that make up the Refinery Strategy.

Emission Reduction Trade-Offs:
None identified at this time.

Costs:
This measure would entail compliance costs, however, they would not be new costs imposed by additional regulations; they are simply existing compliance costs. These costs may be viewed as "additional" by refineries if they have not been complying with existing regulations, and therefore incurring compliance costs of the existing regulation. The extent of any such compliance costs is unknown, given that the scope of any such non-compliance is unknown.

Co-Benefits:
None.

Issue/Impediments:
None.

Multi-Pollutant Evaluation Method
Technical Document
2016 Update

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November 2016
(Updated version of June 2009 document)

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Executive Summary

The Bay Area Air Quality Management District (District) is preparing the Bay Area 2016 Clean Air Plan (CAP) to update its previous 2010 CAP, as required by the California Health & Safety Code. The 2016 CAP will serve as a multi-pollutant plan to protect public health and the climate. The CAP will propose a control strategy designed to reduce ambient concentrations of four types of pollutants: ground-level ozone, particulate matter, air toxics, and greenhouse gases (GHGs). These pollutants differ in fundamental ways in terms of their emission sources, atmospheric formation, chemical composition and health effects.

This document describes a multi-pollutant evaluation method (MPEM) that the District developed to help analyze and compare potential emission control measures on a multi-pollutant basis for the 2016 CAP. Air pollution imposes a range of negative health impacts and economic and social costs on the Bay Area. In developing the CAP control strategy, District staff used the MPEM to help analyze how potential control measures would reduce these negative impacts on public health and the climate (i.e., anticipated impacts from global warming) and to estimate the associated cost savings of the avoided negative impacts.

The MPEM has been used to:

- Estimate how reductions of each pollutant for a given control measure will affect ambient concentrations, population exposures, and health outcomes related to that pollutant;
- Monetize the value of total health benefits of reductions in PM2.5, ozone and certain carcinogens, and the social value of greenhouse gas reductions that would be reduced by each potential control measure; and
- Evaluate and compare the estimated benefit of potential control measures based upon the value of each measure in reducing health costs from air pollutants and environmental/social impacts related to climate change.

MPEM Foundation

The MPEM is based upon well-established studies and methods that have been used by the EPA, ARB, and other entities to quantify and monetize the health benefits associated with:

- The Clean Air Act (US EPA – 1999)
- Attainment of the ozone NAAQS in California (Ostro et al. – 2005)
- ARB Goods Movement Plan, on-road truck rule, etc. (ARB – 2006)
- Attainment of NAAQS in South Coast & San Joaquin Valley (Hall et al. – 2008)
- South Coast 2007 AQMP (South Coast AQMD)

The MPEM also draws heavily from the US EPA BENMAP program, as well as Office of Environmental Health Hazard Assessment (OEHHA) documents, for coefficients, concentration-response (C-R) functions, and uncertainty estimates.

The MPEM builds upon established precedents embedded in these studies, but goes beyond them by:

- Using computer models to estimate how ambient concentrations of each pollutant are affected by changes in emissions of the pollutants or their precursors; and
- Estimating a value for greenhouse gas emission reductions, expressed in cost ($/ton) of CO2-equivalent reduced.

Caveats and Constraints

The multi-pollutant evaluation methodology is meant to serve as a tool to help guide air quality planning and policy. Inevitably, judgment has been exercised in developing the method, balancing completeness against practicality, and being health-protective against the uncertainty in health effects. Key choices in developing this method include:

- which pollutants to include (Section 1.3.1)
- which health endpoints to include (Sections 1.3.2 & 4.6)
- where to set health effects thresholds (Section 1.3.4)

The MPEM does not include all air pollutants. To avoid undue complexity, we limited the pollutants in the methodology to those that EPA analysis of health studies suggests cause the greatest harm. Among the six criteria pollutants, only ozone and PM are included in the MPEM; these are the two criteria pollutants for which the Bay Area does not yet attain all standards. The Bay Area attains all current standards for the other criteria pollutants (CO, SO2, NO2, and lead). It should be noted, however, that for all the criteria pollutants, there may still be health effects at ambient concentrations even below the current standards.

Toxic air contaminants are a separate category of pollutants. Although the California Air Resources Board has identified nearly 200 toxic air contaminants, in the MPEM we focus on five toxic compounds that together account for over 90% of the estimated cancer risk from air toxics in the Bay Area. Likewise, there are dozens of greenhouse gases that contribute to global warming, but we have elected to focus on the “Kyoto Six” GHGs that have been identified by the Intergovernmental Panel on Climate Change (IPCC) as the major culprits in global warming. The “Kyoto Six” GHGs include carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride.

District staff believe that the MPEM captures most of the key health effects from Bay Area air pollution. However, it is important to note that some health effects are not included in the MPEM, either because the link between the pollutant and the health effect is not yet clearly established or because we lack the data to complete each of the five steps in the methodology described below. Furthermore, even for the health effects that are included, the per-incidence cost estimates may not fully capture all costs associated with a given illness or impact. Likewise, in the case of greenhouse gases (Section 5.3), we suspect that our estimated value for one ton of greenhouse gas reduced (CO2-e) does not fully capture all potential impacts and costs related to climate change and global warming.

In developing the methodology, District staff grappled with many technical issues that are described in the body of this document. Key simplifying assumptions include the following:

- The emissions reductions for each control measure will be geographically distributed on the same basis as the distribution of emissions of each pollutant in the District's emissions inventory. For example, if we estimate that a control measure would reduce one ton of NOx, we then distribute the NOx emission reductions across Bay Area grid cells in the same proportion as the overall NOx inventory is distributed across those grid cells. (Section 1.5)
- For purposes of estimating population exposure (Step 3 below), full-time (24/7) "backyard" exposure is assumed, even though we realize that people do not spend all of their time at home and in their yards. (Section 3.2)

The Five Key Steps

Although the MPEM is necessarily complex, the basic concept is straightforward. The methodology involves several stages of calculations for each proposed control measure[1]. The steps are:

Step 1. Emissions: We estimate how much a given control measure would reduce (or increase) emissions of each of the pollutants.

Step 2. Concentrations: We estimate how a change in emissions of each pollutant would affect its ambient concentrations and other pollutants related to it. For ozone, PM, and air toxics, we employ photochemical modeling results to calculate pollutant response at the level of each 4 km by 4 km grid square. (Section 2)

Step 3. Population Exposure: We estimate how a change in ambient concentrations would affect the exposure of Bay Area residents to each pollutant, again at the grid square level. (Section 3)

Step 4. Health Impacts: We estimate how a reduction in population exposure would impact various health endpoints, projecting changes in the incidence of endpoints such as asthma emergency room visits, lower respiratory symptoms, and deaths (premature mortality). (Section 4)

Step 5. Health/Social Benefits: We monetize the benefits (i.e. avoided costs) of each control measure by estimating the cost of the health and climate impacts from each pollutant. For each health endpoint, the change in the number of incidents is multiplied by an estimate of the per-incident social cost. For greenhouse gases (GHGs), the change in tons of GHG emissions is multiplied by the estimated social cost per ton of GHGs, expressed in terms of CO_2-equivalent. (Section 5)

The output of the MPEM (Steps 1-5) is an estimated dollar value of the health and social benefits of each potential control measure, based upon the decrease (or increase) in each pollutant.

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[1] For ozone, PM2.5, and air toxics, we employ Steps 1 through 5. For greenhouse gases, only Steps 1 and 5 are applied. For discussion of how we consider greenhouse gases for purposes of this methodology, see Section 5.3.

Applications

For purposes of the 2016 CAP, District staff has used the multi-pollutant evaluation methodology to estimate the aggregate value of the health and climate protection benefits of each potential control measure. The MPEM can be particularly useful in helping to evaluate potential trade-offs; i.e., a situation where a control measure may reduce one pollutant, but increase a different pollutant. In addition, District staff used the MPEM to:

- Estimate the total cost of health impacts and monetary costs associated with current emission levels and ambient concentrations;
- Estimate the aggregate benefit of the overall emission reductions for the proposed 2016 CAP control strategy as a whole; and
- Backcast to estimate the health impacts and monetary costs associated with emission levels and ambient concentrations in years past.

Probability Analysis

Uncertainty is inherent in the MPEM. We consider the range of the uncertainty by means of a probability analysis which is described in Fairley (2010). The probability analysis estimates the degree of uncertainty in the assumptions and computations related to each step in the method, and then calculates an overall probability distribution for the results of the methodology as applied to each control measure. The probability analysis enables us to determine whether the potential benefits of one control measure differ significantly from another.

2016 Update

The MPEM used for the 2016 CAP has been updated in several respects. One key update is to incorporate new data in Stage 1, where we estimate how pollutant concentrations change as a function of changes in pollutant emissions. This involves using the results of a 3-D gridded photochemical model (See Section 2 for details). For the previous CAP, the photochemical model was run only for certain times of year, requiring an extrapolation to annual average pollutant concentrations. For this CAP, the model was run for a representative set of days during the year, making extrapolation unnecessary.

Otherwise, the data going into the MPEM were updated to the most recent available: 2016 population projections from the California Department of Finance, 2011-2013 hospital admissions data from the California Department of Public Health, 2011-2013 mortality data, inflation-adjusted valuation data, and updated concentration-response data from BenMAP (US EPA 2012).

Conclusion

The multi-pollutant evaluation methodology summarized above, and described in detail in the body of this document, is a tool developed by Air District staff, based on existing data and studies, to analyze control measures on a multi-pollutant basis. The results of the MPEM analysis were one of the factors considered by District staff in developing the control strategy proposed in the 2016 CAP.

The MPEM makes use of the tools and technical data currently *available*. In developing the MPEM, we have tried to identify data gaps and technical gaps that should be addressed to improve this methodology for future planning cycles, as discussed in Section 6.

marginal to jointly-considered effects were 0.85 for ammonia, 0.90 for sulfur gases and 1.03 for sulfate.

2.5.10 Calculation of the change in ammonium sulfate concentrations

The model output is in terms of sulfate, so this value was adjusted to convert from sulfate to ammonium sulfate: (132/96).[10]

So, for given percent reductions in ammonia, Δe_a, and sulfur species, Δe_{ss}, and Δe_{sa}, and we predict a change in ammonium sulfate concentrations in grid square i of:

$$\Delta c_i = c_i*(132/96)*[0.85(dc_i/de_a)\ \Delta e_a + 0.90(dc_i/de_{ss})\ \Delta e_{ss} + 1.03(dc_i/de_{sa})\ \Delta e_{sa}]$$

where c_i is the average sulfate concentration from the base-case model run, and dc_i/de_j is the percent change in concentration in grid square i from a percent change in species j computed from the base case model run and the model run with a 20% marginal reduction in species j.

3. Estimating Population Exposure

3.1 Population and Demographics

The MPEM uses population data in two different ways. One is to compute population-weighted exposures. For this, total population is required on a fine geographic basis. The other use is to compute incidence rates. Many of the health endpoint estimates involve incidence rates for a specific age range, e.g., 5-17 for school absences or $\geq$ 27 for chronic bronchitis. Here county-level data by age group is utilized.

To obtain spatially disaggregated population data, we used Census data from the American Community Survey (ACS) for the most recent period available, 2009-2013 (US Census 2015). We obtained population estimates at the census block group level, and applied each to the grid square containing the block group's population centroid. This population was assumed exposed to the concentration estimated for that grid square. The product of population times Δconcentration was then summed for each county and divided by the county population, yielding a population-weighted Δconcentration. Figure 4 provides an example.

To estimate incidence of health endpoints, we used data from the California Department of Finance. These data are projections based on sophisticated modeling that includes ACS data. These were available by county for 2015 by for each age 0-100. These were aggregated into the age ranges needed to estimate incidence rates for various age groups.

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[10] Sulfate, SO_4 has atomic weight 96. Each sulfate molecule combines with 2 ammonium (NH_4) molecules, for an atomic weight of 96 + 2 x 18 = 132.

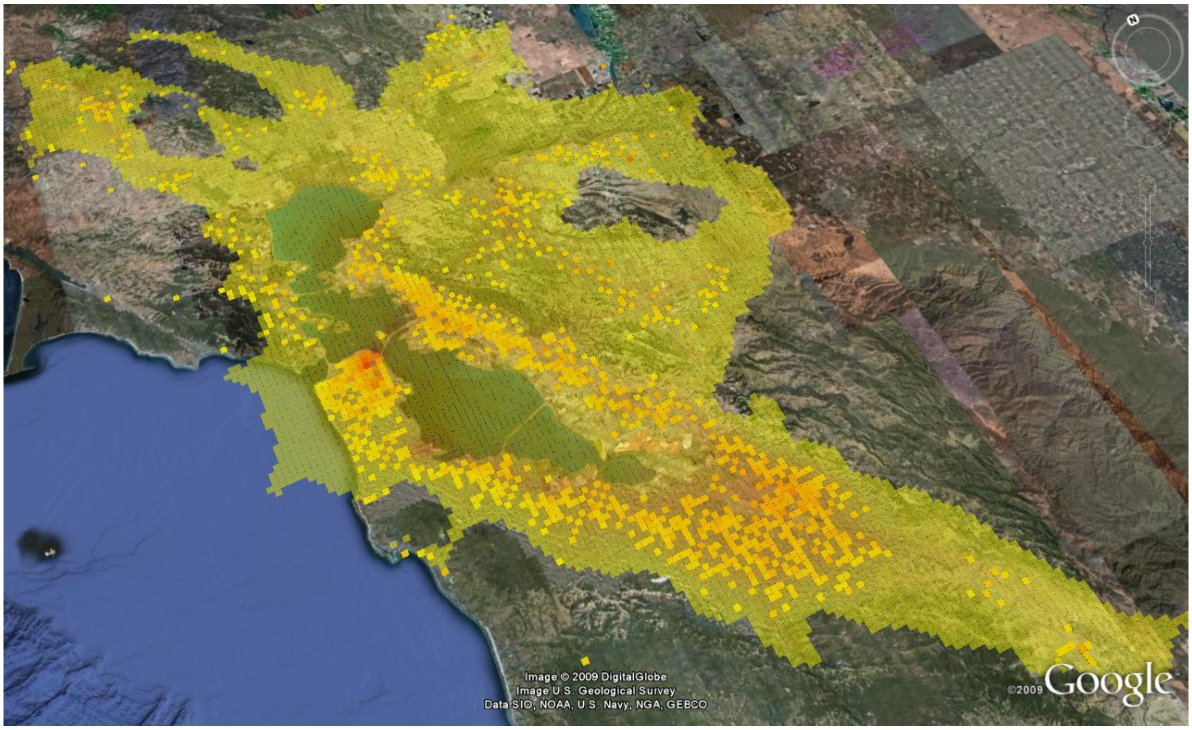

Figure 4. Reduction in benzene concentration overlaid with population. Grid cells with nonzero population shown in solid colors underneath benzene reductions layer.

3.2 Exposure Rationale for Ozone and $PM_{2.5}$

Our method estimates "backyard" exposure, namely assuming that people are at home and outside in their yards all the time (24 hours a day, seven days a week). Although this approach is admittedly simplistic, it is generally consistent with the exposure estimates made in the epidemiological studies that produce the dose-response functions used in MPEM and thus is an appropriate method in combination with steps 4 and 5.

Very few of us spend our entire lives in our backyard. Improvements in estimating real exposures will be of tremendous value, but will require considerable effort to gather data on people's activity patterns and concentrations in various micro-environments. For the current MPEM methodology, however, our simplistic exposure assumptions may be adequate, or even appropriate.

Most of the epidemiological studies used to calculate ozone and $PM_{2.5}$ health effects themselves use only these rough estimates of exposure. Thus, the concentration-response relationships developed are also based on backyard estimates of exposure. In fact, a number of these studies assumed that everyone within a county was exposed to the average monitored value in the county, possibly based on a single monitor. Thus, if anything, our own rough backyard exposure may be a more precise estimate than those used to establish the concentration-response relationships.

What is the effect of this approximation? There are two aspects, both of which suggest that our methods will, if anything, underestimate the pollutant effects on the health effects.

3.2.1 Average ambient concentration

The average ambient concentrations used in the epidemiological studies are not, in general, equal to the average exposure concentration.

For example, suppose average population exposure concentration was 80% of the value measured at monitoring station. Suppose the concentration-response (C-R) slope for, say, hospital admissions, estimated in the epidemiological study were an incidence rate of 0.02 / 10 $\mu g/m^3$ so that there was a 2% change in incidence for a 10 $\mu g/m^3$ change in *monitored* $PM_{2.5}$ concentrations. But actual exposures were not the same, so really, this is a 0.02 change for an 8 $\mu g/m^3$ change in *exposure* concentrations. Thus the C-R slope is 10/8 x (0.002) = 0.0025 per $\mu g/m^3$ in $PM_{2.5}$ exposure.

In the Bay Area, at least, air quality monitors tend to be placed in areas with above-average concentrations. To the extent that this is true in the areas where C-R functions have been calculated, this would cause an underestimation of the response for a given concentration, provided that unbiased estimates of backyard concentrations were used. For $PM_{2.5}$, we used modeled values, which may be unbiased. Thus, for $PM_{2.5}$ C-R functions, the response may be underestimated. For ozone, monitored values were interpolated to backyard values thereby approximately canceling the bias. That is, the backyard ozone values are likely to overestimate actual backyard ozone concentrations, thereby roughly canceling the presumed underestimate in the C-R functions.

It should be noted that if we were able to use the true exposures, the bias would be even stronger because people spend most of their time indoors. The amount of $PM_{2.5}$ that infiltrates is perhaps 70% of the ambient levels (See, e.g., Lurmann & Korc 1994), so this would impart a greater downward bias.

In layman’s terms, the concentration-response function (C-R coefficient) is calculated by analyzing the relationship between known health outcomes for a given population compared with their estimated population exposure. So if population exposure is over-estimated (e.g. by using monitored concentrations that are higher than real exposure), this will result in underestimation of the C-R coefficient. If an under-estimated C-R coefficient is then applied to a more accurate (in this case, lower) population exposure, this will result in underestimation of health effects.

3.2.2 Exposure

Exposures were estimated with error. If exposure were estimated without bias[11], but with error, then the C-R coefficient would tend to underestimate the effect of the pollutant on the health endpoint. This is a regression theory result, where if the independent variable, x, is

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[11] Bias is a systematic over- or under-estimation, like a scale that always reads 3lbs lighter than you really are. Error means the difference between the measured and true value. So a scale might be unbiased but sometimes read up to 2lbs more than the real weight and sometimes down to 2lbs less than the real weight, so the error is plus or minus 2 lbs.

measured with error: $x^* = x + \text{error}$, and the error has zero mean, then the fitted regression slope, b^*, of the regression of y on x^* will tend to be less in magnitude than the true slope, β, from the regression of y on x (had it been known). That is $|b^*| < | \beta |$. See Appendix D.

This issue was considered important by the experts in EPA's elicitation of experts' judgement about the true $PM_{2.5}$ – mortality C-R function:

> "Uncertainties in population exposures assessed using central-site monitoring was raised by all experts as an important issue, and in many cases as a major issue, and nine experts took this issue into account when deriving their median effect estimate of the mortality effects of a 1 μg/m3 change in PM2.5…many thought that this issue caused underestimation of the effects of PM2.5 on mortality. The reason cited for this underestimation was the well-known effect of exposure measurement error ("misclassification") in biasing epidemiological effect estimates towards the null." (page 3-18, EPA 2006a)

Thus, this is a second reason why it's likely that the C-R coefficients from epidemiological studies underestimate the true C-R effect.[12] In our case, it is likely that even with backyard exposures we are estimating the true exposure more precisely than simply using the monitored value. Thus, all else being equal, if the same studies had been done using such backyard exposures instead of monitored values, the slopes would likely have been steeper. In other words, this is a second reason that it is likely that we will underestimate the true effect of the pollutants on health effects.

3.3 Exposures and Cancer

The opposite relation may exist with our estimates of cancer effects, although the exposure bias is dwarfed by other uncertainties. The health impacts from toxic air pollutants are estimated from occupational studies or studies of lab animals. In occupational studies, exposure estimates are often very rough. In studies of lab animals, the exposure may be well-controlled, but the low-dose extrapolation and extrapolation from other species to humans introduce large uncertainties.

In addition to these large uncertainties, there is likely to be a modest overestimate of exposure: We believe our models do a reasonable job of estimating backyard exposure. But indoor exposures are likely to be lower, at least for diesel particulate matter (DPM). The assumed lung cancer risk for DPM is 300 in a million per $\mu g/m^3$ (OEHHA 2016) for an average lifetime exposure of 1 $\mu g/m^3$ (a concentration very near the annual average for the Bay Area). As discussed above, however, most people spend most of their time indoors, say 90%, so, assuming that the PM penetration rate is 70%, then their average exposure would be about $0.1(1) + 0.9(1 \times 0.7) = 0.73\ \mu g/m^3$, for a true risk of $0.73 \times 300 = 219$ in a million.

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[12] The $PM_{2.5}$ – mortality C-R function is an exception because it is based on the pooled judgement of these experts, who took this bias into account in their estimates.

4. Estimating the Impact of Exposure on Health Effects

4.1 Calculation of Health Impacts: C-R Functions

All the health impact calculations have a similar form, a formula that relates a change in exposure concentration to a change in the number of cases of a particular health endpoint such as an emergency room visit, hospital admission, missed school day, or death:

$$\Delta\text{cases} = \text{baseline incidence} \times \Delta\text{risk} \qquad (4.1)$$

where

- Δcases = the annual increase or decrease in the number of cases of that health endpoint in the population resulting from the change in exposure,

- baseline incidence = the underlying rate of that health endpoint, expressed as a number of cases, and

- Δrisk = change in risk of an incidence of that health endpoint resulting from the change in exposure.

The actual function in 4.1 is termed a *concentration-response function* or *C-R function*.

4.2 C-R Functions for Ozone and $PM_{2.5}$

For ozone and $PM_{2.5}$, the C-R functions are generally derived from epidemiological studies that examine the correlation between a health endpoint and exposure to ozone or $PM_{2.5,}$ in conjunction with other potential factors that might affect the endpoint. These additional factors include other pollutants, such as sulfur dioxide, carbon monoxide and nitrogen dioxide, as well as factors such as extreme temperatures, time of year, day of the week, etc. All the C-R functions in this methodology are of two forms, either log-linear or logistic.

Log-linear: The statistical analysis is often equivalent to a regression on the log of the number of incidents. This implies that the regression coefficient for ozone or $PM_{2.5}$, say b, represents a rate. Converting back to the original scale, the estimated change in incidence rate per a change, c, in exposure concentration (to ozone or $PM_{2.5}$) would be $e^{bc} – 1$, where e is the base of the natural log, e = 2.71828 18284 59045 23536….

Thus, to compute the change in the number of cases from a change, c, in concentration, we compute

$$\Delta\text{cases} = \text{baseline incidence} \times (e^{bc} - 1) \qquad (4.2)$$

The baseline incidence might be the number of annual deaths, for example.

Alternatively, we may know the incidence *rate*, the incidence per so many in the population, in which case the formula becomes:

Δcases = population x (baseline incidence rate) x (e^{bc} – 1) (4.3)

Note that the "population" may be some age-subset. For example, if the endpoint is school absences, then the population are those 5-17 years old. A number of the other health effects are based on subsets of the population.

Logistic: This applies to those health studies that used logistic regression in the analysis. The C-R formula is:

Δcases = population x (baseline incidence rate) x (e^{bc} – 1)/(1 + f) (4.4)

where f = e^{bc} x y_0 /(1 – y_0) and y_0 is the baseline incidence rate.

4.3 C-R Functions for Cancer

For cancer from toxics, the C-R function is different. The change in cancer rates is expressed as a risk, b, of an individual getting cancer from a compound from a lifetime (70-year) constant exposure to the compound. Thus the annual number of cases caused/reduced by a given change in average concentration, c, would be:

Δcases = population x b/70 x c formula (4.5)

4.4 Population Data

We use population projections by county.

4.5 Incidence and Incidence Rates

For most health effects we require baseline incidence rates, namely the annual population frequency of a particular health outcome. For this methodology, we were able to obtain some Bay Area county-specific data. Otherwise, we relied on incidence rates from previous health-benefit studies.

For mortality, we used county-by-county annual total non-accidental mortality to county residents, averaging 2011-13, the three most recent years available.

For hospitalization rates and asthma emergency room visits, we obtained 2011-13 county-by-county rates from the California Office of Statewide Planning and Development (OSHPD), using the averages of the three years' data.

Rates for non-fatal myocardial infarctions (MIs) were computed at the national level starting with the National Hospital Discharge Survey for 2010, and adjusting for hospital transfers and miscoding. The number of fatal MIs were multiplied by 1.29 to account for the difference between in-hospital fatality to fatality within 30 days of the event (Coxson 2009). Data were available in 10-year increments. These were multiplied by the appropriate age ranges to get a population incidence rate. Our rates average 2 non-fatal MIs per 1,000, compared with 3 per thousand in BenMAP (Table D-5, US EPA 2012).

For school absence rates, we used a recent San Francisco Unified School District figure of 4.7% per day. (SFUSD 2009)

4.6 Health Effects used in this Methodology

As mentioned in the introduction, a number of health benefit studies have used an approach similar to that used here to investigate the benefits of reducing ozone and $PM_{2.5}$. Among these studies is a near-consensus on which epidemiological studies to use and how to use them. For $PM_{2.5}$, our methodology includes most of those listed in Appendix E of the BENMAP User Manual (US EPA 2012). We also use the BENMAP coefficients, uncertainty estimates, and C-R functions.

4.6.1 $PM_{2.5}$ – Mortality C-R function

The one exception is for mortality, where we use an estimate based on the mean of the median C-R estimates from 12 experts (US EPA 2006a). Specifically, each expert provided a probability distribution that summarized his/her judgement of the magnitude of the $PM_{2.5}$ – mortality C-R effect. Only one, expert K, assumed an effects threshold existed. Several others believed that the C-R effect was somewhat less for lower $PM_{2.5}$ concentrations. To combine these expert probability distributions, we averaged them, using the more conservative (lesser slope) C-R function when an expert provided more than one. We also incorporated the experts' probabilities that the $PM_{2.5}$ – mortality relation was not causal.

The result is a mixture distribution. It has a point mass of 12.5% at zero and a roughly triangular shaped probability density function above that. The median, and also the mode is near a 1% increase in all-cause mortality to persons 30 and older for a 1 $\mu g/m^3$ increase in $PM_{2.5}$. Expert K also placed 100% of the mass of his distribution on values < 0.8% per 1 $\mu g/m^3$. Thus, no matter what probability distribution one uses for this expert, the median of the pooled distribution would not be reduced.

We believe that this C-R coefficient represents a reasonable estimate of the $PM_{2.5}$ – mortality effect. The experts each relied on a range of studies, but they all relied on 2 studies, the Harvard 6-cities study (Dockery *et al.* 1993, reanalyzed in Krewski et al. 2000) and the American Cancer Society study (Pope et al. 2002). The C-R functions from these two studies bracket 1% / 1$\mu g/m^3$. Although the ACS study is based on a huge sample – with participants in the hundreds of thousands – it has limitations. Its participants were self-selected with characteristics that differ systematically from the adult population in general. Another limitation is the error in population exposure estimates, where centrally monitored $PM_{2.5}$ is used as a surrogate. As discussed in section 3.2, this may well lead to a downward bias in the C-R function.

4.6.2 Other C-R functions

For ozone, we use the effects, C-R functions, coefficients and uncertainties from Ostro *et al.* 2006. For ozone and school absences, we used the same study, Gilliland *et al.* (2001), but analyzed it somewhat differently. See Appendix E.

For toxics, we use the unit risk values from OEHHA (2016). We note that these factors are the 95th percentiles of risk, so that the risks, estimated cancer cases and economic values are likely to be overestimated, perhaps by a factor of 2 (Salmon 2009).

Table 3 lists the health effects along with the C-R functions we adopted, the original studies serving as the basis for the functions, the population subset subject to the health effect, and the incidence rates and sources.

Table 3. Health Endpoint C-R Functions and Incidence

Health Effect	**Original Study(s)**	**Population**	**Beta**	**Formula***	**Incidence**	**Incidence source**
$PM_{2.5}$			**% per 1 μg/m^3**			
Mortality	US EPA 2006a + our own summary	≥ 30	1.0	4.1	all non-accidental deaths by county of residence	California Department of Health Statistics
Chronic Bronchitis Onset	Abbey *et al.* 1995	≥ 27 (w/o bronchitis)	1.32	4.3	0.00378	Abbey *et al.*
COPD Hospital Admissions	Ito 2003 & Moolgavkar 2003	≥ 65	.116(.206) Ito 0.185 (.052) Moolgavkar	4.2	county-specific rates, 2011-13 Bay Area rate 0.0009	OSHPD**
COPD Hospital Admissions	Moolgavkar 2003	18-64	0.218	4.2	county-specific rates, 2011-13Bay Area rate 0.0061	OSHPD**
Pneumonia Hospital Admissions	Ito 2003	≥ 65	0.398	4.2	county-specific rates, 2011-13 Bay Area rate 0.0073	OSHPD**
Cardiovascular Hospital Admissions (less MI)	Moolgavkar 2003	≥ 65	0.158	4.2	county-specific rates, 2011-13 Bay Area rate 0.0282	OSHPD**
Cardiovascular Hospital Admissions (less MI)	Moolgavkar 2003	18-64	0.140	4.2	county-specific rates, 2011-13 Bay Area rate 0.0032	OSHPD**
Non-Fatal Heart Attacks	Peters *et al.* 2001	≥ 18	2.41	4.3	based on national data, 2010. The Bay Area average rate is 0.0021	NHDS public use data files, adjusted for 30 day survival.
Asthma Emergency Room Visits	Norris *et al.* 1999	< 18	1.653	4.2	county-specific rates, 2007 Bay Area rate 0.0056	OSHPD**
Acute Bronchitis Episodes	Dockery *et al.* 1996	5-17	2.721	4.3	0.043 cases per child per year	American Lung Association 2002
Upper Respiratory Symptom Days	Pope *et al.* 1991	Asthmatic children 5-17	0.36	4.3	124.8	California Center for Health Statistics reported that in 2003, 14.8% of children and adolescents in California had been diagnosed with asthma

Lower Respiratory Symptom Days	Schwartz & Neas 2000	7-17	0.6	4.3	0.438	Schwartz *et al.* (1994,Table 2)
Work Loss Days	Ostro 1987	18-64	0.46	4.2	2.17	Adams *et al.* 1999
Minor Restricted Activity Days	Ostro & Rothschild 1989	≥ 18	0.741	4.2	7.8	Ostro & Rothschild 1989
Ozone			**% per ppb 1-hr max ozone**			
Mortality	Ostro 2006	All ages	0.04	4.2	all non-accidental deaths by zip of residence	California Department of Health Statistics
Hospital Admissions for Respiratory Diseases	Thurston & Ito 1999	All ages	0.16	4.2	county-specific rates, 2007 Bay Area rate 0.0025	OSHPD**
Asthma Emergency Room Visits	Ostro 2006	< 18	0.24	4.2	county-specific rates, 2007 Bay Area rate 0.0056	OSHPD**
School Loss Days	Gilliland *et al.* 2001	5-17	1.98	4.2	SFUSD rates	SFUSD 2009
Minor Restricted Activity Days	Ostro & Rothschild 1989	≥ 18	0.22	4.2	7.8	Ostro & Rothschild 1989
Toxics			**lifetime risk / μg/m^3**			
Lung Cancer (DPM)	OEHHA 2005	all ages	.0003	4.4	NA	NA
Leukemia (1,3-butadiene)	OEHHA 2005	all ages	.00017	4.4	NA	NA
Leukemia (benzene)	OEHHA 2005	all ages	.000029	4.4	NA	NA
Cancer – various sites (acetaldehyde)	OEHHA 2005	all ages	.0000027	4.4	NA	NA
Cancer – various sites (formaldehyde)	OEHHA 2005	all ages	.000006	4.4	NA	NA

* See formulas in text above.

** OSHPD = California Office of Statewide Health Planning and Development.

4.7 Calculation of Change in Incidence

Estimates of the changes in incidence of various health effects are made for each grid square, using grid square population and county- or Bay Area-level incidence rates, then summed to get county and Bay Area totals. For example, consider asthma emergency room visits. Suppose a control measure would reduce directly-emitted $PM_{2.5}$. We apply the results of Table 3 and Section 2 as follows. For a given grid square, i, the change in $PM_{2.5}$ concentration, Δc_i, is computed. This is combined with the effect coefficient, 0.0165 to compute the exponential part of formula 4.3, The incidence rates differ by county; for Alameda grid squares for example, the incidence rate is 0.0067. So for an Alameda grid square, we would combine this with the estimated 0-17 year-old population, p_i, to produce

$$p_i * 0.0067 * (e^{0.0165*\Delta ci} - 1)$$

that is, the estimated reduction in the annual number of asthma emergency room visits among 0-17 year-olds with residences within grid square i. These values are then summed by county.

There were several variations on this approach, depending on health endpoint.

4.7.1 School absences.

We follow the approach in Hall (2008) to take into account summer vacations, weekends, holidays, etc. See Appendix E for details.

5. Valuation of Health Effects and Greenhouse Gas Reductions

The last step in the methodology is to estimate the economic value of pollution reductions in terms of decreased health and social costs. The goal is to establish whenever possible not just the direct costs of illness, such as hospitalization and medications, but the value placed by individuals on avoiding the illness. This incorporates concerns such as:

- Loss of productive time (work and school)
- Direct medical costs that result from avoiding or responding to adverse health effects
- The pain, inconvenience and anxiety that result from adverse effects, or efforts to avoid or treat these effects
- Loss of enjoyment and leisure time
- Adverse effects on others (family, friends, caregivers, etc.) resulting from their own adverse health effects (Hall 2008).

The following section, 5.1, discusses the methods applied to value the social benefits of air pollution reduction. It is quoted directly from an excellent discussion in Hall 2008.

A CBE Technical Report
2 December 2016

Combustion Emissions from Refining Lower Quality Oil

Part 2: How Much Could a Switch to 'Tar Sands' Oil Increase Direct Emissions of $PM_{2.5}$ and CO_2 from Northern California Refineries?

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CONTENTS

Abstract

Emissions from refining lower quality oil were estimated in the San Francisco Bay Area, where the second largest refining center in western North America is replacing declining current oil supplies with oil imports, and refinery emission limits are now proposed. Data for refinery crude feed, processing, yield, fuels, crude availability and cost, infrastructure plans and projects, and emissions were analyzed to identify a range of plausible worst-case refinery crude feed, energy consumption, and emissions scenarios. The quality of the regional crude feed could worsen from 2020–2050 as 50–80 percent of it is replaced with blends of heavy oil and bitumen. A peer reviewed method that predicted oil quality effects on Bay Area refining energy and emission intensities within 5 percent of those observed during 2008 and 2014 estimated emissions in these "tar sands" oil scenarios. Estimated refinery CO_2 and $PM_{2.5}$ emission intensities increased by ≈39–100 percent in these scenarios, increasing regional mass emissions from refineries by ≈5.9–16 million metric tons per year of CO_2 and ≈390–990 metric tons per year of $PM_{2.5}$.

Introduction

The San Francisco Bay Area hosts the second largest oil refining center in western North America after Los Angeles.[1] Chevron, Phillips 66, Shell, Tesoro, and Valero currently operate the five major refineries here. Collectively, Bay Area refiners produce gasoline and diesel in excess of northern California demand, dominate statewide exports of these fuels even after supplying some of the demand in southern California and other western states,[2] and emit more fine particulate matter and greenhouse gases than any other industrial sector in the Bay Area.[3]

Processing lower quality crude oil is known to increase refinery pollution rates,[4–22] and Bay Area refiners are known to be switching crude feeds as their current crude supply sources in California and Alaska decline.[26–29] Analysis of resource availability and climate constraints indicates that it is feasible, and more economic for society, to avoid low quality, high-emitting oils.[30] However, crude can account for up to 90 percent of a refiner's operating costs,[7] price discounts on low quality oils can exceed 18 percent,[31–34] and Bay Area refiners have announced plans to refine low quality oil[35–44] and have proposed infrastructure projects that could enable those plans.[45–59]

On 14 October 2016 the Bay Area Air Quality Management District (BAAQMD) proposed new Rule 12-16 and requested public comment on the scope of environmental review for this proposal. Proposed Rule 12-16 would establish limits on facility-level emissions of particulate matter air pollution ($PM_{2.5}$, PM_{10}, NO_x, and SO_2) and greenhouse gases (CO_2e) from oil refining in the Bay Area, set at levels that would prevent any significant increase in current annual emissions of these air pollutants.

A complete and accurate environmental review of this proposal to prevent increases in these emissions must, among other things, describe the potential increases in these emissions that the proposal, if implemented, would prevent. Thus, questions regarding whether potential crude feed quality-driven increases in these emissions can be estimated based on currently available information, and how much these emissions could increase in the plausible worst-case scenario, fall within the scope of this environmental review. This report addresses these questions.

Summary of Site-specific Oil Feed Quality Impacts Observed

Impacts of crude feed switching on Bay Area refinery feedstock contamination and pollution rates have been observed many times over more than twenty years.

In 1994 CBE showed that increased selenium (Se) discharges into the San Francisco Bay-Delta estuary were linked to denser, higher-selenium crude feeds.[4] In perhaps the first documented case of Bay Area refinery pollution violations linked to lower quality oil, Se discharges from the Rodeo, Martinez, and Benicia refineries exceeded their discharge limits. Se was concentrated in denser components of their crude feeds, released into the sour gas and sour water streams from coking and hydroprocessing, and passed through partial waste water treatment to discharge, on a mass per barrel refined basis, at rates reaching ten times those of other plants running lower-Se crude feeds.[4] When differences in waste water treatment were accounted for, the Se content of Bay Area refinery crude feeds predicted the refiners' Se/barrel discharge rates almost perfectly (R^2, 0.99).[4]

In 1999 a switch to lower quality, denser crude was a contributing factor in a catastrophic fire during crude unit maintenance work that killed workers and caused a massive air pollution plume at the Avon refinery near Martinez.[5] A U.S. Chemical Safety Board investigation of the incident found that the denser crude overwhelmed a crude desalting unit, resulting in corrosion product plugging of a crude unit pipe downstream which was undetected until the plug released during maintenance, fueling the catastrophic fire.[5]

In the mid-1990s Chevron expanded the capacity of the fluid catalytic cracking (FCC) unit at its Richmond refinery, increasing the refinery's capacity to process separately delivered heavy gas oil as a larger portion of its total oil feedstock. In 2011 the refiner used this capacity to process a total oil feed that, although lower in total crude-plus-gas oil volume, was proportionately higher in heavy gas oil than it processed in 2008.[6] Making gasoline and other engine fuels from heavy gas oil, the densest and most contaminated fraction of whole crude that distills in atmospheric and vacuum crude distillation, requires more energy-intensive carbon rejection and hydrogen addition processing than making the fuels from lighter crude fractions. Thus, refining proportionately more heavy gas oil would have increased the Richmond refinery's energy intensity, and consequently its CO_2 emission intensity, in 2011 as compared with 2008.[6] Reported data confirmed this expected emission intensity effect. The refiner's emission intensity (kg CO_2e/m^3 oil processed) increased in 2011, as compared with 2008.[6]

On 15 January 2007 a major fire in the Chevron Richmond refinery crude unit caused an air pollution plume over parts of Richmond and Marin County. Sulfidic corrosion, a damage mechanism in steel equipment that processes sulfur-containing oils at high temperatures, led to the crude unit pipe failure in this incident.[7] A subsequent incident investigation found that a switch to higher-sulfur crude, which had accelerated sulfidic corrosion,[7] was a contributing factor in the refiner's corrosion-incident emissions.

An April 2007 analysis of the causes of flare emissions at Bay Area refineries showed that refining denser and higher-sulfur crude feeds contributed to recurrent flare emission incidents caused by conversion-product gas imbalances at the refineries.[8]

In 2008 the Western States Petroleum Association (WSPA) reported that the total crude feed for Bay Area refineries contained an average mercury (Hg) content of $\approx$ 5.07 μg/kg.[9] This analysis was required by the Regional Water Quality Control Board after a U.S. EPA study[10] noted that exceptionally high-Hg crude streams from one source area supplying Bay Area refineries could be expected to result in elevated Hg emissions from refineries processing those streams. The WSPA report did not fully account for the disposition and fate of the Hg in these oils, however, it did show an impact. As compared with the weighted average Hg content of the nationwide refinery crude feed (2.9–4.1 μg/kg),[10] the higher Hg content WSPA reported (5.07 μg/kg)[9] documented elevated mercury levels in Bay Area refinery crude feeds.

In 2009–2010 the Phillips 66 San Francisco Refinery commissioned a new heavy gas oil hydrocracker and, with Air Liquide, a new fossil fuel fed hydrogen steam reforming plant that replaced a smaller hydrogen plant the refiner decommissioned at its Rodeo facility. The new hydrocracker increased the refiner's capacity to process lower quality, denser oil and the expanded steam reforming, an energy-intensive process that produces more CO_2 than hydrogen by mass, enabled that added hydrocracking by supplying more hydrogen. The use of this new infrastructure for refining lower quality oil increased the refiner's total CO_2e emissions substantially from pre-project (2008–2009) levels.[6]

In August 2012 twenty refinery workers narrowly escaped death and some 15,000 people sought emergency medical attention for pollution-related symptoms after a catastrophic pipe failure in the Chevron Richmond refinery crude unit spewed hot hydrocarbons that ignited in a major fire and air pollution incident.[7] Sulfidic corrosion that was accelerated by a switch to higher sulfur crude led to the catastrophic pipe failure. In the years before this incident Chevron switched the refinery's crude feed sources dramatically, from approximately 88% Alaskan North Slope (ANS) crude in 1998 to ≈ 62 % imported crude oils that were higher in sulfur than ANS by 2003 and ≈ 77 % imported crude by 2008.[1, 15] The U.S. Chemical Safety Board's investigation found that this switch to higher sulfur, more corrosive crude was a contributing factor in the 6 August 2012 incident.[7]

From 1990–2014 Bay Area refiners built at least 40 million barrels per year of new heavy oil cracking capacity (coking, FCC, and hydrocracking) and, based on the best available estimates by the BAAQMD and California Air Resources Board for this period, their total CO_2e emissions increased by ≈ 3.4 million metric tons per year.[6] This emissions increment from 1990–2014 is linked to that long lasting, higher-emitting infrastructure for refining lower quality oil.[6]

Recently released data from 2014 further confirm a previously reported finding based on data from 2008: a denser crude feed that requires more processing energy than the U.S. average has driven the total greenhouse gas emission intensity of Bay Area refineries higher than the U.S. refinery average. First reported in 2010 based on direct observations,[11] this finding is supported by additional peer-reviewed work[12, 18–22] reported from 2010–2015, and is now further supported by recently reported data from northern California refining industry operations during 2014.[13–17]

Past Estimates of Oil Feed Quality Effects on Refining Energy

Crude oils are complex and widely ranging mixtures of hydrocarbons and contaminants. Crude has larger multi-carbon hydrocarbons, higher carbon and contaminant content, and lower hydrogen content than the major products refiners make from crude, the engine fuels gasoline, diesel, and kerosene jet fuel. These same bulk characteristics make crude oils denser and hydrogen-poor compared with the engine fuels made from them. The differences can be substantial when the wide range of crude oils is taken into account. For example, the average annual crude feeds processed in major U.S. refining centers and California range in density from ≈ 858–902 kg/m^3 as compared with densities of ≈ 737, 814, and 845 kg/m^3 for gasoline, kerosene, and diesel, respectively.[11, 12]

Making engine fuels from crude oils thus requires breaking the larger hydrocarbons in crude into smaller, fuel-sized compounds (cracking), adding H_2 to these hydrogen-poor cracked hydrocarbons, rearranging their chemical structures, and removing their contaminants to protect refinery process catalysts and meet product specifications.[11] Major processes that work harder and process more of the barrel when refining lower quality oil include coking, catalytic cracking, heavy oil hydroprocessing, hydrogen steam reforming of fossil fuels to produce hydrogen needed for that hydroprocessing, and vacuum (heavy oil) distillation.[11, 12, 18–22] These processes use extreme heat, pressure, and chemical energy—notably hydrocarbon feedstock energy conversion to hydrogen and CO_2 in steam reforming, and chemical catalysts that are reactivated by combustion—and are major energy consumers in refineries.[11, 18–21] Consequently, refining lower quality oil increases the processing, energy, and emission intensity of oil refining.

By 2010 peer reviewed research had described the crude feed quality-driven changes in refinery energy intensity quantitatively and showed crude feed quality can predict average multi-plant refinery energy and emission intensity based on real-world U.S. oil refining data.[11] This research[11] compared refinery crude feed, processing, yield, and fuel data from four regions accounting for 97% of U.S. refining capacity during 1999–2008 among regions and years for effects on processing and energy consumption predicted by the processing characteristics of denser, higher sulfur oils. Crude feed density and sulfur content could predict 94% of processing intensity, 90% of energy intensity, and 85% of CO_2 emission intensity differences among regions and years and drove a 39% increase in emissions across regions and years. Fuel energy for processing increased by ≈ 61 MJ/m^3 crude feed for each 1 kg/m^3 sulfur and 44 MJ/m^3 for each 1 kg/m^3 density of crude refined. Differences in refinery products, capacity utilized, and fuels burned were not confounding factors. Fuel energy increments observed predicted that a global switch to “tar sands” oils, should that occur, could double or triple refinery emissions of carbon dioxide from fuel consumption to process the oil.[11]

By 2015 several other independent research efforts quantified oil quality effects on refinery energy intensity using either observed data,[12] or more detailed process-specific modeling based on engineering assumptions and additional details of plausible crude feeds.[18–21] These efforts further supported the effect of oil quality on refinery energy intensity the previous work documented based on U.S. refinery observations,[11] reporting energy and emission intensity effects of similar scale for comparable oil quality, process configuration, and product slate assumptions. Some of these more detailed methods[20–21] may yield more accurate estimates of oil quality-driven energy and emission impacts than the 2010 method,[11] especially for estimating impacts at individual refineries—so long as data those methods require are reported publicly. Cautions against estimating energy and emissions at individual refineries based on oil density and sulfur content alone without considering more detailed plant-specific data appeared in all of this work, and some of it illustrated these plant-level limitations quantitatively.[11–12, 18–21] However, data required for the more detailed methods—such as crude feed hydrogen content, the volume and quality characteristics of specific crude feed distillation fractions, process-level inputs and outputs, and plant-specific product slates—are not yet publicly reported and available for Bay Area refineries.

In 2015 research that assumed up to half of the U.S. crude feed could be replaced by diluted bitumen oils from Canada with only minimal refinery equipment changes found increased petroleum coke combustion could increase $PM_{2.5}$ emissions from FCC units by up to 25 %.[22] These assumptions may not apply to the Bay Area industry—which gets undiluted heavy oils from sources worldwide[15] and has launched major infrastructure projects.[6, 35–39] Also, this research did not estimate refinery-level impacts, and as it notes,[22] it did not estimate SO_2 or $PM_{2.5}$ emissions from refinery-wide burning of the highly contaminated gases that severe coking of bitumen-derived oils can exacerbate.

A 2012 study sponsored by Chevron[23] reported oil quality-driven increases in refinery energy and emissions based on unverifiable estimates that fell below those reported by other work.[11–21] This study[23] assumed a better quality worst-case crude feed than those observed, relied on undisclosed processing assumptions that could not be verified, reported worst-case energy and emission increments smaller than those observed, and made substantial errors in its comparisons with other work.[24–25] For these reasons this study[23] is noted for completeness but is not used in the analysis herein.

Importantly, the estimation method reported in 2010 was shown to predict the average energy intensity (*EI*) of California and Bay Area refineries well. This method[11] uses observed data from U.S. refining regions[†] to estimate refining *EI* based on a given refining region's observed crude feed density, crude feed sulfur content, product slate, and operable crude capacity utilization.[††] It predicted average California refinery *EI* during 2004–2009 within 1 % (5.27 GJ/m^3 predicted *v.* 5.32 GJ/m^3 observed).[12] Further, it predicted the average Bay Area refining *EI* in 2008—which was observed from actual

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[†] Observed data inputs include energy intensity *(EI)*, the total refinery process energy consumed per volume of crude feed, based on reported fuels consumed in GJ/m^3 crude refined; crude feed density *(d)* in kg/m^3 crude refined; crude feed sulfur content *(S)* in kg/m^3 crude; the utilization of operable atmospheric distillation capacity *(CapUt)* in percent; refined products ratio *(Pratio)*, the volume of gasoline, kerosene, distillate, and naphtha divided by that of other refinery products.[11]

[††] Statewide during 2004–2009 all of these data (*d, S, CapUt, Pratio*) were observed actuals; for northern Calif. refineries these data were either observed actuals (2008: *d, S;* 2014: *d, S, CapUt*) or West Coast (2008: *CapUt, Pratio*) or statewide (2014: *Pratio*) observed actual data "defaults."

reported Bay Area refining CO_2 emissions of 360 kg CO_2e per m^3 crude and the 68.4 kg CO_2 per GJ emission intensity of the West Coast refinery fuel mix that year—within 1 % (5.31 GJ/m^3 predicted *v.* 5.26 GJ/m^3 observed).[11] In 2011 analysis using more complete Bay Area crude feed and California refinery process fuels and product slate data also showed that this method predicted Bay Area refinery *EI* during 2008 within 1 % of observed statewide *EI* that year.[12]

Data that became available by the summer of 2016[12–17] allow for an additional test of the estimation method reported in 2010[11] for estimating changes in the energy intensity of Bay Area refining based on changes in crude feed quality. These northern California-specific refining industry data are summarized in Table 1.

As shown in Table 1, the energy intensity (*EI*) of Bay Area refining that is predicted by the estimation method reported in 2010[11] based on reported average Bay Area refinery crude feed quality in 2014 is within 2 % of that actually observed from reported refinery emissions in 2014 and average refinery fuels consumed. Moreover, when the relationship of refinery feedstock to refinery products is considered, the sensitivity analysis summarized in the table shows that the method predicts refinery energy intensity well despite residual uncertainty about refinery product slates.

The “sensitivity cases” analyzed assume a ratio of gasoline, diesel, kerosene and naphtha to other refined products (products ratio) that is either 20 % lower or 20 % higher than the average observed statewide from 2004–2009 (the “SC–20%” and “SC+20%” cases in Table 1). This is a very conservative assumption, especially for the –20% case, because the statewide crude feed from 2004–2009 was denser than the Bay Area crude feed in 2014,[12, 14–15] and energy-intensive refining increases the portion of denser crude that is converted to gaseous and solid byproducts instead of engine fuels. Nationwide data show that refinery products ratios tend to decrease with increasing crude feed density and refinery energy intensity, and refinery yield tends to shift, from gasoline and diesel to coke and fuel gas, as crude feed quality worsens and refinery *EI* increases.[11] Indeed, the inverse relationship between products ratio and *EI* (which is weak) is explained in large part by the difficulty of maintaining light liquids yield from much denser crude. Thus, if the Bay Area products ratio in 2014 differed from that observed during statewide refining of relatively denser crude, it most likely was closer to the “SC+20%” case (prediction within 1 % of observation). Moreover, in all cases predicted *EI* is within 5 % of that observed. Therefore, these data indicate the method predicts Bay Area refinery *EI* well.

Table 1. Observed and predicted northern California refining data, 2014.

–––––––Data inputs analyzed to estimate (predict) refinery energy intensity–––––––

Crude feed quality		Capacity utilization	Products ratio (Pratio)
Density *(d)*	Sulfur content *(S)*		
891.71 kg/m^3	11.70 kg/m^3	97.7 %	3.871
Based on 55% foreign, 34.7% Californian, and 10.3% ANS (<1% other) N. Calif. crude feed in 2014;[14] and respective foreign,[15] Calif.,[12] ANS[12] crude densities of 869.66, 932.70, 871.40 kg/m^3 and sulfur contents 14.39, 8.03, 9.67 kg/m^3.		From 2014 N. Calif. crude feed and capacity[13, 16] of 46.48 and 47.58 MM m^3.	Ratio of gasoline, diesel, kerosene, naphtha to other products; Calif. avg. from 2004–2009.[12]
Sensitivity case (SC) inputs for possible variability in N. Calif. refinery products ratio (+/– 20 %):		SC – 20 %	3.097
		SC + 20 %	4.645

–––––––Actual (observed) and estimated (predicted) refinery energy intensity–––––––

Observed energy intensity (*EI*)	Predicted energy intensity (*EI*)		
(GJ/m^3)		(GJ/m^3)	(Δ from observed)
4.874	Prediction	4.950	+ 1.56 %
	SC – 20 %	5.073	+ 4.08 %
	SC + 20%	4.827	– 0.96 %
From reported emissions of 347.3 kg/m^3 crude run by N. Calif. refineries in 2014,[13, 17] and Calif. average refinery fuel mix emission intensity during 2004–2009 (71.25 kg/GJ).[12]	Estimated from data inputs above in the prediction mode of the 2010 method.[11] SC +20% and –20% data: sensitivity analysis cases above. See Appendix A for details.		

Data from California Energy Commission,[13–14] U.S. Energy Information Administration,[15–16] Union of Concerned Scientists,[12] and California Air Resources Board.[17] Predictions by 2010 estimation method.[11] *See* end notes for full references. Data shown include the Nipomo facility of the San Francisco refinery.

Potential Changes in Bay Area Refinery Crude Feed Quality

A major change in Bay Area and California refinery crude feeds is underway and nearly certain to continue. During 1985–1988 California refiners received 95 % of their crude feed from California and Alaska.[26] Then total combined crude production in these states fell by 65 % from 1988–2014.[27–28] By 2014 these states accounted for only 48 % of statewide[26] and 45 % of Bay Area[14] crude feed. Government[29] and industry[36] analyses confidently predict that the geologic and market factors driving this terminal decline in West Coast oil resources and their replacement with new oil resources will keep driving California crude-feed switching. Further, reliance on these dwindling supplies for 45 % of its current feed shows Bay Area refining will continue to be affected by these factors.

Meanwhile, key differences in the delivery infrastructure for crude acquisition by Bay Area refiners also increase the likelihood of future crude switching here. California crude supplies are delivered to the Bay Area for refining via pipelines.[14] In contrast, the imported foreign oils that comprise 55 % of Bay Area refiners' current crude feed is delivered to them via marine vessels sailing from oil ports worldwide and, to a much lesser but potentially growing extent, via oil trains from the Canadian tar sands.[14] Thus, instead of being "hardwired" into specific crude fields connected to them by pipelines, Bay Area refiners are increasingly able to switch a major and growing portion of their crude feed by choosing among a wide variety of imported oils.

Their wide variety of choices for replacement crude allows Bay Area refiners to acquire, blend, and process future crude feeds that could be of better, similar, or lower quality than those they process now. Indeed, climate constraints—which limit the amounts of fossil fuels than can be burned without risking severe and irreversible societal and economic impacts—suggest that some 40 % of currently proven oil reserves cannot be used,[30] so there is no valid societal reason for using the dirtier-burning portion of the oil resource. In fact, from a societal standpoint, using much more of the so-called "extreme" oils such as tar sands oils does not make economic sense.[30]

However, crude acquisition can account for up to 90 % of refinery operating costs,[7] and price discounts on low quality oil can be substantial. On a barrel-for-barrel basis, from 2004–2015, annual discounts on denser crude (≤ 20 °API *v.* 35.1–40 °API) ranged from 8–28 % of West Coast refiners' crude acquisition costs, and discounts on Canadian Bow River Heavy versus Saudi Arabian Medium *averaged* 18.9 % of West Coast refiners' crude costs.[31–34] Refiners that are able to run bottom-of-the-barrel crude and externalize the associated pollution costs could boost profits on such cost savings. As of 2014 such low-quality (≤ 20 ° API) crude oils accounted for only about 3 % of Bay Area refinery crude imports,[15] however, both globally and regionally, the oil industry has announced plans to refine low quality oil here in much greater volume.

Crude Switch Plans

In 2007 a report in the *Oil & Gas Journal* described industry plans to expand the market for price-discounted oil produced in the Canadian tar sands by, among other things, sending large amounts of it to California refineries as a new potential growth market.[35] By 2009 a paper published by the Society of Petroleum Engineers explained this from a refiner's standpoint, concluding that the Canadian tar sands is "the most promising source for California refineries" to replace dwindling current crude supplies in the long term.[36]

A 2013 Alberta Energy Resources Conservation Board report described projects to send tar sands oil to California if the state's standards allow the resultant emissions, suggesting "90 percent of its refinery capacity" might be "able to process heavier crudes."[37] The same year Valero reported to investors on its "strategy" to refine "cost-advantaged crude oil" and its plan to bring that oil to its Benicia refinery by train.[38] Valero's 2013 report includes a chart showing that Western Canadian Select, a tar sands-derived crude stream, is the most price-discounted crude oil targeted, costing much less than fracked shale oil from the Bakken formations to the south of the Canadian tar sands in the U.S.[38]

A 2013 report to investors by Phillips 66 stated its plans for "moving Canadian crudes down into California … refineries."[39] A 2014 report to investors by Phillips 66 stated its plans to bring this "advantaged crude into California" by train and ship via Ferndale, WA and by train to the Nipomo facility of its San Francisco Refinery (SFR).[40] That project that would bring tar sands oil through the Bay Area via rail for refining at the SFR's Nipomo and Rodeo facilities. A map posted on a Phillips 66 website in 2015 showed crude oil delivery arrows pointing from the Canadian tar sands region to the SFR.[41]

In 2014 Tesoro reported to investors on its projects to "strengthen refinery conversion capability" for "feedstock flexibility." [42] Tesoro also reported greater future production in the Canadian tar sands than any other "key Tesoro market," and that its rail-to-marine terminal project in Vancouver, Oregon would be "competitive with direct rail cost to California."[42]

In 2015, the Canadian Association of Petroleum Producers (CAPP) reported an update on plans to greatly increase tar sands oil exports to California refineries.[43] This CAPP report updated details of its plans to export increasing production of those bitumen-derived oils to the West Coast, including California, via pipeline, boat, and train.[43]

Also in 2015, a report by CBE and ForestEthics[44] identified oil train projects statewide that, collectively, could replace up to 40–50 % of the current statewide California refinery crude feed via new and expanded rail delivery facilities alone.

Crude Switch Projects

Plans for the oil industry's regional crude switch are being implemented piecemeal through site-specific projects. Proposed by various oil companies to build new or expanded capacity for oil delivery, storage, and processing at existing or proposed facilities, these pieces of the larger regional infrastructure project could collectively enable the regional oil feed switch. Parts of this infrastructure have been implemented despite incomplete safeguards against oil switching impacts.[45] These parts include a Richmond refinery heavy gas oil processing expansion, and much the 40 million barrels/year of new heavy oil cracking capacity Bay Area refiners built since 1990.[6] Other parts of the planned infrastructure have not yet been fully implemented: At least 16 northern California oil infrastructure projects that could enable the industry's plans to refine lower quality oil in the Bay Area have been proposed in recent years.

In 2011 the Chevron Richmond refinery proposed a project to further expand its cracking and hydroprocessing capacity for refining heavy gas oil and greatly expand its hydrogen production capacity.[46] Not yet fully implemented, this project was approved with conditions in 2014[46] after a larger project that could have enabled a full-blown switch to refining lower quality crude and gas oils was blocked by state courts in 2009 and 2010 for failure to disclose and address crude switching impacts.[47]

Although the Richmond refinery has existing capacity to acquire all of its oil feed via tanker and barge, Kinder Morgan proposed an oil train-unloading terminal adjacent to the Richmond refinery in 2013. The Air District approved this project in 2014 without adequate public notice and despite the resultant public health hazards.[48] This project expanded the capacity of Bay Area refineries to process tar sands oils and fracked shale oils delivered by "unit" trains dedicated to oil transport, however, a condition of Chevron's 2014 project approval that was adopted by the City of Richmond prohibits Chevron from processing oil delivered by Kinder Morgan Richmond oil train terminal.[46]

In addition to its 2009–2010 heavy gas oil hydrocracking and hydrogen plant expansion[6] discussed above the Phillips 66 San Francisco Refinery (SFR) proposed at least five other interrelated infrastructure expansions. Since 2012 the company proposed a throughput expansion and oil train unloading spur at the SFR's Nipomo facility, a light ends debottlenecking "LPG project" at its Rodeo facility, and three expansions of wharf capacity enabling increased oil imports at its Rodeo facility.[49-50] The interrelated infrastructure expansions proposed could enable the refinery to switch the vast majority of its crude feed to bitumen-derived and fracked oils.[49-50]

During 2015–2016 NuStar Shore Terminals proposed switching over a major portion of its rail-linked ethanol storage and transfer facility at Rodeo to crude service.[51] This proposed oil storage and transfer project would be linked by pipeline to the adjacent Phillips 66 Rodeo refining facility, and could serve other Bay Area refineries as well. It was proposed after WesPac withdrew a proposal for a massive new rail- ship- and pipeline-linked oil storage and transfer facility in Pittsburg that could have served any or all the Bay Area refineries.[52–53]

The Shell Martinez refinery proposed a crude oil storage and wharf capacity expansion that could enable it to acquire larger amounts of low quality imported oil in 2011[54] and, in 2014, proposed a major refinery reconfiguration project.[55] This project appears, based on preliminary information, to enable refining lighter, better quality crude feeds,[55] but the project and its public review have been delayed since 2014[56] for unknown reasons.

In 2009 Praxair proposed a hydrogen pipeline between the Chevron Richmond, Phillips 66 Rodeo, and Shell Martinez refineries that would have supported expanded refining of lower quality oils by supplying more hydrogen for the processing of denser, hydrogen-poor oils.[57] This project was delayed by the company and Contra Costa County review of it lapsed in 2014. Whether this project will be re-proposed is unknown at this time.

Tesoro has proposed a major wharf expansion that could enable its “Golden Eagle” refinery at Avon (near Martinez) to acquire and process lower quality imported tar sands and fracked shale oils in greater amounts.[58] The approval of environmental review for this project by the State Lands Commission has been challenged is still under review in the state courts as of November 2016.

Valero has proposed an oil train unloading project at its Benicia refinery that would enable the refinery to acquire and process up to 70,000 barrels/day of Canadian tar sands oil, an amount equivalent to 45–50 % of its current crude feed, via the proposed new rail infrastructure alone.[59] This project was rejected by Benicia’s Planning Commission, then City Council, in 2016. Whether Valero will appeal this decision remains unknown.

Many of these projects were undisclosed or obscured at first: this list may be incomplete.

Tar Sands Oil Potential

“Tar sands oil” as this term is used herein includes “heavy oil” and “natural bitumen” as defined by the U.S. Geological Survey (USGS).[60] The USGS reports average densities of 957 and 1,030 kg/m^3 and average sulfur contents of 27.8 and 45.5 kg/m^3 for heavy oil and natural bitumen, respectively.[60] Even the low end of this range is much denser and more contaminated than the average Bay Area refinery crude feed in 2014 (892 kg/m^3 density; 11.7 kg/m^3 sulfur).[12, 14, 15] Each of at least 23 geologic basins in at least 16 countries in north and south America, Africa, and north, central, south and southeast Asia holds at least 14.7 billion barrels of these tar sands oils,[60] which is enough to supply 100% of the current Bay Area crude feed[13] for 50 years or longer.

A chart from a California Energy Commission (CEC) analysis[29] that forecast future California crude feed replacement is reproduced as Chart 1. As the chart illustrates, the CEC has projected that ≈ 83 % of the total California refinery crude feed could be imported by 2030 in its “high case” forecast.[29] Note the CEC’s “imports” definition:

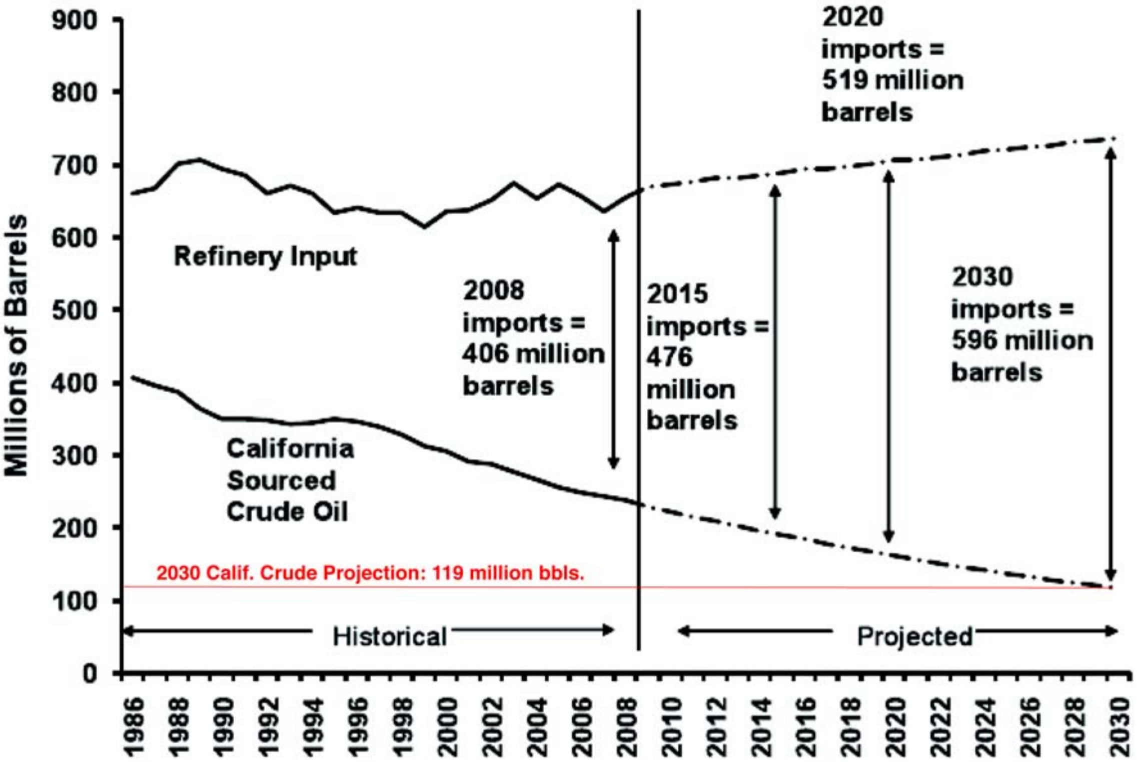

Chart 1. High Case Forecast for California Crude Oil Imports. Excerpted from California Energy Commission Transportation Energy Forecasts and Analysis (Figure 4.8).[29] California sourced oil projection scale in 2030 (red in chart) was added by CBE for reference.

Consistent with refiners' greater flexibility to switch away from current crude sources delivered via boat and train than those delivered via pipeline, this forecast distinguished California-sourced (pipeline) crude from the other sources of crude ("imports") refined. However, the CEC forecast excluded the environmentally relevant, if not crucial, period from 2030–2050, and in addition to continued California supply decline, the CEC "high case" also assumed future refinery production growth that may or may not occur. (*See* Chart 1.) Separating out that latter assumption, the CEC forecast a 3.2 %/year decline in California crude supply based on historic data in its "high case" (shown) and a 2.2 %/year decline in California supply based on recent years' data in its "low case" (not shown).[29]

Based on the 2.2–3.2 %/year decline in California pipeline crude the CEC forecast,[29] and the amount of this pipeline crude in the 2014 Bay Area crude feed (34.7 %),[14] the Bay Area feed could be 29–30 % pipeline crude (70–71 % "imports") by 2020 and 11–16 % pipeline crude (84–89 % "imports") by 2050. Thus, in oil switching scenarios consistent with the industry plans and infrastructure projects documented above,[31–59] tar sands oil could replace 50–80 % of the current Bay Area crude feed during 2020–2050. Table 2 summarizes data and forecasts for Bay Area crude feed quality in these scenarios.

Table 2. Potential Bay Area crude feed quality in tar sands scenarios, 2020–2050.

Low Case				
Oil source (access mode)	Current 2014 (mixed)	Heavy oil (import)	Bitumen (import)	The quality of the total crude feed is calculated as the sum of the oil sources' feed-weighted data:
Source density	891.71 kg/m^3	957.40 kg/m^3	1033.60 kg/m^3	
Source sulfur	11.70 kg/m^3	27.80 kg/m^3	45.50 kg/m^3	
Percentage of feed	50 %	50 %	0 %	
Feed-weighted density	445.86 kg/m^3	478.70 kg/m^3	—	
Feed-weighted sulfur	5.85 kg/m^3	13.90 kg/m^3	—	
		Low Case crude feed density:		**924.56 kg/m^3**
		Low Case crude feed sulfur content:		**19.75 kg/m^3**
High Case				
Oil source (access mode)	Current 2014 (mixed)	Heavy oil (import)	Bitumen (import)	The quality of the total crude feed is calculated as the sum of the oil sources' feed-weighted data:
Source density	891.71 kg/m^3	957.40 kg/m^3	1033.60 kg/m^3	
Source sulfur	11.70 kg/m^3	27.80 kg/m^3	45.50 kg/m^3	
Percentage of feed	20 %	40 %	40 %	
Feed-weighted density	178.34 kg/m^3	382.96 kg/m^3	413.44 kg/m^3	
Feed-weighted sulfur	2.34 kg/m^3	11.12 kg/m^3	18.20 kg/m^3	
		High Case crude feed density:		**974.74 kg/m^3**
		High Case crude feed sulfur content:		**31.66 kg/m^3**

Based on replacement of 50–80% of baseline 2014 crude feed from Table 1[12, 14, 15] by blends of 50–100% heavy oil with bitumen, and average heavy oil and natural bitumen density and sulfur reported by USGS.[60]

Shading in Table 2 denotes the crude feed calculation: In the low case current and heavy oil sources are each 50 % of total feed, so their "feed-weighted" densities are half their actual (source) densities; adding their feed-weighted densities yields crude feed density.

Both the amount of the current crude feed replaced, and the quality of the oil blends replacing it, affect Bay Area crude feed quality. Table 2 illustrates the combined effects: In the low case 50 % of the current crude feed is replaced by blends of heavy oils that are less dense and contaminated on average than bitumen, further limiting the change in feed quality relative to the high case, which includes additional new bitumen imports. In the high case, 80 % of the current crude feed is replaced by blends of 50% heavy oil and 50% bitumen, thus heavy oil and bitumen is each 40 % of the high case crude feed. In these tar sands scenarios the Bay Area refinery crude feed ranges from ≈ 925–975 kg/m^3 in density and ≈ 19.7–31.7 kg/m^3 in sulfur (2.14–3.25 wt. % sulfur) during 2020–2050.

The potential increase in crude feed density is substantial compared with the densities of Bay Area crude feeds processed in 2014 (≈ 892 kg/m^3)[12, 14, 15] and 2008 (≈ 900 kg/m^3),[11] and is extreme compared with the average U.S. crude feed density during 1999–2008 (≈ 873 kg/m^3).[11] However, refining technology that can process such oil blends exists. In fact, the density of the Shell Martinez refinery crude feed in 2008 (≈ 932 kg/m^3)[12] is within the range forecast here (925–975 kg/m^3).

The potential increase in Bay Area crude feed sulfur content also is substantial and on the same scale some refiners have designed for and processed. The sulfur content of the crude feed refined in Minnesota, Wisconsin, and North and South Dakota in April 1992 (3.16 wt. %),[61] and the design crude feed sulfur content of a project proposed but not built at the Chevron Richmond refinery (3.00 wt. %)[47] are within the range of this forecast (2.14–3.25 wt. %).

Accordingly—in addition to the need for crude source replacement, impetus for cheaper crude, its availability, and the industry's plans and projects that could continue to build for the crude switch forecast herein—the knowledge that some plants have processed roughly similar quality oils further supports the crude feed quality scenarios in Table 2.

Emissions Estimate for Bay Area Tar Sands Refining Scenarios

The direct emissions of air pollutants from oil refining that would be limited by proposed Rule 12-16 are causally, strongly, and positively related to refinery energy consumption.[†] Therefore, increases in these emissions that this rule could prevent may be estimated based on the energy consumed to refine potential lower quality 2020–2050 crude feeds.

These estimates used the peer reviewed method reported in 2010[11] because it is supported by nationwide data, estimated the energy intensity (*EI*) of this refining center well, and could predict *EI* based on publicly available, transparently verifiable, data. The formal method description is available free: http://pubs.acs.org/doi/abs/10.1021%2Fes1019965. Scenario-specific data inputs used in this application of the method were as follows.

- The density (*d*) of the potential crude feeds, in kg/m^3 crude, is the first of four data inputs to the prediction mode of the method. *d* is 924.56 kg/m^3 in the low case and 974.74 kg/m^3 in the high case. *See* pp. 14–16 and Table 2.
- The sulfur content (*S*) of the potential crude feeds, in kg/m^3 crude (the second data input): 19.75 kg/m^3 in the low case and 31.66 kg/m^3 in the high case. *Id.*
- Refinery capacity utilization (*CapUt*), the gross input to atmospheric crude distillation units divided by those units' operable capacity, in percent, is the third input: 90.3 % in both scenarios. This is the statewide average from 2004–2009.[12] This multi-year average spans years of high and low California engine fuels demand, and was used to more reliably forecast potential 2020–2050 operating conditions.
- Products ratio (*Pratio*), the volume of gasoline, kerosene, distillate, and naphtha divided by that of other refinery products (the fourth input): 3.871 in both scenarios; the statewide average[12] for the same period and reasons as for *CapUt.*

Descriptive data from refineries nationwide that support the predictions, and detailed results for *EI*, are given in Appendix B. *EI* predicted in the scenarios was compared with *EI* and emissions observed in 2014.[12, 13, 17, 62] 2014 is the most recent year when this method was shown to predict Bay Area *EI*. These comparisons are given in Table 3.

[†] At the points of emission from refineries, the $PM_{2.5}$ precursors NOx and SO_2 are oxidation products of combustion, condensable and filterable PM are combustion products (except for cooling tower PM emissions, which the proposed rule, in any case, would not limit) and CO_2e is ≈ 98.1–99.8% (100-yr GWP)[11] CO_2, a combustion product and, in the case of H_2 plants, emitted by consuming energy to strip H_2 from hydrocarbons in the steam reforming shift reaction.[11]

Table 3. Potential refinery energy and emission intensities of tar sands scenarios.

Results for Energy Intensity (EI)

	EI predicted by crude feed quality[a]			*EI* baseline[b]	Energy ratio (*ER*)
	Prediction (GJ/m^3)	95% confidence (GJ/m^3)	R^2	2014 observed (GJ/m^3)	Scenario : Baseline (ratio)
Low Case	6.802	+/– 0.446	0.90	4.874	1.40
High Case	9.719	+/– 0.654	0.90	4.874	1.99

Results for Emissions

—— Total N. Calif. refining crude feed vol. reported for 2014 (46,479,000 m^3)[c] held constant ——

	Energy Emissions	2014 (*ER* 1.00)[c]		Low Case (*ER* 1.40)		High Case (*ER* 1.99)	
		kg/m^3	tonnes/y	kg/m^3	tonnes/y	kg/m^3	tonnes/y
CO_2e	71.3 kg/GJ	347	16.1 MM	486	22 MM	690	32 MM
$PM_{2.5}$	4.47 kg/TJ	0.022	1,010	0.031	1,400	0.044	2,000
PM_{10}	4.78 kg/TJ	0.023	1,080	0.032	1,500	0.046	2,100
NOx	16.7 kg/TJ	0.081	3,780	0.113	5,300	0.161	7,500
SO_2	9.46 kg/TJ	0.046	2,140	0.064	3,000	0.091	4,200

(a) *EI* of Bay Area refining for crude feeds shown in Table 2 predicted by a peer reviewed method,[11] *see* Appendix B for details. (b) Bay Area refining *EI* observed in 2014 from Table 1. Energy ratios show that potential refinery *EI* is 1.40–1.99 times that observed. (c) Bay Area refining crude feed[13] and emissions[17, 62] observed in 2014. Energy emissions (emissions per unit refinery energy consumed) are based on observed *EI*, crude feed volume, and emissions in 2014. Potential (low and high case) emissions per m^3 crude refined are estimated from observed 2014 emissions per m^3 crude refined and *ER* data; potential mass emissions are estimated from these kg/m^3 emissions and crude feed volume.

As stated, the range of potential worst-case 2020–2050 Bay Area tar sands scenarios is bounded by a "low case" (50 % more heavy oil; 925 kg/m^3 *d*, 19.7 kg/m^3 *S* crude feed) and a "high case" (80 % more heavy oil/bitumen; 975 kg/m^3 *d*, 31.7 kg/m^3 *S* crude feed). Review of Table 3 reveals very large energy and emission impacts from refining lower quality oil in these scenarios. Refinery energy intensity predicted by the lower quality crude feed is ≈ 1.40–1.99 times the current level (*see* energy ratio results), and drives production-weighted (kg/m^3 crude) increases of 39–100 % in CO_2e, $PM_{2.5}$, PM_{10}, NOx, and SO_2 emissions from the Bay Area refining industry. *See* kg/m^3 results in Table 3.

Emitting more per barrel to refine low quality oil could greatly increase regional mass emissions. At current feed volume total annual emissions from Bay Area refiners could increase by approximately 5.9–16 million tonnes of CO_2e, 390–990 tonnes of $PM_{2.5}$, 420–1,020 tonnes of PM_{10}, 1,520–3,720 tonnes of NOx, and 860–2,060 tonnes of SO_2. *See* tonnes/year results in Table 3.

Discussion

Abundant evidence documents the need for the crude switch that Bay Area refiners already have begun, their impetus, plans and projects for switching to lower priced, lower quality oils, the ability to estimate energy-related emission impacts of this planned crude switch, and its severe potential impacts. In the plausible worst case, switching 50–80 % of the Bay Area refining industry's crude feed to blends of heavy oil and bitumen could increase the industry's particulate and greenhouse gas air pollution by ≈ 39–100 %.

The method used in this estimate has predicted oil quality-driven energy and emission increments from the Bay Area refining industry within 5 %. The oil quality-driven energy and emission increments that the method predicts in this estimate exceed this +/– 5 % power of prediction for the Bay Area industry by ≈ 6.8–19 times.

Other estimates and observations further support this estimate. In 2015 Gordon et al.[21] estimated CO_2e emissions from refining six crude oil streams (≈ 500–630 kg/m^3) that fall within those estimated here (486–690 kg/m^3). $PM_{2.5}$ emissions from the Chevron Richmond and Shell Martinez refineries in 2014 (0.028–0.046 kg/m^3 as compared with crude capacity)[16, 62] approach or exceed those in this estimate (0.031–0.044 kg/m^3). CO_2e emissions from the Shell Martinez refinery reported for 2008 (≈ 497 kg/m^3)[12] exceed the low case emissions in this estimate (486 kg/m^3). Finally, the tenfold increase in oil quality-driven refinery discharges of selenium reported in 2004[4] far exceeds the doubling of emissions reported for this estimate's high case.

The potential switch to tar sands oil would be incremental. Much of the infrastructure that would enable the switch to 50 % heavy oil in the low case has been proposed or built from 1995–2016, and Chevron replaced half of its Richmond refinery's crude feed in five years, after expanding its FCC unit.[1, 6, 15, 46–59] Further, if heavy oil/bitumen blends were to replace the lighter current imports in the Bay Area refinery crude feed instead of its relatively denser California pipeline supply, the density of the crude feed and emissions from refining it could increase more rapidly. The low case emissions thus could occur early in the 2020–2050 forecast period. Meanwhile, the high case requires more oil infrastructure that takes more time to build, and Bay Area refineries may continue to build it piecemeal over decades, before the high case emissions could occur.

Data and forecasting limitations further inform the interpretation and use of this estimate:

Much of the pollution from refining lower quality oil that is asociated with Bay Area refineries is outside the scope of this estimate for direct emissions of energy-related pollutants. Examples include selenium and mercury contamination (see pp. 3–4)[4, 9, 10] and exports[63] of the dirty-burning coke byproduct from refining lower quality oil.[11] Future work should address these emissions.

Crude feed volume and "end-of-pipe" engineered controls affect refinery emissions, and the estimate holds those factors constant to better estimate oil quality-driven emissions. This supports addressing emissions related to the other factors in an important way: The estimate supports analysis of the potential for oil quality-driven emission increments to impede or foreclose the ability of other measures to achieve needed emission reductions.

Incomplete publicly reported data for many oil quality characteristics, plant-level product slates, and process-level inputs and outputs limit the reliability of this estimation method for predicting oil quality-driven emissions from individual refineries.[11–12, 18–22] This estimate of the *regional* refining industry's potential emissions should not be interpreted as an equally accurate prediction of potential emissions from individual plants.

Emissions could increase or decrease relative to this estimate if the mix of fuels refiners consume changes. Refiners' choices among hydrogen addition and carbon rejection technologies for converting denser oils to high-value products may change the emission intensity of the refinery fuel mix.[11] CO_2 emission impacts of changes in the refinery fuel mix have been shown to be small compared with those of oil quality-driven changes in energy intensity,[11, 12] however, the potential for changes in refinery fuels to affect other emissions should be addressed.[22] Increased by-production of gases from coking denser oils and bitumen may contaminate fuel gas that is burned refinery-wide, which might increase SO_2 and $PM_{2.5}$ emissions more than estimated here.[22]

Refiners could switch to better quality crude feeds than tar sands oil. This is feasible, less costly to society,[30] and would avoid the huge potential increase in climate and health threatening air pollution from refineries in the Bay Area that is forecast here. The emission limits proposed in Rule 12-16 would prevent this emissions increase and address this uncertainty.

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APPENDICES

A. Details of Predictions for Energy to Refine Lower Quality Oil, 2014.

B. Details of Predictions for Energy to Refine Lower Quality Oil, 2020–2050.

APPENDIX A. Details of Predictions for Energy to Refine Lower Quality Oil, 2014.

PADD	Year	*EI* (GJ/m^3)	*d* (kg/m^3)	*S* (kg/m^3)	*CapUt* (%)	*Pratio*
1	1999	3.451	858.20	8.24	90.9	3.668
1	2000	3.430	860.18	8.00	91.7	3.489
1	2001	3.518	866.34	7.71	87.2	3.479
1	2002	3.426	865.71	7.45	88.9	3.605
1	2003	3.364	863.44	7.43	92.7	3.321
1	2004	3.416	865.44	7.79	90.4	3.397
1	2005	3.404	863.38	7.17	93.1	3.756
1	2006	3.440	864.12	7.17	86.7	3.522
1	2007	3.499	864.33	7.26	85.6	3.443
1	2008	3.551	863.65	7.08	80.8	3.400
2	1999	3.368	858.25	10.64	93.3	4.077
2	2000	3.361	860.03	11.35	94.2	4.132
2	2001	3.396	861.33	11.37	93.9	4.313
2	2002	3.393	861.02	11.28	90.0	4.345
2	2003	3.298	862.80	11.65	91.6	4.281
2	2004	3.376	865.65	11.86	93.6	4.167
2	2005	3.496	865.65	11.95	92.9	4.207
2	2006	3.738	865.44	11.60	92.4	3.907
2	2007	3.800	864.07	11.84	90.1	4.161
2	2008	3.858	862.59	11.73	88.4	4.333
3	1999	4.546	869.00	12.86	94.7	3.120
3	2000	4.563	870.29	12.97	93.9	3.120
3	2001	4.348	874.43	14.34	94.8	3.128
3	2002	4.434	876.70	14.47	91.5	3.251
3	2003	4.381	874.48	14.43	93.6	3.160
3	2004	4.204	877.79	14.40	94.1	3.228
3	2005	4.205	878.01	14.40	88.3	3.316
3	2006	4.367	875.67	14.36	88.7	3.176
3	2007	4.226	876.98	14.47	88.7	3.205
3	2008	4.361	878.66	14.94	83.6	3.229
5	1999	4.908	894.61	11.09	87.1	2.952
5	2000	5.189	895.85	10.84	87.5	3.160
5	2001	5.039	893.76	10.99	89.1	3.231
5	2002	4.881	889.99	10.86	90.0	3.460
5	2003	4.885	889.10	10.94	91.3	3.487
5	2004	4.861	888.87	11.20	90.4	3.551
5	2005	4.774	888.99	11.38	91.7	3.700
5	2006	4.862	887.65	10.92	90.5	3.615
5	2007	5.091	885.54	11.07	87.6	3.551
5	2008	4.939	890.16	12.11	88.1	3.803
Data Inputs for Bay Area Refining in 2014						
Bay Area Refineries Actuals			891.71	11.70	97.7	3.871
Bay Area Refineries (SC – 20 %)			891.71	11.70	97.7	3.097
Bay Area Refineries (SC + 20 %)			891.71	11.70	97.7	4.645

Predictions for Energy Intensity (EI): Bay Area Refining in 2014

		95% Confidence Interval	
For EI (GJ/m^3)	Prediction	lower bound	upper bound
Bay Area Refineries Actuals	4.950	4.553	5.347
Bay Area Refineries (SC – 20 %)	5.073	4.703	5.443
Bay Area Refineries (SC + 20 %)	4.827	4.379	5.276

APPENDIX B. Details of Predictions for Energy to Refine Lower Quality Oil, 2020–2050.

Data Inputs from U.S. Refinery Observations

PADD	Year	*EI* (GJ/m^3)	*d* (kg/m^3)	*S* (kg/m^3)	*CapUt* (%)	*Pratio*
1	1999	3.451	858.20	8.24	90.9	3.668
1	2000	3.430	860.18	8.00	91.7	3.489
1	2001	3.518	866.34	7.71	87.2	3.479
1	2002	3.426	865.71	7.45	88.9	3.605
1	2003	3.364	863.44	7.43	92.7	3.321
1	2004	3.416	865.44	7.79	90.4	3.397
1	2005	3.404	863.38	7.17	93.1	3.756
1	2006	3.440	864.12	7.17	86.7	3.522
1	2007	3.499	864.33	7.26	85.6	3.443
1	2008	3.551	863.65	7.08	80.8	3.400
2	1999	3.368	858.25	10.64	93.3	4.077
2	2000	3.361	860.03	11.35	94.2	4.132
2	2001	3.396	861.33	11.37	93.9	4.313
2	2002	3.393	861.02	11.28	90.0	4.345
2	2003	3.298	862.80	11.65	91.6	4.281
2	2004	3.376	865.65	11.86	93.6	4.167
2	2005	3.496	865.65	11.95	92.9	4.207
2	2006	3.738	865.44	11.60	92.4	3.907
2	2007	3.800	864.07	11.84	90.1	4.161
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3	2000	4.563	870.29	12.97	93.9	3.120
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5	2002	4.881	889.99	10.86	90.0	3.460
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5	2004	4.861	888.87	11.20	90.4	3.551
5	2005	4.774	888.99	11.38	91.7	3.700
5	2006	4.862	887.65	10.92	90.5	3.615
5	2007	5.091	885.54	11.07	87.6	3.551
5	2008	4.939	890.16	12.11	88.1	3.803

Data Inputs for Bay Area Refining 2020–2050 Scenarios

	d (kg/m^3)	*S* (kg/m^3)	*CapUt* (%)	*Pratio*
Bay Area Refineries Low Case	924.56	19.75	90.3	3.871
Bay Area Refineries High Case	974.74	31.66	90.3	3.871

Predictions for Energy Intensity (EI): Bay Area Refining 2020–2050 Scenarios

		95% Confidence Interval	
For EI (GJ/m^3)	Prediction	lower bound	upper bound
Bay Area Refineries Low Case	6.802	6.356	7.248
Bay Area Refineries High Case	9.719	9.065	10.372

New Climate Threat: Will Oil Refineries Make California the Gas Station of the Pacific Rim?

Preventing climate disaster requires a global switch from oil before the year 2050.[1] On the U.S. West Coast, where Los Angeles, the Bay Area, and Puget Sound host the 1st, 2nd, and 3rd largest oil refining centers in Western North America,[2] we are using less oil.[3] So we should be leaders in this transition. But instead of switching to sustainable alternatives, as we use less oil, West Coast refiners are boosting production to sell other nations oil-derived fuels.

West Coast demand for finished petroleum products (orange in the charts) dropped from an average of approximately 3.1 million barrels per day in 2007 to ≈ 2.8 million b/d in 2014.[3] But at the same time, West Coast refinery production increased.

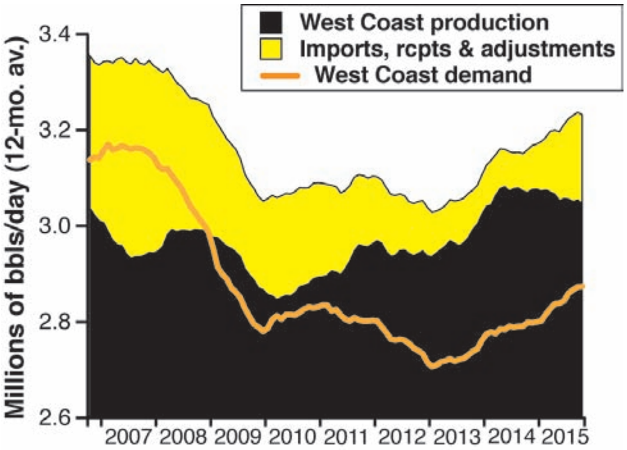
Production of finished petroleum products on the West Coast (black in the charts) increased from ≈ 2.9 million b/d in 2007 to ≈ 3.1 million b/d in 2014.[3] Production exceeded demand here by late 2008, and this production excess grew large after 2010,[3] as oil refiners made more fuel for export. Foreign exports of finished refined products from the West Coast (brown) nearly doubled, growing by nearly 200,000 b/d, from 2007 to 2014.[3]

Engine fuel exports are driving this excess refinery production. Increased gasoline, distillate/diesel and jet fuel exports account for the vast majority (74 %) of the total increase from 2007 to 2014 in finished petroleum products exports from the West Coast.[3]

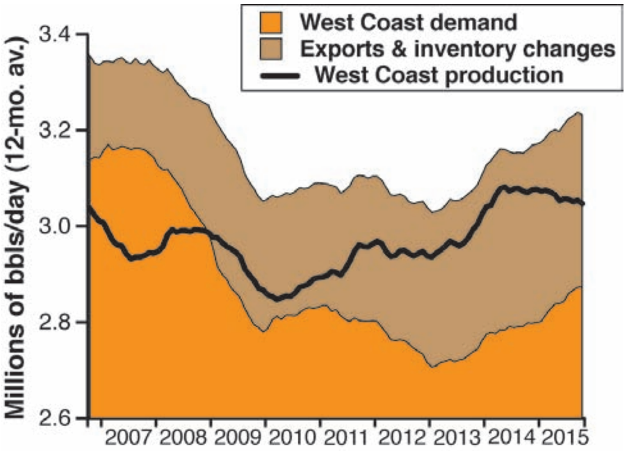
Petroleum coke exports remained the largest share of these exports by volume and also increased from 2007–2014,[3] but pet coke is a byproduct of refining low-quality crude that is exported in part because of air quality controls on this dirty-burning fuel.

California refiners account for 67 % of West Coast refining capacity[2] and made ≈ 84 % of the money from West Coast refined product exports in 2014.[4]

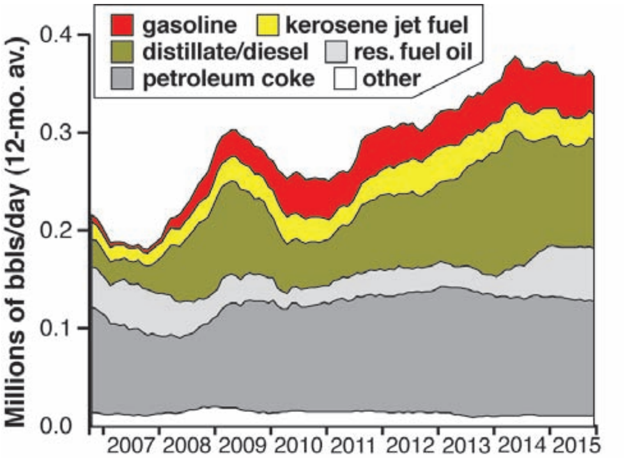
...continued



West Coast refined products supply exceeds West Coast demand, Oct 2006–Oct 2015[3]



West Coast refinery production increased to increase product export, Oct 2006–Oct 2015[3]



West Coast exports of distillate/diesel and gasoline increased from Oct 2006–Oct 2015[3]

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Gas Station of the Pacific Rim? *continued...*

Further, the major California refining centers, in the Los Angeles and San Francisco Bay areas, supply engine fuels to other states on the West Coast.

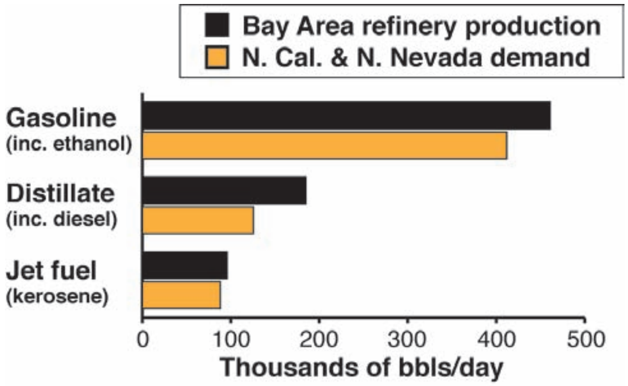
Bay Area refinery production of gasoline, distillate-diesel, and jet fuel exceeds demand in its primary regional markets—northern California and northern Nevada.[5] (*See* bar chart.) LA refinery production (not shown in chart) exceeds demand in its primary regional markets for diesel.[5] Bay Area refineries supply engine fuels to southern California and Oregon as well as to northern California and northern Nevada, while LA Area refineries supply southern California, southern Nevada and Arizona. (*See* map.) In 2013, Bay Area refiners exported ≈ 71 % of the distillate and virtually all the gasoline and jet fuel exported by California refineries.[5]

Across the Pacific, 3.5 billion people live in 21 Asian, Latin American and Oceanic nations that imported 442 million barrels (181 %) more oil products from the U.S. in 2014 than in 2007.[6] Their per capita oil demand is low and rising.[6] If it reaches half of today's U.S. per capita demand by 2050 and U.S. exports to them keep growing at half the 2007–2014 rate, total oil demand in these 21 nations, and total U.S. refinery exports to them, could grow by 24 times and 15 times current total West Coast refinery production, respectively.[6]

California is not yet the Pacific rim's gas station, and switching to solar electric cars can avoid that climate-killing scenario. But ***allowing*** oil refining for export to worsen air pollution from refineries here and from tailpipes everywhere ***allows*** oil to compete unfairly with this urgently needed solution.

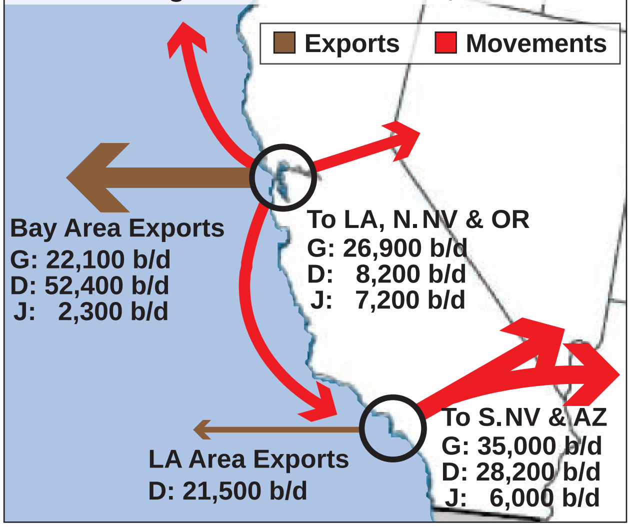
Bay Area refiners got more money exporting than other West Coast refining centers, 2014.

Refining Center	Exports in 2014[4]
San Francisco Bay Area	$ 4,376,000,000
Los Angeles Area	$ 3,519,000,000
Puget Sound Area, WA	$ 1,369,000,000
Bakersfield Area, CA	$ 650,000,000
Other areas (AK & HI)	$ 290,000,000



Bay Area refinery production of engine fuels exceeds N. Cal. and N. Nevada demand, 2013[5]

Exports and net movements of gasoline (G), distillate (D), and jet fuel (J) from Bay Area and Los Angeles Area refineries, 2013[5]



Notes. (**1**) *See* IPCC AR 5; and Williams et al., 2011. DOI: 10.1126/science.1208365. (**2**) Data from *Oil & Gas Journal* "2016 Worldwide Refining Survey." (**3**) Finished petroleum products data for AK, AZ, CA, HI, NV, OR and WA from *West Coast (PADD 5) Supply and Disposition;* Energy Information Admin. (EIA), 2015; www.eia.gov/dnav/pet/pet_sum_snd_d_r50_mbblpd_m_cur.htm. (**4**) Brookings Institute, 2015. *Export Monitor 2015;* data for petroleum & coal products exports produced by metro area (note that CA refining centers do not produce coal); www.brookings.edu/research/interactives/2015/export-m. (**5**) Data from EIA, 2015. *PADD 5 Transportation Fuels Markets;* www.eia.gov/analysis/transportationfuels/padd5. (**6**) Australia, Chile, China, Colombia, Costa Rica, Ecuador, El Salvador, Guatemala, India, Indonesia, Japan, Korea, Mexico, New Zealand, Nicaragua, Panama, Peru, Philippines, Singapore, Taiwan and Venezuela: per capita demand (3.17 b/y collectively in these nations *v.* 21.87 b/y in U.S.) based on 2013 data from databank.worldbank.org (population) and www.eia.gov/cfapps/ipdbproject/IEDIndex3.cfm?tid=5&pid=5&aid=2 (pet. consumption); U.S. oil products exports to these nations from EIA's *Total Products Exports by Destination;* www.eia.gov/dnav/pet/pet_move_expc_a_epp0_eex_mbblpd_a.htm; 2014 WC refinery production ≈ 3.1 million b/d (note **3**).

Independent Statistics & Analysis
U.S. Energy Information Administration

PADD 5 Transportation Fuels Markets

September 2015

Independent Statistics & Analysis
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U.S. Department of Energy
Washington, DC 20585

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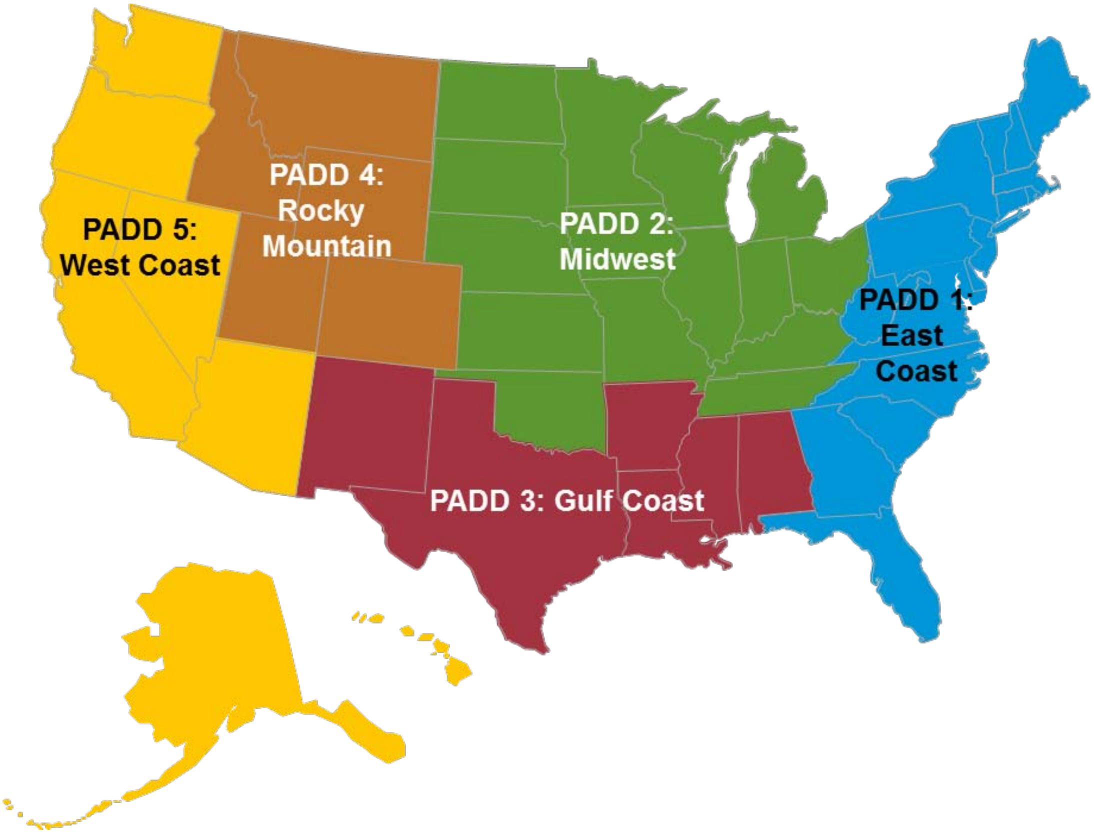
Introduction

This study examines supply, demand, and distribution of transportation fuels in Petroleum Administration for Defense District (PADD) 5, a region that includes the western states of California, Arizona, Nevada, Oregon, Washington, Alaska, and Hawaii. For this study, transportation fuels include gasoline, diesel fuel, and jet fuel.

This study is the first in a series of studies that the U.S. Energy Information Administration (EIA) plans to conduct to inform its analyses of petroleum product markets, especially during periods of supply disruption and market change.

Figure 1. Petroleum Administration for Defense Districts (PADDs)



Source: U.S. Energy Information Administration

This study examines transportation fuels supply, demand, and distribution at both the PADD level and for specific areas within the PADD, which are referred to as sub-PADD regions in this analysis. PADD 5 covers a large and diverse geography, and supply/demand balances and supply patterns vary within the region. The study identified six distinct regional markets within PADD 5: Southern California and Southern Nevada; Northern California and Northern Nevada; Pacific Northwest, which includes Washington and Oregon; Arizona; Hawaii; and Alaska.

For each of these regional markets as well as for PADD 5 as a whole, the study considers demand, supply, supply patterns, and distribution infrastructure, using 2013 as a base year and taking into account expected changes in balances and infrastructure in subsequent years. Demand includes in-region consumption, transfers of fuels to other parts of the United States (other PADDs) and to other regional markets within PADD 5, and exports to the global market. Supply includes in-region refinery production, receipts of fuels produced in other U.S. regions and other PADD 5 regional markets, and imports. Distribution infrastructure includes storage terminals, pipelines, rail facilities, marine loading and unloading facilities, and marine vessel availability.

EIA retained Stillwater Associates, an Irvine, California-based transportation fuels consultant, to conduct the research and analysis for the PADD 5 study. Stillwater analyzed data and information from EIA, the California Energy Commission (CEC), the Army Corps of Engineers Waterborne Commerce Statistics Center, and publicly available data from various sources.

Additional studies are planned to analyze PADD 5 crude supply, PADD 1 (East Coast), and PADD 3 (Gulf Coast) transportation fuels markets, and PADD 2 (Midwest) and PADD 4 (Rocky Mountains) transportation fuels markets.

Executive Summary

In 2013, PADD 5 accounted for 17%, or 1.5 million barrels/day (b/d), of total U.S. gasoline consumption, 13%, or 494,000 b/d, of distillate (including diesel fuel) consumption, and about 30%, or 430,000 b/d, of jet fuel consumption. Consumption varies across PADD 5 and is concentrated in California.

PADD 5 transportation fuels markets have features that often result in significant and persistent increases in prices in the wake of supply disruptions. The region is geographically isolated from other U.S. refining centers, notably the Gulf Coast, where 52% of U.S. refining capacity is located, and from global refining centers that can efficiently supply product to the U.S. East Coast (PADD 1). In addition, although pipelines can move products from the Gulf Coast as far north as New York Harbor on the East Coast, there are no pipelines that cross the Rocky Mountains to move product to the mainland states of PADD 5 from the Midwest, and only limited pipelines that deliver from the Gulf Coast to the southern regions of PADD 5 and from the small refineries in PADD 4 to the eastern regions of PADD 5. The West Coast is 10 days travel by tanker from the U.S. Gulf Coast, three weeks from Asia, and more than four weeks from Europe. Pipeline and marine infrastructure, as well as vessel availability to move product within PADD 5, are also limited.

Across PADD 5, specifications for motor gasoline and diesel fuel vary state-to-state and even within some states, making it difficult to cover product shortfall in one area with supply from another. In addition, some product specifications, like those for the California Air Resources Board (CARB) gasoline and diesel fuel, are difficult and costly to manufacture, and not all refineries in PADD 5, much less elsewhere in the United States or the rest of the world, can make such products. Even when refineries outside PADD 5 can manufacture product to meet these specifications, supplies generally are not kept on hand, further limiting resupply options when disruptions occur.

Because PADD 5 is isolated, in-region refineries are the primary source of transportation fuels for PADD 5. In 2013, PADD 5 refinery production was sufficient to cover about 91% of in-region motor gasoline demand, 96% of jet demand, and 113% of distillate demand. Heavy reliance on in-region production further complicates the supply chain when disruptions occur. When disruptions occur, all of these factors noted above combine to limit short-term supply options, lengthen the duration of supply disruptions, and cause prices to increase and remain higher for a longer period than would be typical in markets outside PADD 5.

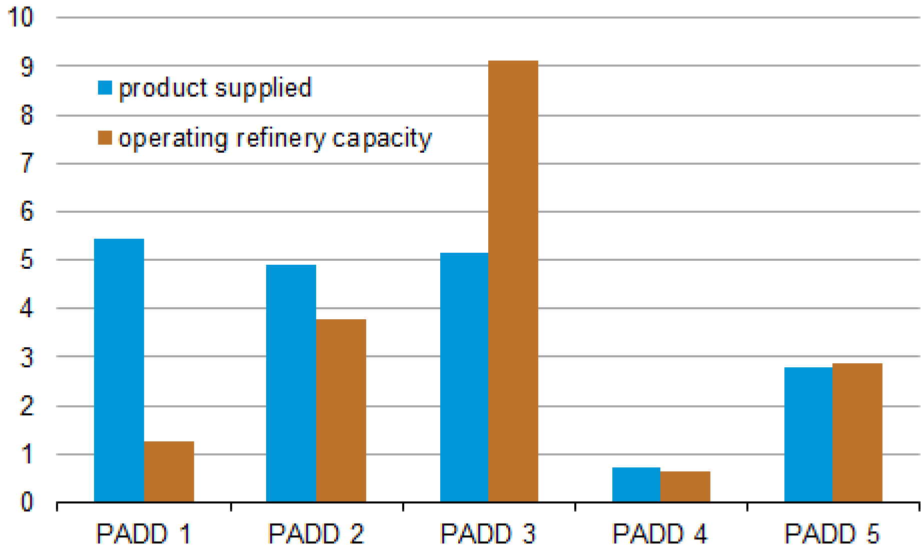
The recent increase in gasoline prices on the West Coast following a series of supply disruptions that started with an unplanned refinery outage in February at a Southern California refinery provides a case in point. On February 18, an explosion and fire occurred at the third-largest refinery in Southern California. West Coast product markets reacted immediately to the potential loss of supply from the refinery, and spot gasoline prices quickly increased. The rapid price response is not unusual and is similar to what happened following past unplanned outages in that region. In the five weeks following the outage, West Coast total motor gasoline inventories decreased by 3.0 million barrels (10%), and remained below the five-year average for most weeks through August. Inventories provide an immediate, although limited, source of alternative supply but typically are insufficient to offset a prolonged market disruption. With limited resupply options from within the region and from within the

United States, imports increased to replace in-region production. Because the refinery outage has not yet been resolved as of the writing of this report, PADD 5 has continued to rely on imports, which has lengthened the supply chain, making the region more susceptible to shipping delays and other supply chain disruptions. Gasoline prices on the West Coast increased sharply again in early July when, according to trade press, shipping delays caused gasoline cargoes destined for the West Coast to arrive later than anticipated. In addition, PADD 5 gasoline demand was up 4% in the first six months of 2015 compared with the same time last year, putting additional pressure on the supply chain.

There are 22 operating refineries in Washington, Oregon, California, Nevada, and Arizona, the mainland states of PADD 5. These refineries, which have total atmospheric distillation unit (ADU) capacity of 2.5 million barrels per calendar day (b/cd), are located primarily in and around Los Angeles and San Francisco, California, and Puget Sound in Washington. There are two operating refineries in Hawaii with combined crude distillation processing capacity of 147,500 b/cd and five operating refineries in Alaska with combined crude distillation capacity of 165,200 b/cd.

Figure 2. Petroleum product supply and refining capacity by PADD

million barrels per day



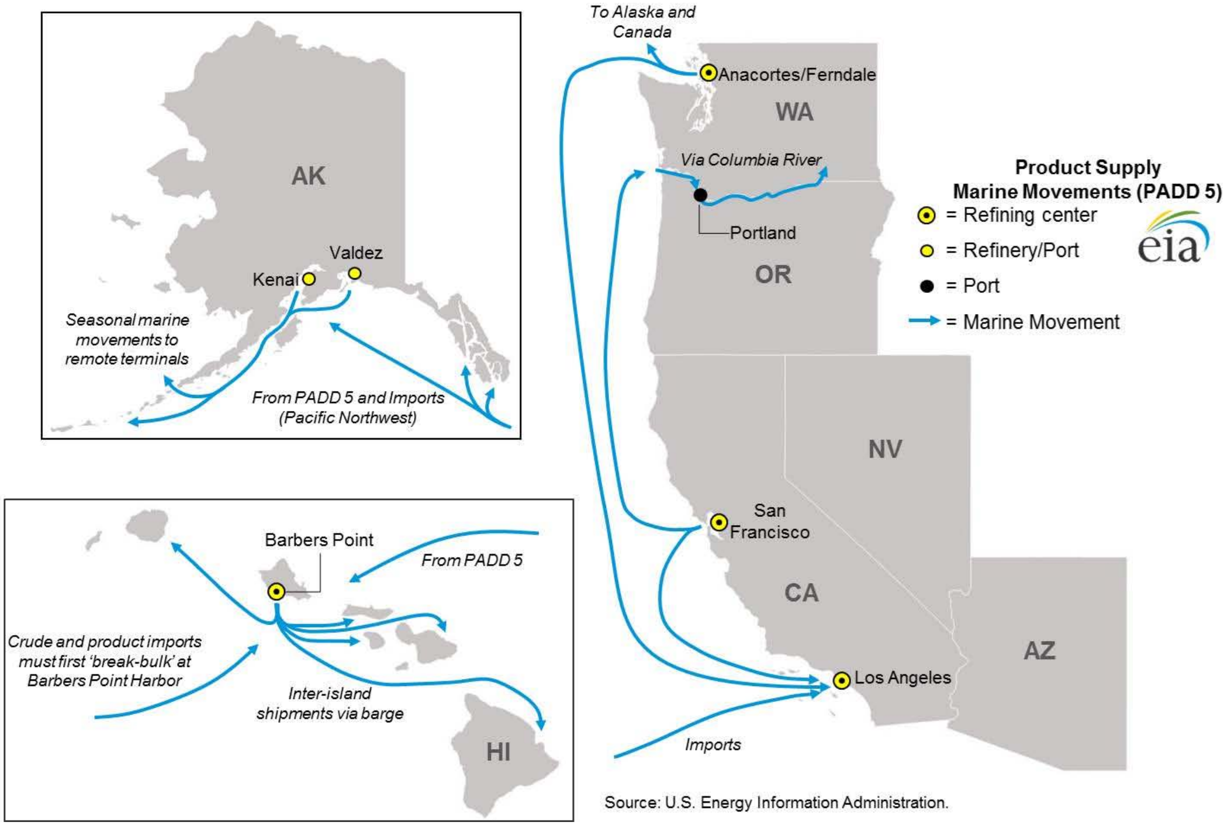
Note: Refinery capacity is in barrels per calendar day.
Source: U.S. Energy Information Administration

This study identified six distinct sub-PADD regional markets within PADD 5, each of which is characterized by different supply patterns for transportation fuels and each of which interacts differently with the other regions within PADD 5 and the global markets. The six regions are:

- Southern California and Southern Nevada
- Northern California and Northern Nevada
- Arizona
- Pacific Northwest, which includes Washington and Oregon
- Alaska
- Hawaii

PADD 5 is just not one market for transportation fuels, but rather six distinct regional markets. These six regional markets vary significantly in demand, how transportation fuels are supplied, especially the share of supply provided by in-region refineries, and product distribution patterns. Because there is limited pipeline infrastructure connecting the six regional markets, marine movements within PADD 5 play a key role in moving transportation fuels from regions with excess supply to regions with supply shortfalls. As a result, marine vessels are generally highly utilized, and there is minimal capacity to increase intraregional shipments to manage supply disruptions.

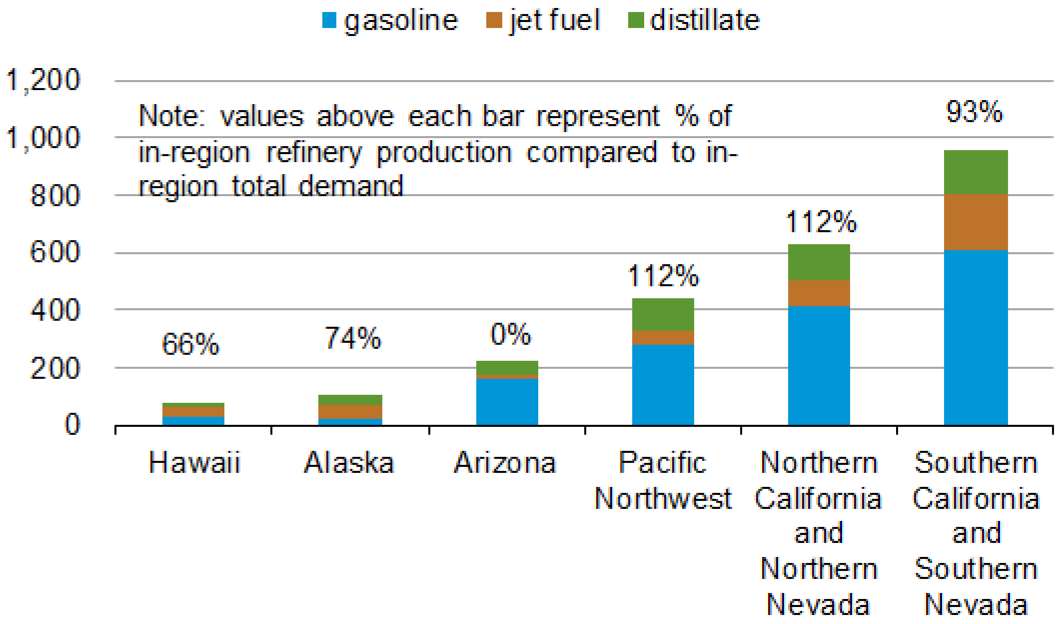
Figure 3. PADD 5 marine movements



Source: U.S. Energy Information Administration.

Figure 4. PADD 5 2013 average regional transportation fuel demand by product

thousand barrels per day



Source: Stillwater Associates analysis of EIA data

Southern California and Southern Nevada

The Southern California and Southern Nevada (SCSN) region includes the southernmost counties of California[1] as well as the Las Vegas metropolitan area of Southern Nevada. The region accounts for more than 40% of total PADD 5 motor gasoline demand, and about 7% of total U.S. demand. Because of the many military air bases and large commercial aviation hubs, jet fuel demand in the SCSN region accounts for about 45% of total PADD 5 jet fuel demand and 14% of U.S. demand. SCSN accounts for 32% of total PADD 5 distillate fuel demand, which is about 4% of U.S. demand.

A combination of in-region refinery production, marine-delivered fuels produced at refineries in Northern California and Washington, receipts of fuels produced at refineries in other PADDs, and imports from the global market supply the SCSN region with transportation fuels. The regional refineries do not produce sufficient gasoline or jet fuel to meet in-region demand but produce more distillate than is consumed in the region. In-region refinery production is supplemented with marine deliveries of product from refineries in Northern California and Washington as well as imports from the global market. Transportation fuels produced at SCSN refineries also supply Arizona, and some are exported into the global market. Exports are primarily distillate fuel, which might not meet region specifications.

There are eight operating refineries in the Southern California and Southern Nevada region. In 2013, SCSN refineries produced a total of 526,800 b/d of gasoline, 182,500 b/d of distillate, and 178,100 b/d of

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[1] The southernmost counties of California are Imperial, Kern, Los Angeles, Orange, Riverside, San Bernardino, San Diego, San Luis Obispo, Santa Barbara, and Ventura.

jet fuel, production sufficient to supply 87% of regional motor gasoline demand, 117% of total distillate fuel demand, and 92% of jet fuel demand.

Production from the refineries moves primarily by pipeline from the Los Angeles area to bulk storage and distribution terminals throughout the SCSN region. From terminals, product moves by tank truck to retail outlets. Product from the Los Angeles area is also shipped by pipeline to Arizona, reducing the product available to supply SCSN demand, which is particularly important for gasoline. Transportation fuels produced at refineries in Salt Lake City, Utah, in PADD 4, also supply SCSN.

Refineries, pipelines, ports, and storage facilities are all critical to the effective functioning of the petroleum supply chain. However, in the SCSN region, Watson Station, a pipeline hub in Carson, California, is particularly important. Product from many of the region's refineries must move through Watson Station to reach bulk storage and distribution facilities. Power outages and earthquakes can affect the region’s infrastructure.

There are about 27 distinct branded companies participating in the retail market for gasoline and distillate fuel in the Southern California and Southern Nevada region. About 76% of retail outlets are branded, meaning that they are associated with and display a major oil company brand, like Chevron, Shell, 76, Valero, and ARCO. The remaining 24% of retail outlets are referred to as unbranded because they are not affiliated with a major oil company brand. Unbranded retailers include small independent retailers as well as big box retailers. In California as a whole, 79% of retail outlets are associated with a major brand, while 21% are unbranded.

Northern California and Northern Nevada

The Northern California and Northern Nevada region (NCNN) includes counties in California north of San Luis Obispo, Kern, and San Bernardino counties, and in Nevada north of Las Vegas. In 2013, with average motor gasoline demand of 412,000 b/d, the region accounted for 27% of total PADD 5 motor gasoline demand and 5% of U.S. motor gasoline demand. NCNN distillate demand of 125,000 b/d in 2013 accounted for 25% of PADD 5 demand and 3% of U.S. demand. NCNN jet fuel demand averaged 88,000 b/d in 2013, 21% of PADD 5 demand and 6% of U.S. demand.

The region is supplied by in-region refinery production, and refineries in the region produce more motor gasoline, jet fuel, and diesel fuel than is consumed in the region. As a result, NCNN supplies other regional markets in PADD 5, primarily Southern California and Southern Nevada, with motor gasoline, jet fuel, and diesel fuel, and also exports these products. In 2013, the region exported 22,100 b/d of gasoline, 2,300 b/d of jet fuel, and 52,400 b/d of distillate fuel, primarily to Central America and South America.

There are nine operating refineries in two primary refining centers in the Northern California and Northern Nevada region. Only one of the refineries is located outside California, and it primarily produces asphalt. Most of the California refining capacity in the NCNN region is in the San Francisco Bay area. Several smaller refineries are located in California’s Central Valley.

In 2013, NCNN refineries produced an average of 421,000 b/d of motor gasoline and motor gasoline blending components, 185,000 b/d of distillate, and 96,000 b/d of jet fuel. This production was more than sufficient to meet in-region demand. NCNN refineries produced product sufficient to meet 102% of regional demand for finished motor gasoline,[2] 108% of jet fuel demand, and 147% of diesel fuel demand. Production from refineries in Northern California regularly supplies parts of Southern California and Oregon by marine vessel.

Product is shipped by pipeline from the refineries in San Francisco to storage and distribution terminals in the San Francisco area and further inland to Fresno and Chico, California, and to Nevada. No pipelines connect the NCNN region to other PADDs or other PADD 5 regional markets, and, as a result, supply from NCNN to those areas moves by marine vessel. The major port facilities through which products are exported into the global market and from which products are shipped to other PADD 5 regional markets are located on the San Francisco Bay.

Critical supply chain infrastructure includes the refineries, pipelines, ports, and storage facilities of the San Francisco Bay area. In particular, the Concord pipeline junction is the gathering and entry point for the main pipeline distribution artery for the region. Power outages and earthquakes can affect the region’s infrastructure, and heavy fog can disrupt the port facilities on the San Francisco Bay.

In the Northern California/Northern Nevada region, 80% of retail outlets are branded and 20% are unbranded. In Northern California, about 21 companies participate in the retail market for gasoline and diesel fuel as compared with about 12 in the Reno/Carson City market. In Northern California, major oil company branded outlets dominate the retail sector, and the top five brands have 76% of the number of retail outlets. A mix of branded and unbranded retail outlets characterizes the Reno/Carson City market.

Pacific Northwest

The Pacific Northwest region (PNW) includes the states of Oregon and Washington. In 2013, with 277,300 b/d of motor gasoline demand, the region accounted for 18% of total PADD 5 motor gasoline demand and 3% of total U.S. demand. At 111,400 b/d, PNW demand for distillate fuel was 23% of PADD 5 demand and 3% of U.S. demand. Jet fuel demand in the Pacific Northwest averaged 51,400 b/d in 2013, 12% of PADD 5 demand and 4% of U.S. demand.

The region is supplied by a combination of in-region refinery production, imports, and receipts of product manufactured at refineries outside PADD 5. Refineries in the PNW produce about as much gasoline as is consumed in the region, but considerably more than enough distillate and jet fuel than is needed to meet in-region demand. The region supplies distillate fuel and jet fuel to the global market and to other regions within PADD 5 and exports motor gasoline. The PNW also imports motor gasoline and a small amount of distillate. The combination of imports and exports is used to manage distribution system inefficiencies and gasoline grade imbalances. The PNW typically does not receive product from other regions within PADD 5. In 2013, the region exported 26,000 b/d of motor gasoline, 26,800 b/d of jet fuel, and 43,200 b/d of distillate fuel, primarily to Canada, Mexico, Central America, and South America.

There are five operating refineries in the Pacific Northwest region, located in and around Puget Sound, Washington. There are no refineries in Oregon or eastern Washington.

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[2] Finished motor gasoline includes gasoline blendstock produced by refineries and 10% ethanol.

In 2013, PNW refineries produced an average of 253,400 b/d of motor gasoline and motor gasoline blending components, 154,100 b/d of distillate fuel, and 83,600 b/d of jet fuel. This production was sufficient to meet 102% of regional demand for motor gasoline, 163% of jet fuel demand, and 140% of diesel fuel demand. Production from refineries in Washington regularly supplies Alaska and California.

Product is shipped from the refineries by pipeline north and south to supply Portland, Oregon, and Seattle, Washington, and product is shipped by marine vessel to supply the global markets and other regions within PADD 5. Many of the Portland storage and distribution terminals have access to the Columbia River and can ship and receive product by marine vessel. Each of the five refineries also has associated dock infrastructure for loading and discharging marine vessels, which supports imports and exports of petroleum products.

Product moves from storage and distribution terminals in Portland south to Eugene, Oregon by pipeline. Distribution infrastructure to move product from the western portions of Washington and Oregon eastward is limited. The only connection between the western and eastern portions of the region is marine transport along the Columbia River. There is no pipeline infrastructure to move product across the Cascade Range of mountains. As a result, eastern Washington is supplied with product from refineries in PADD 4. Product moves by pipeline from Salt Lake City, Utah, into eastern Washington and Oregon, and from refineries in Billings, Montana, into eastern Washington.

Critical infrastructure in the region includes the refinery complexes, pipelines, storage and distribution terminals, and the marine facilities at refineries and terminals, notably those along the Columbia River. Weather can disrupt the region's marine facilities. The Olympic pipeline, which runs from Puget Sound, Washington, to Portland, Oregon, is the main north-south corridor for petroleum product transportation in the region. Disruptions to flows on the Olympic pipeline can have a major effect on regional supply. Many of the storage and distribution terminals connected to the pipeline lack other supply options. As a result, during supply disruptions product typically supplied from these terminals may need to be sourced from other terminals, which can increase supply costs and therefore prices.

The Pacific Northwest has a slightly higher percentage of branded outlets compared to PADD 5 overall. The region has about 25 branded retailers, with 77% of retail stations selling branded fuels compared to the PADD 5 average of 72%. Brands in the Pacific Northwest include Chevron, Shell, 76, Conoco, and ARCO along with Pilot, Costco, and Sam's Club.

Arizona

Arizona accounts for 11% of PADD 5 demand for motor gasoline, 3% of demand for jet fuel, and 10% of distillate fuel demand. There are no petroleum refineries in Arizona, and the region is supplied with product by pipelines that originate in Southern California and West Texas. In 2013, the region consumed 161,500 b/d of motor gasoline, 14,600 b/d of jet fuel, and 50,600 b/d of distillate fuel.

The Kinder Morgan East Line originates in El Paso, Texas, and consists of two parallel pipelines that end in Phoenix, Arizona. Refineries in West Texas and New Mexico supply product into the East Line for delivery to four storage and distribution terminals in Phoenix and two in Tucson, Arizona. The Kinder Morgan West Line runs from Watson in the Los Angeles Basin to Phoenix, Arizona, and delivers product into storage and distribution terminals in Phoenix.

The two pipelines of the East Line operate at very close to full capacity, while the West Line operates well below its capacity, and as a result, is a source of incremental supply for Phoenix should supply from the East Line be reduced. However, as the transportation time for fuels delivered into Phoenix from Los Angeles is about a week to 10 days, incremental supply to Phoenix will not be immediately available. Fuels cannot be delivered from Phoenix to Tucson by pipeline; thus, there is no backup pipeline capacity for fuels supply into Tucson. Incremental supply to Tucson is via long-haul trucking.

The Kinder Morgan East and West Lines are critical to fuels supply to Arizona. Train derailments, as well as washouts and pipeline ruptures, have affected the pipeline, sections of which lie in the Union Pacific Railroad right of way. Most disruptions have been of short duration.

There are about 23 distinct fuels retailers operating in Arizona, and most (56%) of the retail outlets are unbranded. Major retail brands in Arizona include Chevron, Circle K, Fry's, QuikTrip, Shell, and Valero.

Hawaii

Hawaii is remote and isolated from other PADD 5 regional markets and other PADDs, and relies primarily on in-region refinery production and imports. In 2013, refineries in Hawaii produced 21,500 b/d of motor gasoline, 20,300 b/d of jet fuel, and 11,800 b/d of diesel fuel sufficient to meet 72% of motor gasoline demand, 55% of jet fuel demand, and 81% of distillate fuel demand. Refinery production was supplemented with motor gasoline imports of 5,400 b/d, jet fuel imports of 19,700 b/d, and distillate imports of 2,200 barrels per day. Hawaii was also supplied with small volumes of motor gasoline and diesel fuel from other PADDs and a small volume of diesel fuel from other PADD 5 regional markets.

The state's island geography supports air travel, and as a result Hawaii's jet fuel demand, which averaged 37,000 b/d in 2013, is higher than demand for both motor gasoline and diesel fuel. Hawaii's jet fuel demand accounted for 8% of PADD 5 demand in 2013, compared with 2% of motor gasoline and 3% of distillate fuel demand. The state's distillate demand is boosted by demand from the electric power sector and U.S. Navy demand for marine fuels.

There are two operating refineries in Hawaii, both on the island of Oahu. One of the two refineries was closed for part of 2013 and changed ownership. As a result, 2013 data on refinery transportation fuels supply are atypical for Hawaiian petroleum product markets.

In 2013, refineries in Hawaii produced 21,500 b/d of motor gasoline, 20,300 b/d of jet fuel, and 11,800 b/d of distillate fuel, sufficient to meet 72% of motor gasoline demand, 55% of jet fuel demand, and 81% of distillate fuel demand. Refinery production was supplemented with motor gasoline imports of 5,400 b/d, jet fuel imports of 19,700 b/d, and diesel imports of 2,200 b/d. Hawaii was also supplied with small volumes of motor gasoline and diesel fuel from other PADDs and a small volume of diesel fuel from other PADD 5 regional markets. In addition to transportation fuels, Hawaiian refineries produce significant quantities of heavy fuels used in electric power generation.

The two refineries on Oahu and the Barbers Point port facilities and associated barge fleet are critical to Hawaii. Product from the refineries on Oahu moves by pipeline to supply storage and distribution terminals on Oahu and moves by marine vessel from the Barbers Point Harbor to terminals on the islands of Maui, Kauai, and Hawaii. Product that arrives in Hawaii by marine vessel from imports and other U.S. regions is also processed through the Barbers Point Harbor, where large seagoing marine vessels can be accommodated. Product is also shipped to the Honolulu International Airport by pipeline across Pearl Harbor, and jet fuel is delivered by truck from Honolulu area terminals. Large cargoes are offloaded, and smaller volumes are shipped by barge to the storage and distribution terminals on the other islands. There are 14 storage and distribution terminals outside the Honolulu area, many of which are very small.

There are about nine distinct retailers of transportation fuels in Hawaii, and 76% of retail outlets sell branded fuels. Chevron, 76, Aloha, Tesoro, and Shell are among the major retail brands in Hawaii.

Alaska

Alaska has the lowest population of all PADD 5 regions, and as a result, Alaska's demand for motor gasoline accounts for a small percentage of total PADD 5 demand. However, the region’s remoteness and wide geographic expanse make air travel essential and make Alaska demand for jet fuel higher than for motor gasoline. PADD 5 diesel fuel demand is supported by resource extraction activities and oil production in the north. In 2013, Alaska demand for motor gasoline was 20,800 b/d, less than 2% of total PADD 5 demand; jet fuel demand was 48,400 b/d, 11% of PADD 5 demand; and diesel fuel demand was 33,400 b/d, 7% of PADD 5 demand.

The region is supplied primarily by in-region refinery production, production from refineries in other regions of PADD 5 that is delivered by marine vessel from Washington and California, and imports.

There are five operating refineries in Alaska. A sixth refinery, Flint Hills Resources North Pole refinery, closed in 2014 and is being dismantled and converted to a storage and distribution terminal. Tesoro operates the largest and most complex refinery in Alaska at Kenai. The Tesoro refinery produces a wider range of transportation fuels, including motor gasoline, jet fuel, and diesel fuel. The refinery also produces asphalt. The other operating refineries are dispersed across the state. On the North Slope, two of the three major crude oil producers operate small distillation-only refineries that produce arctic diesel fuel for production operations. The refineries inject unsold distillation products back into the Trans-Alaska Pipeline System (TAPS). Two other distillation-only refineries, one in North Pole in central Alaska and the other in Valdez in southern Alaska, also blend unsold distillation products back into TAPS.

On an annual average basis, the refineries in Alaska supply 83% of motor gasoline demand, 76% of jet fuel demand, and 66% of diesel fuel demand. However, Alaska’s seasonal weather patterns result in seasonal differences in consumption, and supply/demand balances and supply patterns vary over the year. In-region refinery supply is supplemented with receipts from other PADD 5 regions and imports. Product is regularly supplied to southeastern Alaska by marine vessel from Washington and California. Alaska also exports a small amount of fuel to Canada and Asia.

Product is moved within Alaska by pipeline between Kenai and Anchorage, by rail between Anchorage and Fairbanks, and by marine vessel. The Anchorage-to-Fairbanks rail line and the pipeline to Anchorage are critical to the supply chain. Jet fuel is delivered to the Ted Stevens International Airport via both pipeline and trucks from Anchorage-area terminals.

There are 42 small storage/distribution terminals outside the Anchorage area that serve isolated areas. Deliveries to some locations are seasonal, occurring only during the summer and fall when barge movements are possible. In southeast Alaska, where there are few roads, fuels are supplied by barge from the U.S. West Coast and from Canada.

There are 9 distinct retailers with approximately 170 retail outlets in Alaska. Most of the retail locations (57%) are branded. Major retail brands include Holiday, Tesoro, Chevron, and Shell.

PADD 5 Overview

PADD 5 accounts for 17%, or 1.5 million barrels/day (b/d), of total U.S. gasoline consumption, 13%, or 494,000 b/d, of distillate (including diesel fuel) consumption, and about 30%, or 430,000 b/d, of jet fuel consumption. Consumption varies across the PADD and is concentrated in California (Table 1).

Table 1. Transportation fuels consumption within PADD 5: regional market breakdown

thousand barrels per day

	Gasoline[1]			Jet fuel			Diesel fuel		
Demand by region	**2013**	**% of PADD 5**	**% of U.S.**	**2013**	**% of PADD 5**	**% of U.S.**	**2013**	**% of PADD 5**	**% of U.S.**
Southern California/ Southern Nevada	606.6	40.2%	6.9%	194.1	44.8%	13.5%	155.5	31.7%	4.1%
Northern California/ Northern Nevada	412.0	27.3%	4.7%	88.2	20.3%	6.1%	125.6	25.6%	3.3%
Pacific Northwest	277.3	18.4%	3.1%	51.4	11.9%	3.6%	111.4	22.7%	2.9%
Arizona	161.5	10.7%	1.8%	14.6	3.4%	1.0%	50.6	10.3%	1.3%
Hawaii	29.6	2.0%	0.3%	36.7	8.5%	2.6%	14.6	3.0%	0.4%
Alaska	20.8	1.4%	0.2%	48.4	11.2%	3.4%	33.4	6.8%	0.9%
Total	**1,507.7**	**100%**	**17.0%**	**433.3**	**100.0%**	**30.2%**	**491.1**	**100.0%**	**12.8%**

[1] Finished motor gasoline, i.e., petroleum-based gasoline blendstock plus ethanol.
Source: U.S. Energy Information Administration

Transportation fuels supply

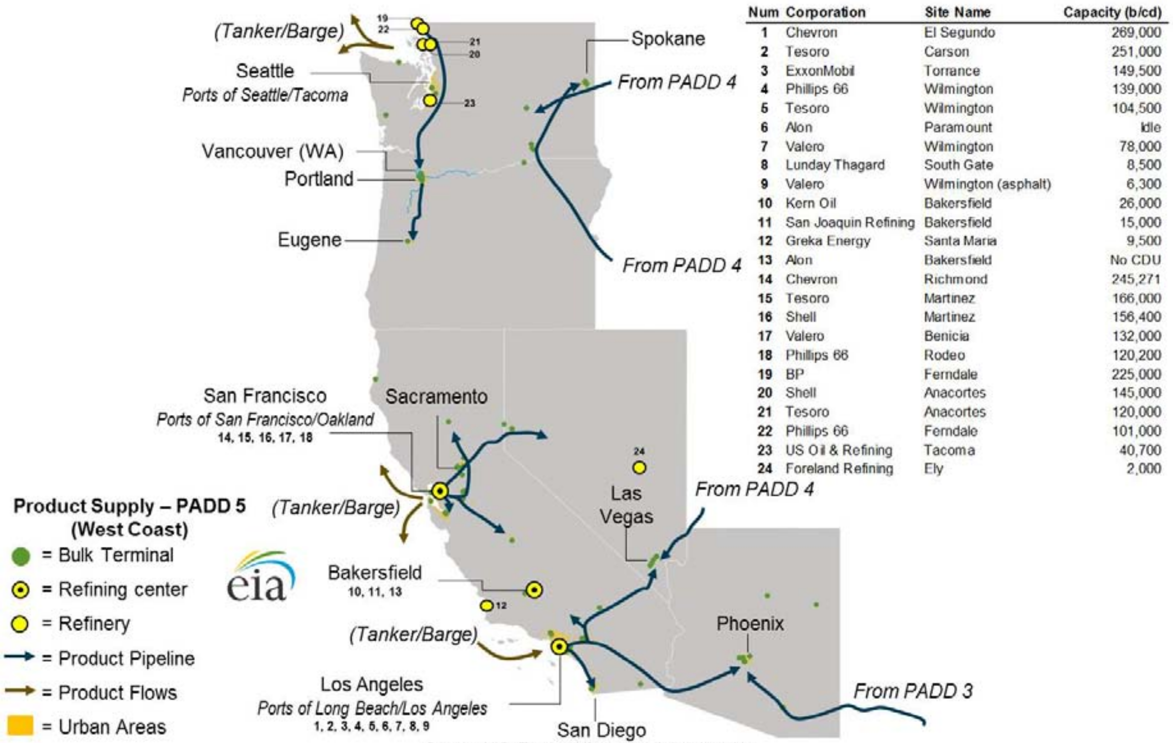
PADD 5 refineries are the primary source of transportation fuels for the region. There are 22 operating refineries in Washington, Oregon, California, Nevada, and Arizona, the mainland states of PADD 5. These refineries, which have total atmospheric crude distillation unit (ACDU) capacity of 2.5 million barrels per calendar day (b/cd), are located primarily in and around Los Angeles and San Francisco, California and Puget Sound in Washington State.

There are two operating refineries in Hawaii with combined crude distillation processing capacity of 147,500 b/cd and five operating refineries in Alaska with combined atmospheric crude distillation capacity of 165,200 b/cd.

PADD 5 depends largely on in-region refinery production of motor gasoline, jet fuel, and diesel fuel because of the relative geographic isolation of the region from other U.S. refining centers, like the Gulf Coast, and global refining centers, like Asia and Europe. There are no pipelines that cross the Rocky Mountains from PADD 4 (Rocky Mountains) and only limited pipelines that deliver to PADD 5 from PADD 3 (Gulf Coast). The West Coast is 10 days travel by tanker from the Gulf Coast and three weeks from Asia. In addition, much of PADD 5 requires the use of unique transportation fuels that are difficult and expensive to manufacture, notably California Air Resources Board (CARB) gasoline, and only a limited number of refineries outside PADD 5, both inside and outside the United States, can manufacture product that meets these unique specifications.

The interior markets of mainland PADD 5, which include Arizona, Las Vegas, Nevada, and eastern Washington, are less reliant on PADD 5 refineries as these markets can be supplied with transportation fuels produced at refineries in PADD 3 and PADD 4.

Figure 5. PADD 5 mainland refineries and product flows



Num	Corporation	Site Name	Capacity (b/cd)
1	Chevron	El Segundo	269,000
2	Tesoro	Carson	251,000
3	ExxonMobil	Torrance	149,500
4	Phillips 66	Wilmington	139,000
5	Tesoro	Wilmington	104,500
6	Alon	Paramount	Idle
7	Valero	Wilmington	78,000
8	Lunday Thagard	South Gate	8,500
9	Valero	Wilmington (asphalt)	6,300
10	Kern Oil	Bakersfield	26,000
11	San Joaquin Refining	Bakersfield	15,000
12	Greka Energy	Santa Maria	9,500
13	Alon	Bakersfield	No CDU
14	Chevron	Richmond	245,271
15	Tesoro	Martinez	166,000
16	Shell	Martinez	156,400
17	Valero	Benicia	132,000
18	Phillips 66	Rodeo	120,200
19	BP	Ferndale	225,000
20	Shell	Anacortes	145,000
21	Tesoro	Anacortes	120,000
22	Phillips 66	Ferndale	101,000
23	US Oil & Refining	Tacoma	40,700
24	Foreland Refining	Ely	2,000

Source: U.S. Energy Information Administration

As a whole, PADD 5 refineries do not produce sufficient gasoline or jet fuel to meet total PADD 5 demand, but they produce more distillate than is consumed in the region. For 2013, PADD 5 refinery production of gasoline was sufficient to supply 91%[3] of PADD 5 demand, 96% of jet demand, and 113% of distillate demand. However, refinery production in two PADD 5 regional markets, Northern California/Northern Nevada and the Pacific Northwest, typically is sufficient to meet local demand under normal refinery operating conditions.

PADD 5 refinery production is supplemented by receipts of fuels produced at refineries in other PADDs and imports of petroleum products from the global market. Diesel fuel is exported to balance overall supply and demand, and other transportation fuels produced at PADD 5 refineries are also exported, to balance any mismatch between the quality of product that refineries can produce and the quality of product demanded, but also to manage distribution system inefficiencies. Distillate fuel makes up most exports, but some gasoline and jet fuel is also exported. Some exported product does not meet PADD 5 product specifications.

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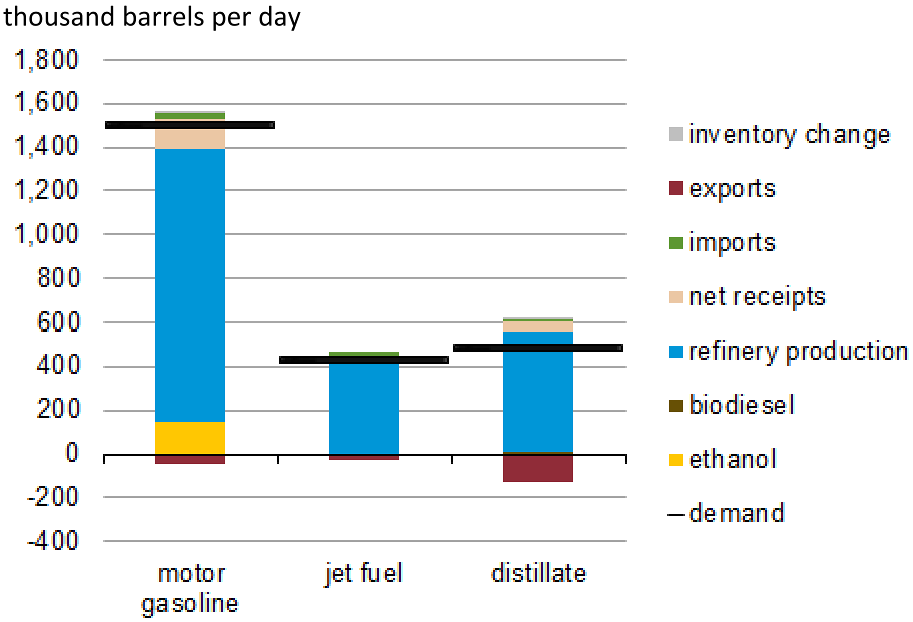
[3] 2013 PADD 5 demand for gasoline was 1,507.7 b/d of which about 90%, or 1,359.03.9 b/d, was petroleum-based gasoline blendstock (BOB). An additional 10% was ethanol. PADD 5 refineries produced 1,240.4 b/d petroleum-based gasoline, 90% of petroleum-based gasoline demand.

Figure 6. PADD 5 2013 supply/demand balance



Note: Net receipts are movements of product to and from other PADDs.
Source: Stillwater Associates analysis of EIA data

Product specifications

Gasoline and diesel specifications vary across PADD 5, complicating the supply chain and sometimes making it difficult to cover product shortfall in one region with oversupply from another. For example, California requires reformulated gasoline that meets specifications defined by the California Air Resources Board (CARB), so-called CARB gasoline, while other areas of PADD 5 require reformulated gasoline that meets the specifications defined by the U.S. Environmental Protection Agency[4] (EPA). Arizona requires cleaner-burning gasoline for ozone and carbon monoxide nonattainment areas in the state, the latter to comply with the EPA Oxygenated Fuel specification.[5]

Table 2 provides information on gasoline specifications for different areas of PADD 5.

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[4] Reformulated gasoline (RFG) is gasoline blended to burn more clearly than conventional gasoline and to reduce smog-forming and toxic pollutants in the air. The RFG program was mandated by Congress in the 1990 Clean Air Act amendments, and RFG is required in cities with high smog levels and is optional elsewhere. RFG is currently used in 17 states and the District of Columbia. About 30% of gasoline sold in the United States is reformulated.

[5] Federal EPA Winter Oxygenated Fuel programs increase fuel oxygen and are mandated in certain areas for carbon monoxide control. The winter oxygenated fuel season is generally October through February or March.

Table 2. PADD 5 gasoline specifications

Specifications	California Summer CARBOB Regular Grade	Nevada Summer CBOB Regular Grade	Arizona Summer AZBOB Regular Grade	Sub-Octane Conventional Regular Grade	Federal Reformulated RBOB Regular Grade[6]	Conventional Regular Grade[6]
Summer Reid Vapor Pressure (psi max)[1]	5.99	9.0/7.8	5.7	8.0 [2]	Varies [3]	9
Distillation T50 (deg. F)[1]	232	170 min	E200 (25-65%)	170 min	E200 (30-70%)	250
Distillation T90 (deg. F, max)[1]	335		E300 (65-100%)		E300 (70-100%)	374
Benzene (vol % max)[4]	1.22					3.8
Aromatics (vol % max)[1]	38.7	25	55		50	-
Olefins (vol % max)[1]	11.1		27.5			
Sulfur (PPM wt% max)[1, 4]	21	80	89	80	80	80
Road Octane (R+M/2)[5]	87	87	87	87	87	87

[1] These values are caps. These properties as well as others are inputs into the CARB and Federal Complex models.
[2] If RVP waiver applies, this is 9 psi max.
[3] Varies by state or local requirements and whether RVP waiver applies.
[4] Benzene and sulfur are subject to annual averaging requirements. Annual averages are 1.0% and 30 ppm maximum for benzene and sulfur respectively.
[5] Octane after blending with 10% ethanol (EtOH).
[6] Specifications generally used for exports.
Source: Kinder Morgan Pacific Operations Specification Manual, Colonial Pipeline Company Product Codes and Specifications

Diesel fuel sold in California must meet the unique CARB diesel specifications.[6] These stringent requirements limit out-of-state sources of diesel supply to California; however this is typically not a concern because California produces more diesel fuel than is consumed in the state.

Most transportation fuels consumed in PADD 5 must also comply with the federal Renewable Fuels Standard (RFS). Some PADD 5 state programs also encourage the use of renewable fuels. California's Low Carbon Fuel Standard (LCFS) is designed to reduce by 10% the average lifecycle carbon intensity of the motor gasoline and diesel transportation fuel pool, including all petroleum and nonpetroleum components, sold for consumption in California from 2012 to 2020. The lifecycle carbon intensity of a fuel is a measure of greenhouse gas emissions associated with producing and consuming the fuel. The Oregon Renewable Fuel Standard that was adopted in 2005 set a requirement for B5 biodiesel, which requires a minimum 5% biodiesel blending level in diesel fuel.

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[6] CARB diesel requires lower aromatic hydrocarbon content and a higher cetane number. Aromatic hydrocarbons are a class of chemical substances characterized by having molecular structures called benzene rings. Cetane number is an indicator of the combustion speed of diesel fuel.

The three renewable fuels used in transportation fuels are ethanol, biodiesel, and renewable diesel.[7] PADD 5 ethanol plants had a total nameplate production capacity of 510 million gallons per year (gal/y) in 2015. Ethanol is also supplied to mainland PADD 5 states from the Midwest by rail and to Hawaii from the West Coast by tanker. Sugarcane ethanol, which has lower carbon intensity than corn ethanol, is imported into PADD 5 from Brazil and the Caribbean, when economic. Use of sugarcane ethanol is driven by California's LCFS.

Biodiesel production capacity is concentrated in Washington with 107 million gal/y. Total PADD 5 biodiesel production capacity was 191 million gal/y in 2015. Imports are the principal source of renewable diesel, primarily from Asia.

Table 3. Ethanol producers and production by state

State	Number of producers	Nameplate production capacity (million gallons per year)
Alaska	—	—
Arizona	1	275
California	5	200
Hawaii	—	—
Nevada	—	—
Oregon	1	35
Washington	—	—
Total PADD 5	**7**	**510**

— = No data reported.
Nameplate capacity: volume of denatured fuel ethanol that can be produced during a period of 12 months under normal operating conditions.
Number of producers is a count of plants with operable capacity as of January 1, 2015.
Source: U.S. Energy Information Administration, Form EIA-819 Monthly Oxygenate Report

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[7] Biodiesel refers to fatty acid methyl esters produced by a chemical reaction between vegetable oils or animal fats and alcohol (transesterification), and is most commonly blended with petroleum diesel in up to 5% by volume or 20% by volume (B5 and B20). Renewable diesel refers to a diesel-like fuel that is compatible with existing infrastructure and in existing engines in any blending proportion. It is produced by refining vegetable oils or animal fats using a hydrotreating process.

Table 4. Biodiesel producers and capacity by state

State	Number of producers	Annual production capacity (million gallons per year)
Alaska	1	0
Arizona	1	2
California	7	59
Hawaii	1	6
Nevada	—	—
Oregon	1	17
Washington	3	107
Total PADD 5	**14**	**191**

—= No data reported.
Number of producers is a count of plants with operable capacity as of June 2015.
Source: U.S. Energy Information Administration, Form EIA-22M Monthly Biodiesel Production Survey

Market structure

The PADD 5 market for gasoline is both large and complex. The number of different gasoline specifications, the uniqueness of the specifications, the close balance between in-region supply and demand, and the relative price inelasticity of gasoline demand combine to create a volatile market.[8]

The gasoline market includes four separate but interrelated markets:

- **The spot market,** where sizeable volumes, typically parcels of at least 1 million gallons, are sold at the refinery gate or from imported cargoes, and delivered into a specified pipeline or storage facility, as agreed by the buyer and seller. There are about 15 to 20 participants in the West Coast spot market, including refiners that buy and sell products to balance refinery production and sales commitments, trading companies that are in the business of buying and selling gasoline but that typically have no presence in wholesale or retail gasoline markets, brokers with market knowledge and understanding that identify buyers and sellers and arrange deals, and independent retail marketers that move large volumes of gasoline through their own retail outlets. Prices in the spot market move with perceived changes in refinery supply and demand. There are three major spot markets for gasoline in PADD 5, located in the major refining centers of Los Angeles, San Francisco, and the Pacific Northwest. Prices in these markets reflect regional supply/demand balances as well as the cost to move product between the markets and product quality differences.
- **The rack market**, where wholesale buyers such as independent retailers or distributors that operate their own trucks purchase product delivered into a tank truck at a truck loading rack located at a storage and distribution terminal or refinery. Rack market participants may buy branded products that will be sold at a retail outlet under the name of a major oil company or may alternatively purchase unbranded products destined for sale at independent service stations or for use by commercial/industrial consumers. Branded and unbranded rack pricing varies.

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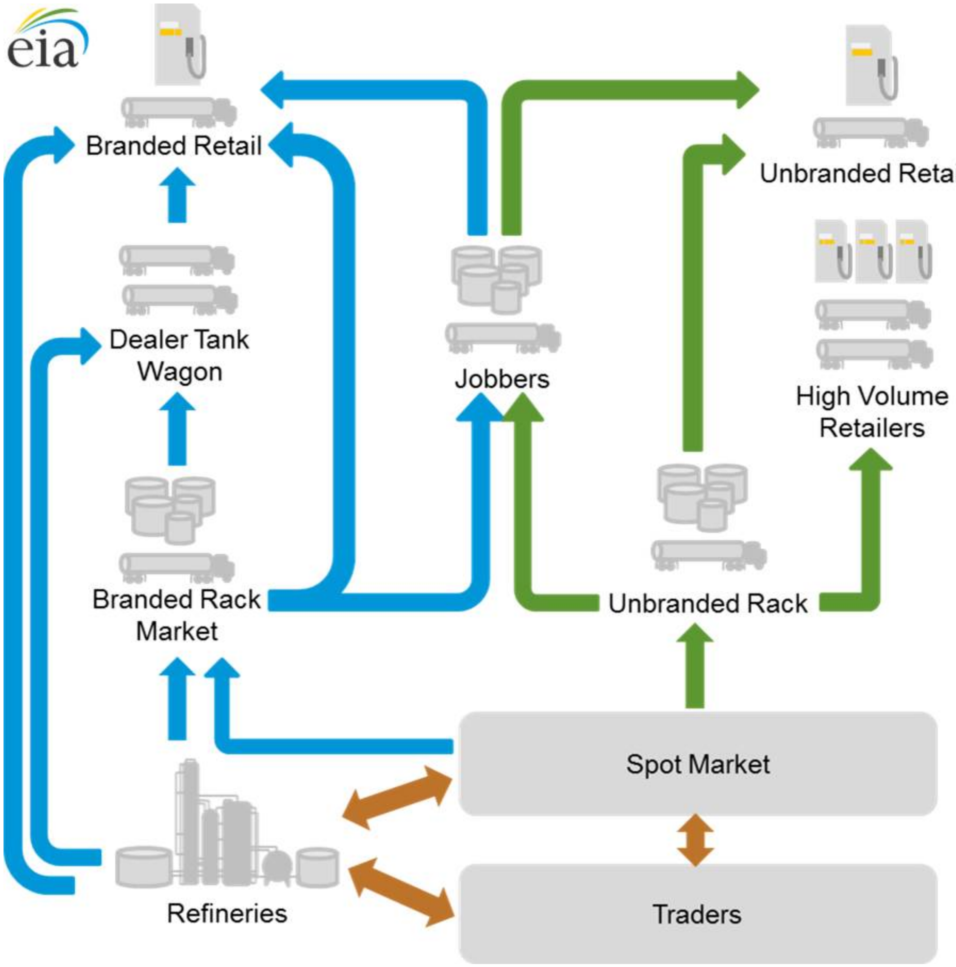
[8] Updated from Stillwater Associates. *California Strategic Fuels Reserve – Consultant Report to the California Energy Commission.* July 2002. http://www.energy.ca.gov/reports/2002-03-11_600-02-004CR.PDF

- **The dealer tank wagon (DTW) market**, where branded retail outlets (dealers) purchase branded gasoline that is delivered by tank truck (tank wagon) to their retail outlets. The price of the gasoline reflects the cost of the product and the cost of delivery.
- **The retail market**, where gasoline is sold to the end consumer at the pump at a gas station or other retail outlet. Retailers typically set prices by comparison to prices at other retail outlets. However, high volume retailers (HVRs), such as large chain stores, or *big box* store, that are focused on selling large volumes of gasoline at low margins, tend to price gasoline based on cost plus the desired margin, rather than based on prices at other retail outlets.

Figure 7. Gasoline market structure



Source: U.S. Energy Information Administration, California Strategic Reserve Study[9]

Over the past 10 years, the PADD 5 gasoline market has changed. The number of spot market participants has decreased as refinery ownership consolidation and as increased reliance on in-region refinery production of gasoline has reduced opportunities for trading companies and brokers to

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[9] Stillwater Associates. *California Strategic Reserve Study – Consultant Report.* March 10, 2002. http://www.energy.ca.gov/reports/2002-03-11_600-02-004CR.PDF.

participate in the market. Most integrated refiner-marketers have divested their retail chains, and many of the new retail operators, including hypermarkets and big box retailers, now purchase gasoline at an unbranded rack price.

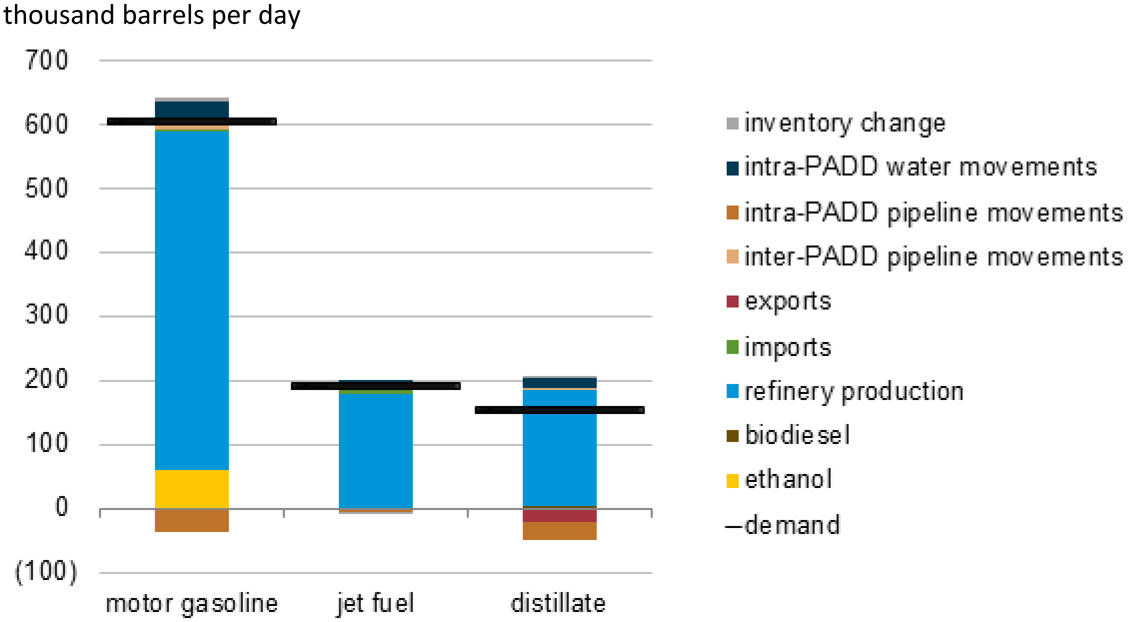
The PADD 5 market structure, notably the region's geographic isolation, unique product specifications that have increased reliance on in-region refinery production, and infrastructure limitations, can restrict both short-term and long-term responses to supply shortfalls, such as those resulting from supply chain disruptions, like refinery outages. Short-term measures to increase product supply typically include withdrawals from inventory, when available, and waterborne shipment of increased production from refineries in the region that have spare processing capacity. However, the range of product specifications across PADD 5 can make it difficult to translate inventory to other regions, and not all product specifications can be produced at all refineries. In addition, the availability of the coastwise-compliant marine vessels that are required to move fuels within the region can make it difficult to move product to where it is needed. Longer-term solutions to supply disruptions include imports from Asia and Canada as well as transfers from other U.S. refining centers like the Gulf Coast; however, only a limited number of refineries outside PADD 5, both inside and outside the United States, can manufacture product to meet all PADD 5 specifications, notably the CARB gasoline and CARB diesel specifications. As a result, when PADD 5 transportation fuel supply is disrupted, wholesale and retail prices often increase more than would be expected in other regions, like the Gulf Coast and East Coast, where alternative sources of supply are closer and more readily available, and thus lower cost.

Southern California and Southern Nevada

The Southern California and Southern Nevada (SCSN) region includes the southernmost counties of California[10] as well as the Las Vegas, Nevada metropolitan area of Southern Nevada. The region accounts for more than 40% of total PADD 5 motor gasoline demand, the largest share of motor gasoline demand of the six regional PADD 5 markets, and about 7% of total U.S. demand. Because of the many military air bases and large commercial aviation hubs, jet fuel demand in the SCSN region accounts for about 45% of total PADD 5 jet fuel demand and 14% of U.S. demand. SCSN accounts for 32% of total PADD 5 distillate fuel demand, which is about 4% of U.S. demand.

A combination of in-region refinery production, marine-delivered fuels produced at refineries in Northern California and Washington State, receipts of fuels produced at refineries in other PADDs, and imports from the global market supply the SCSN region with transportation fuels. The regional refineries do not produce sufficient gasoline or jet fuel to meet in-region demand, but they do produce more distillate than is consumed in the region. In-region refinery production is supplemented with marine deliveries of product from refineries in Northern California and Washington State as well as imports from the global market. Transportation fuels produced at SCSN refineries also supply Arizona and some are exported into the global market. Exports are primarily distillate fuel, which may not meet in-region specifications.

Figure 8. Southern California and Southern Nevada 2013 supply/demand balances



Note: All movements are on a net basis.
Source: Stillwater Associates analysis of EIA data

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[10] The southernmost counties of California are Imperial, Kern, Los Angeles, Orange, Riverside, San Bernardino, San Diego, San Luis Obispo, Santa Barbara, and Ventura.

Supply and logistics

There are eight operating refineries in the Southern California and Southern Nevada region, and these refineries supply most of the motor gasoline, jet fuel, and distillate consumed in the region. The refineries have combined atmospheric crude distillation unit capacity of 1,019,100 barrels per calendar day.[11] All eight refineries are located in the Los Angeles metropolitan area.

Table 4. Southern California and Southern Nevada refineries

Company	Location	Atmospheric Crude Distillation Unit (ACDU) operating capacity b/cd	Markets served
Valero Asphalt	Wilmington	6,300	
Lunday Thagard	Southgate	8,500	local
Valero	Wilmington	85,000	Southern California (S. CA), Las Vegas, Phoenix
Tesoro	Wilmington	104,500	S. CA, Las Vegas
Phillips 66	Wilmington	139,000	S. CA, Las Vegas
ExxonMobil	Torrance	149,500	S. CA
Tesoro	Carson	257,300	S. CA, Las Vegas
Chevron	El Segundo	269,000	S. CA, Las Vegas, Phoenix

Source: Stillwater Associates analysis of EIA data

In 2013, SCSN refineries produced a total of 526,800 b/d of gasoline, 182,500 b/d of distillate, and 178,100 b/d of jet fuel. This production was sufficient to supply 87% of regional motor gasoline demand (96% when blended with ethanol), 117% of distillate fuel demand, and 92% of jet fuel demand.

Production from the refineries moves primarily by pipeline from the Los Angeles area to bulk storage and distribution terminals throughout the SCSN region (Figure 9). From terminals, product moves by tank truck to retail outlets. Product from the Los Angeles area also supplies the Arizona Region (Arizona) by pipeline. The Kinder Morgan West Line, which is owned and operated by Kinder Morgan, Inc., originates in the Los Angeles Basin, and in 2013, it moved 35,000 b/d of gasoline, 6,000 b/d of jet, and 28,000 b/d of distillate to Phoenix, Arizona. This supply reduces the availability of product to supply the SCSN region, which is especially important for motor gasoline.

Transportation fuels produced at refineries in Salt Lake City, Utah, in PADD 4, also supply SCSN. The UNEV Pipeline[12] runs from Salt Lake City, Utah to North Las Vegas, Nevada and in 2013 moved 9,000 b/d of gasoline and 1,000 b/d of distillate to Las Vegas.

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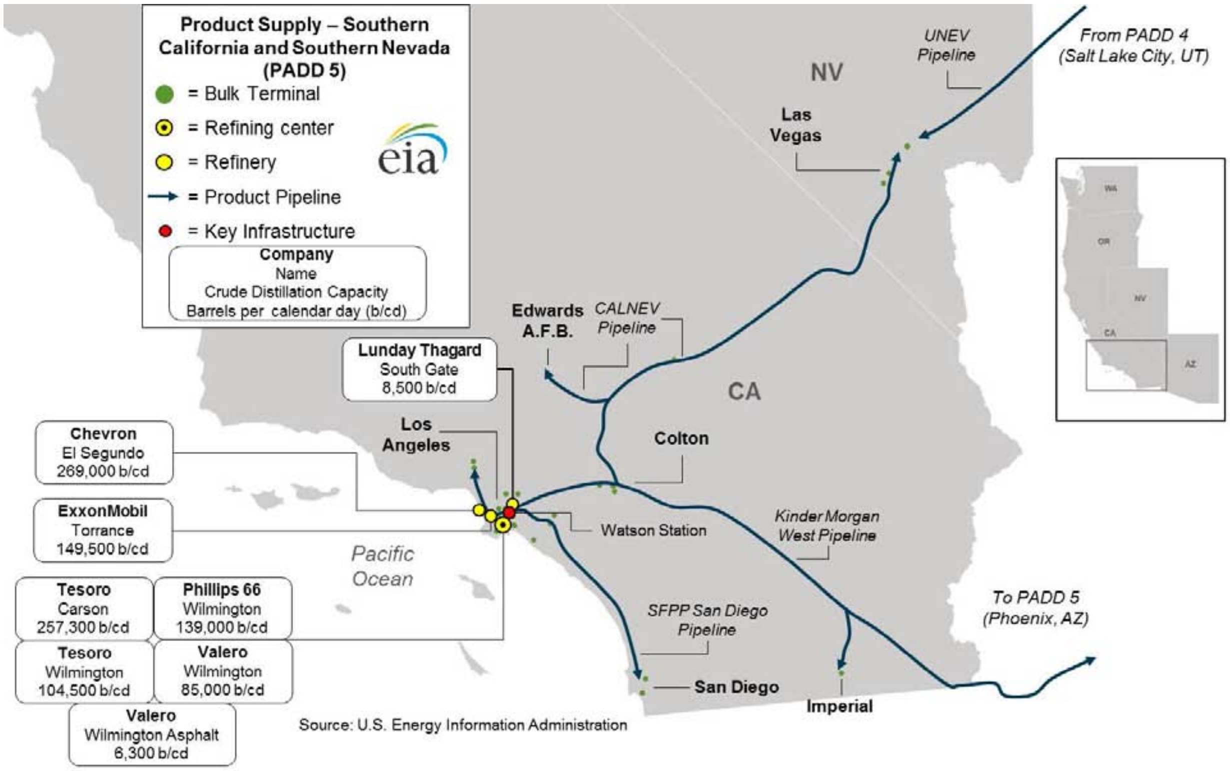
[11] Barrels per calendar day is a measure of the amount of input that a distillation unit can process in a 24-hour period under usual operating conditions. It takes into account both planned and unplanned maintenance. Barrels per stream day, another measure of refinery capacity, is the maximum number of barrels of input that a distillation facility can process within a 24-hour period when running at full capacity under optimal crude and product slate conditions with no allowance for downtime. Stream day capacity is typically about 6% higher than calendar day capacity.

[12] UNEV Pipeline, LLC is a joint venture between a subsidiary of Holly Energy Partners, L.P. and Sinclair Transportation Company.

Figure 9. Southern California and Southern Nevada refineries and petroleum product flows



Source: U.S. Energy Information Administration

Most of the major product distribution pipelines in the SCSN region can move product to and from more than one refinery and more than one terminal, which provides flexibility in sourcing product and ensuring that product is available for distribution to retail outlets. However, in the Los Angeles metropolitan area, there are large bulk storage and distribution terminals that are part of closed systems supplied by a single refinery. Disruptions to these closed systems can require changes to the pattern of product distribution from the terminal to the retail outlet, which can lengthen supply times and increase supply costs.

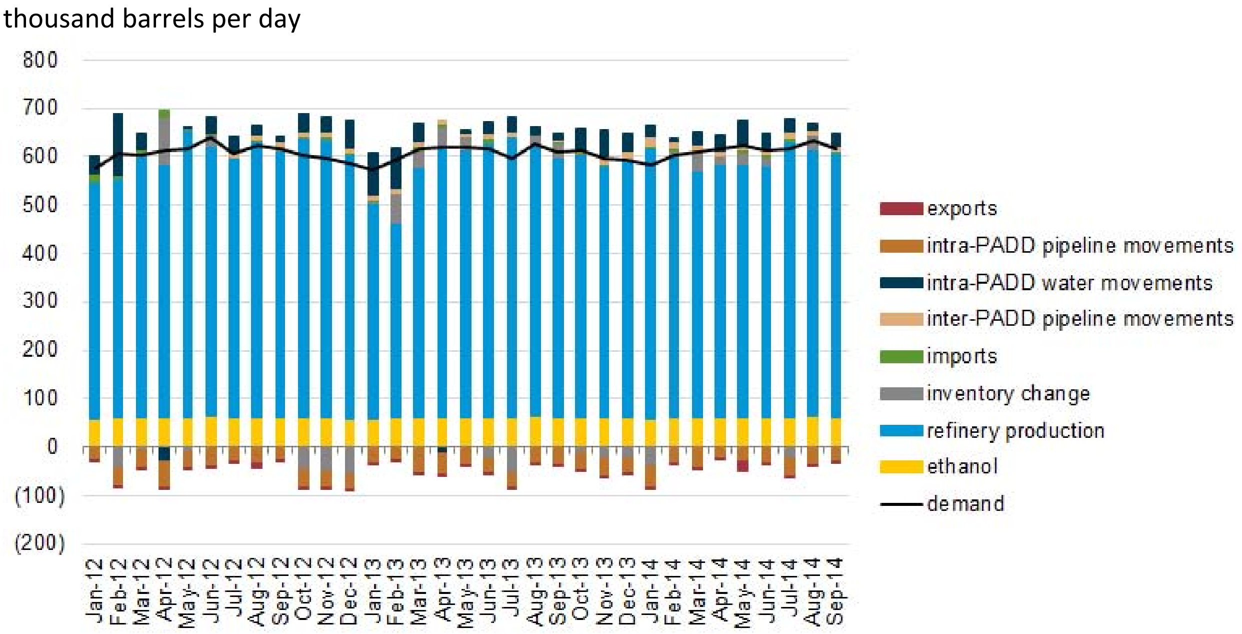
Refineries, pipelines, ports, and storage facilities are all critical to the effective functioning of the petroleum supply chain. However, in the SCSN region, Watson Station, a pipeline hub in Carson, California, is particularly important. Product from many of the region's refineries must move through Watson Station to reach bulk storage and distribution facilities. Power outages and earthquakes can affect the region’s infrastructure.

Motor gasoline supply/demand

SCSN refineries produced sufficient gasoline to supply about 87% of in-region motor gasoline demand (96% when blended with ethanol) in 2013, although a portion of that gasoline was used to supply the Arizona region. Gasoline supplied from refineries in Northern California and Washington State and shipped by marine vessel and imports from the global market provided additional supply. Historically, the SCSN region has imported small quantities of gasoline, including gasoline-blending components, primarily from Canada and Asia. However, since March 2015, because of the continuing outage of gasoline-producing units at the Torrance refinery, gasoline imports have increased substantially. Several weeks after the Torrance, California, outage, West Coast gasoline imports more than tripled, and averaged 81,000 b/d from March 27 through June 26. Monthly data through April 2015 show California total gasoline imports coming from South Korea, Singapore, and Taiwan in Asia as well as Sweden, the United Kingdom, Italy, and the Netherlands in Europe. During periods of unplanned refinery outages and other in-region supply disruptions, waterborne supply of gasoline from other PADD 5 regions like Northern California and the Pacific Northwest, other PADDs, and the global market is critical. The availability of product from other PADD 5 regions and other PADDs depends on the availability of coastwise-compliant marine vessels.

The SCSN region exported small volumes of gasoline to Central and South America in 2013, some of which likely did not meet CARB gasoline specifications, and the region continues to supply Arizona via intra-PADD pipeline, about 36,000 b/d.

Figure 10. Southern California and Southern Nevada motor gasoline supply/demand balance

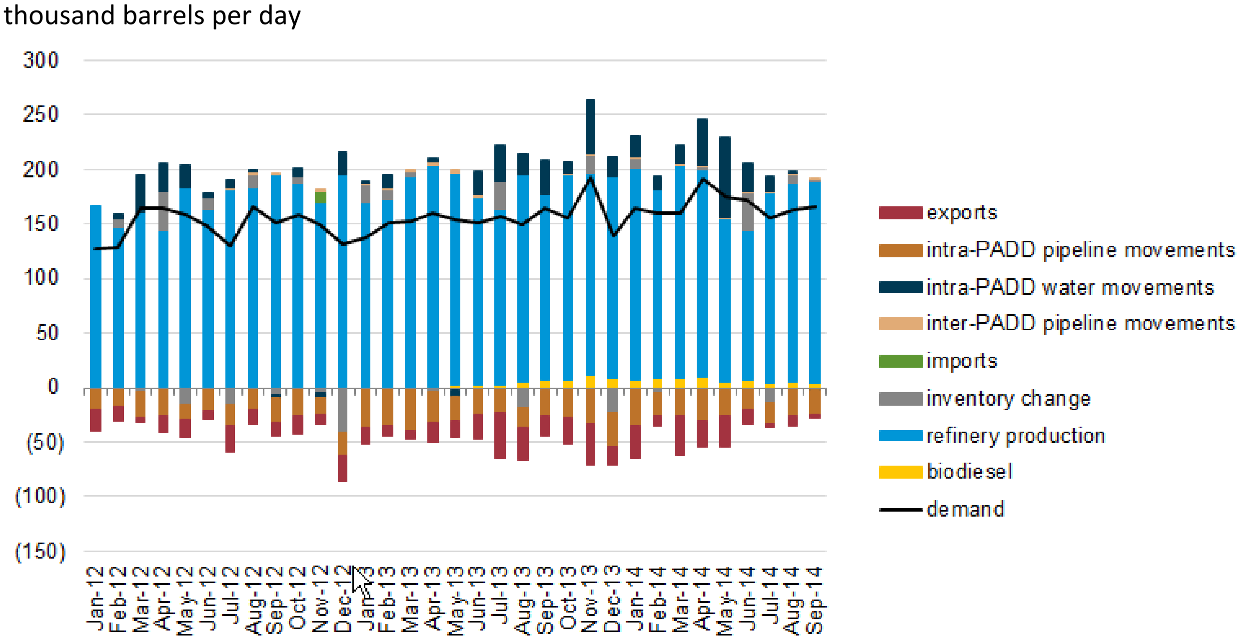


Note: All movements are on a net basis.
Source: Stillwater Associates analysis of EIA data

Distillate fuel supply/demand

Refineries in the SCSN region produce substantially more distillate fuel than is consumed in the region, 17% more in 2013. The region also receives distillate fuel by marine vessel from other sub-PADD 5 regions, 16,000 b/d in 2013, and by pipeline into Las Vegas from PADD 4, 1,200 b/d in 2013. Some of the receipts from within PADD 5 are likely to balance supply/demand of CARB specification diesel, especially during periods of SCSN refinery maintenance. The region also supplies distillate fuel to Arizona, 28,200 b/d in 2013, and exports distillate fuel to Mexico as well as to Central America and South America, about 21,500 b/d in 2013. In Arizona, diesel fuel is required to meet the standard ultra-low sulfur diesel specification, which is less stringent than the CARB diesel specification. As a result, Arizona is an outlet for Southern California diesel production that does not meet CARB specifications. Exports of distillate fuel may also include product that does not meet CARB diesel specifications.

Figure 11. Southern California and Southern Nevada distillate supply/demand balance



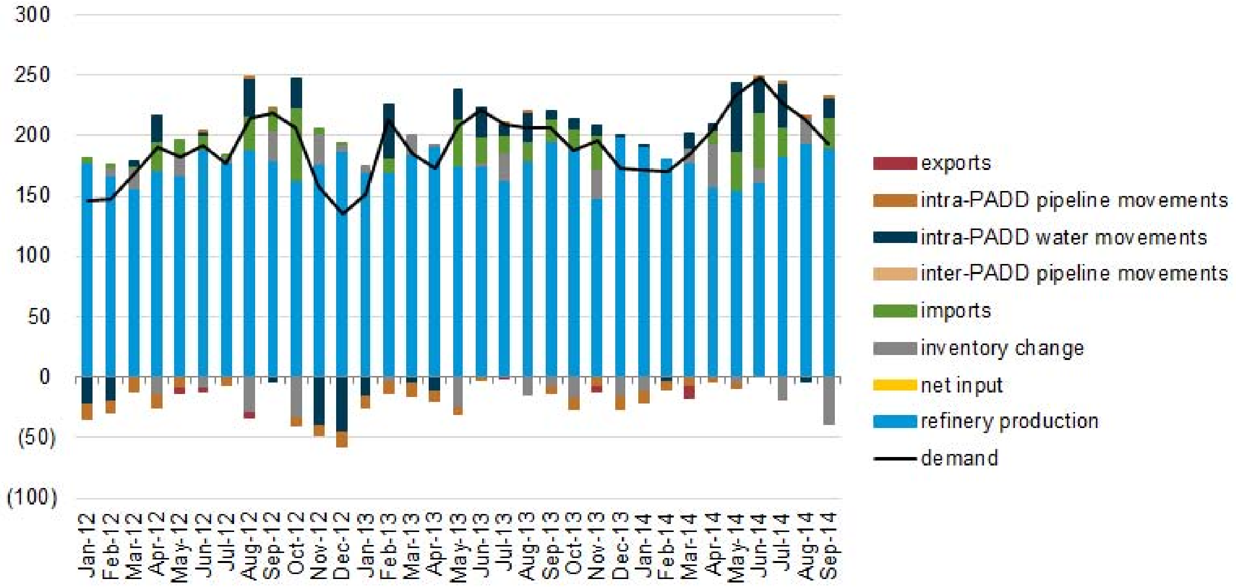
Note: All movements are on a net basis.
Source: Stillwater Associates analysis of EIA data

Jet fuel supply/demand

Refineries in the Southern California/Southern Nevada region do not produce sufficient jet fuel to meet in-region demand. In-region refinery production is supplemented with imports and transfers from other regions within PADD 5. The SCSN region also supplies jet fuel to Arizona by pipeline. In 2013, in-region refineries produced jet fuel sufficient to supply 92% of in-region demand. Imports and receipts from other regions of PADD 5 supplied the balance. The region typically imports more jet fuel than either motor gasoline or distillate, and imports are principally from refineries in Asia. Demand patterns for jet fuel are more variable than for gasoline and distillate, and as a result, the region can be caught short if demand rises unexpectedly or if in-region supplies are disrupted. Pipeline flows of jet fuel to Arizona have declined to an average of 6,000 b/d in 2013 as PADD 3 refineries supply increasing volumes to Arizona.

Figure 12. Southern California and Southern Nevada jet fuel supply/demand balance

thousand barrels per day



Note: All movements are on a net basis.
Source: Stillwater Associates analysis of EIA data

Renewable fuels and biofuels supply/demand

The region's demand for biofuels is driven by California's Low Carbon Fuel Standard (LCFS), which creates demand for fuels with lower carbon intensity, including low carbon-intensity corn-based ethanol and sugar-based ethanol, biodiesel, and renewable diesel.

Ethanol blending is limited to 10% by the CARB specification for motor gasoline, which is reflected in ethanol's 10% share of gasoline demand. Ethanol supply is from a combination of imported sugar-based ethanol and receipts from PADD 2 (Midwest) delivered by rail and truck to blending terminals.

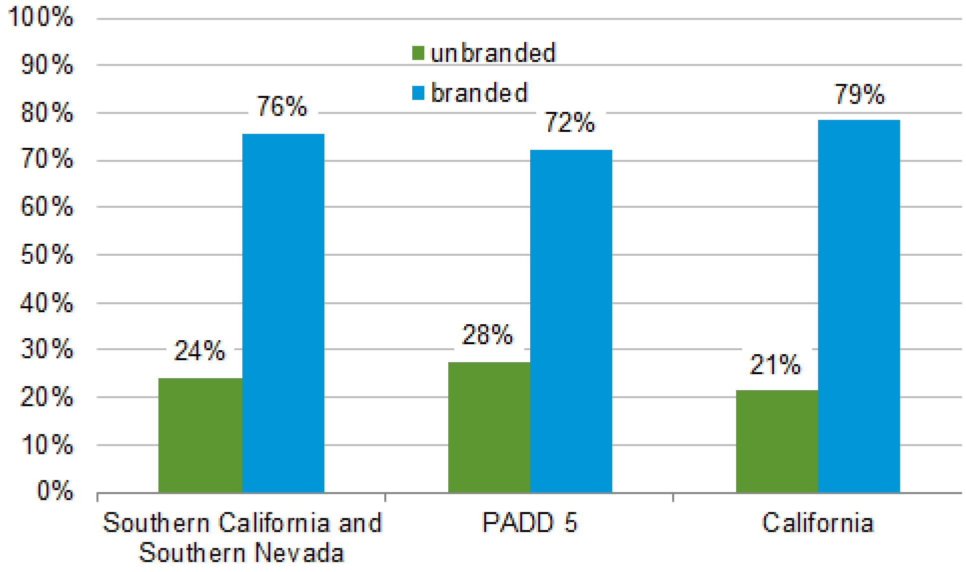
Biodiesel and renewable diesel supplied 2% of the region's distillate demand in 2013 and 4% in the first nine months of 2014. Biodiesel and renewable diesel supply is from a combination of PADD 5 production, receipts from other PADDs, and imports.

Retail markets

There are about 27 distinct branded and unbranded companies participating in the retail market for gasoline and distillate fuel in the Southern California and Southern Nevada region. About 76% of retail outlets are branded, meaning that they are associated with and display a major oil company brand, like Chevron, Shell, 76, Valero, and ARCO. The remaining 24% of retailers are referred to as unbranded because they are not affiliated with a major oil company brand. Unbranded retailers include small independent retailers as well as big box retailers. In California as a whole, 79% of retail outlets are associated with a major brand, while 21% are unbranded. The sale of BP's Southern California business to Tesoro in 2012 resulted in the most recent large-scale shift in the region's retail market structure.

Figure 13. Southern California and Southern Nevada retail market structure

percent of retail outlets



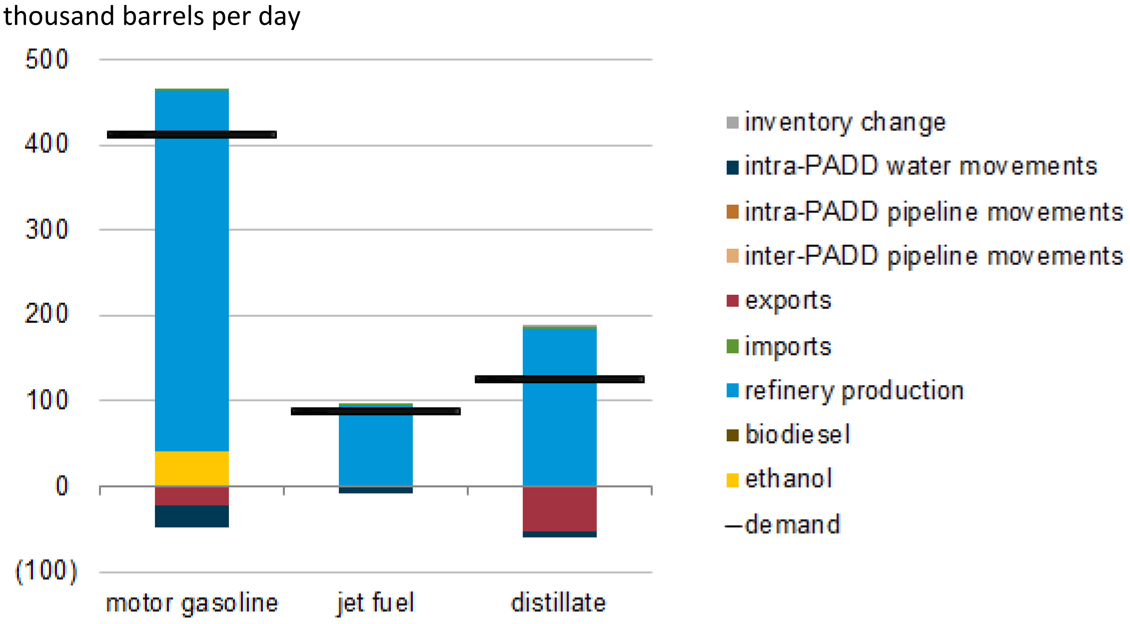
Source: Stillwater Associates analysis of Oil Price Information Service (OPIS) data for the week of December 31, 2014
Note: OPIS data are survey rather than census data, and survey data include transactions from large commercial trucking fleet customers using company credit cards and not from cash or credit card sales to the general public.

Northern California and Northern Nevada

The Northern California and Northern Nevada region (NCNN) includes counties in California north of San Luis Obispo, Kern, and San Bernardino counties, and in Nevada north of Las Vegas. In 2013, with average motor gasoline demand of 412,000 b/d, the region accounted for 27% of total PADD 5 motor gasoline demand and 4.7% of U.S. motor gasoline demand. NCNN distillate demand of 125,000 b/d in 2013 accounted for 25% of PADD demand and 3% of U.S. demand. NCNN jet fuel demand averaged 88,000 b/d in 2013, 21% of PADD demand and 6% of U.S. demand.

The region is supplied by in-region refinery production and refineries in the region produce more motor gasoline, jet fuel, and distillate fuel than is consumed in the region. As a result, NCNN supplies other regional markets in PADD 5, primarily Southern California and Southern Nevada, with motor gasoline, jet fuel, and diesel fuel, and also exports these products. In 2013, the region exported 22,100 b/d of gasoline, 2,300 b/d of jet fuel, and 52,400 b/d of distillate fuel, primarily to Central and South America.

Figure 14. Northern California and Northern Nevada 2013 supply/demand balance



Note: All movements are on a net basis.
Source: Stillwater Associates analysis of EIA data

Supply and logistics

There are nine operating refineries in two primary refining centers in the Northern California and Northern Nevada region with combined atmospheric crude distillation unit capacity of about 885,000 barrels per calendar day. Only one of the refineries is located outside California, in Nevada. The sole refinery in Nevada, Foreland Refining in Ely, produces asphalt and fuel oil rather than motor gasoline, distillate fuel, and jet fuel. Most of the California refining capacity in the NCNN region is in the San Francisco Bay area. Several smaller refineries are located in California's Central Valley.

Table 5. Northern California and Northern Nevada refineries

Company	Location	Atmospheric Crude Distillation Unit (ACDU) operating capacity b/cd	Markets served
Chevron	Richmond	245,271	Northern California (N. CA), Reno, Oregon
Tesoro	Martinez	166,000	N. CA, Reno
Shell	Martinez	156,400	N.CA, Los Angeles, Reno, Nevada, exports
Valero	Benicia	145,000	N.CA, Reno, Nevada, exports
Phillips 66[1]	Rodeo	120,200	S. CA, Las Vegas
Kern Oil & Refining	Bakersfield	26,000	Central California
San Joaquin Refining	Bakersfield	15,000	Central California
Santa Maria Refinery	Santa Maria	9,500	local
Foreland Refining	Ely, Nevada	2,000	local

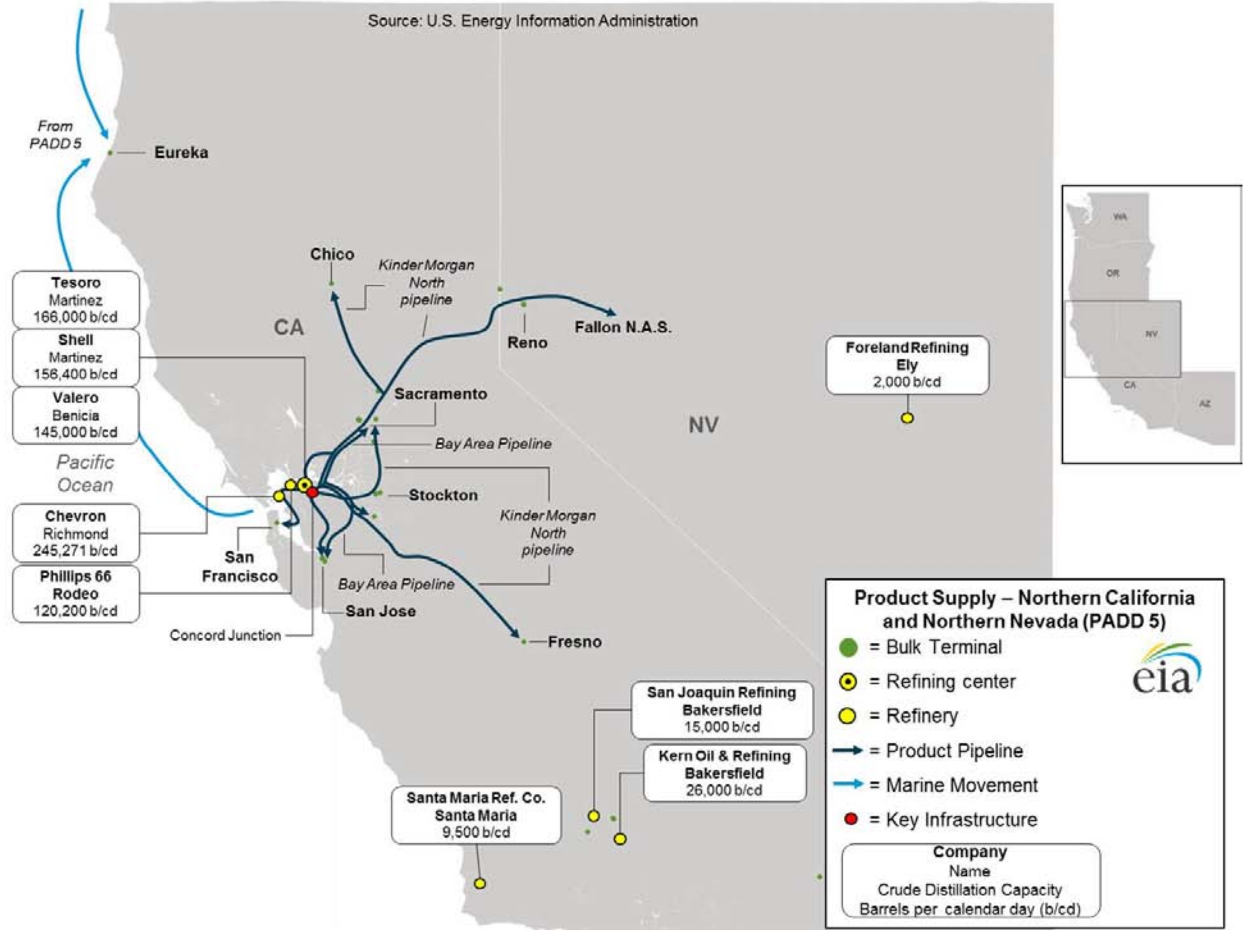
[1] A portion of this facility is actually located in San Luis Obispo County but is operated as part of the Rodeo refinery.
Source: Stillwater Associates analysis of EIA data

In 2013, NCNN refineries produced an average of 421,000 b/d of gasoline blending components and finished motor gasoline, 185,000 b/d of distillate, and 96,000 b/d of jet fuel. This production was more than sufficient to meet in-region demand. NCNN refineries produced product sufficient to meet 102% of regional demand for finished motor gasoline (112% when blended with ethanol), 108% of jet fuel demand, and 147% of diesel fuel demand. Production from refineries in Northern California regularly supplies parts of Southern California and Oregon by marine vessel.

Product is shipped by pipeline from the refineries in San Francisco to storage and distribution terminals in the San Francisco area and to terminals further inland in Fresno and Chico, California, and also in Nevada. The large regional product distribution pipelines are owned and operated as common carrier pipelines by Kinder Morgan, Inc. No pipelines connect the NCNN region to other PADDs or other PADD 5 regional markets, and, as a result, supply from NCNN to those areas moves by marine vessel. The major port facilities through which product is exported into the global market and from which product is shipped to other regional markets in PADD 5 are located on the San Francisco Bay.

Critical supply chain infrastructure includes the refineries, pipelines, ports, and storage facilities of the San Francisco Bay area. In particular, the Concord pipeline junction is the gathering and entry point for the Kinder Morgan pipeline system, the main distribution artery for the region. Power outages and earthquakes can affect the region’s infrastructure, and heavy fog can disrupt the port facilities within the San Francisco Bay.

Figure 15. Northern California and Northern Nevada refineries and petroleum product flows

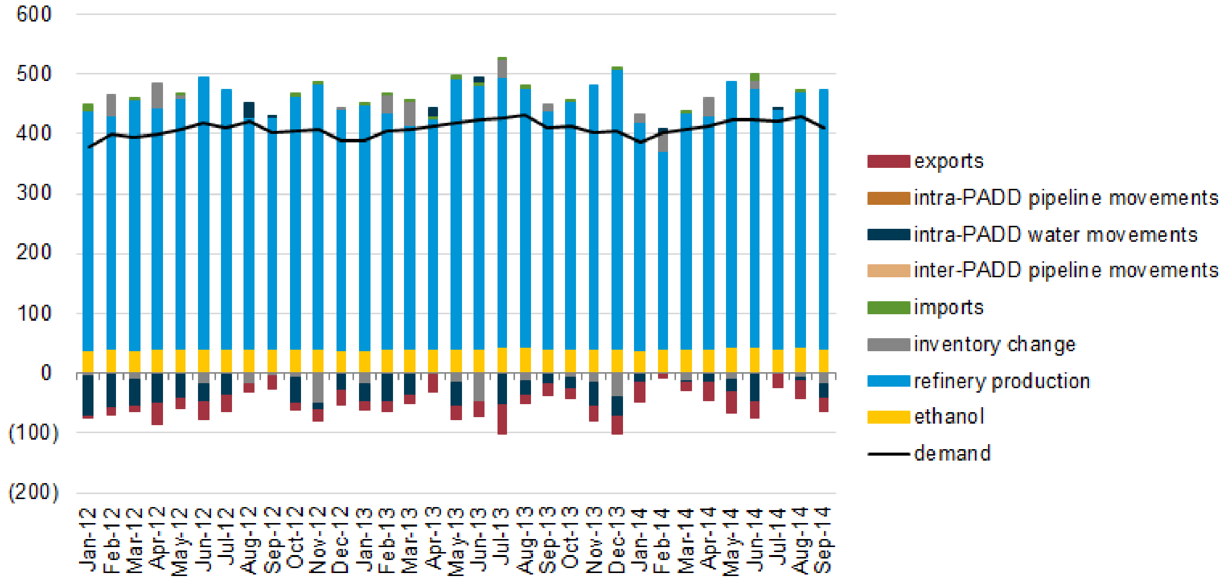


Motor gasoline supply/demand

In 2013, NCNN refineries produced an average of 421,000 b/d of motor gasoline blending components that when blended with ethanol was sufficient to supply about 112% of 2013 finished gasoline demand. Without pipeline interconnections to other regional markets in PADD 5, surplus gasoline must be shipped out of the region by marine vessel. In 2013, the NCNN region supplied about 26,900 b/d to other PADD 5 regional markets, primarily Southern California but also Reno, Nevada, and exported 22,100 b/d into the global market, principally supplying Latin America.

Figure 16. Northern California and Northern Nevada motor gasoline supply/demand balance

thousand barrels per day

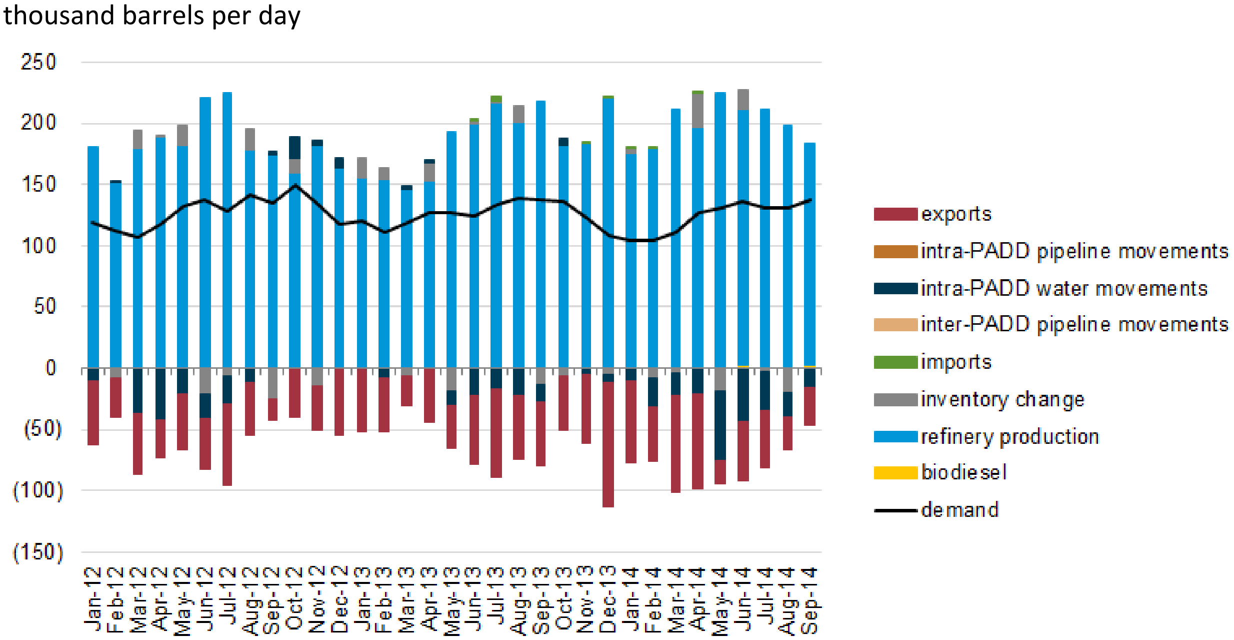


Note: All movements are on a net basis.
Source: Stillwater Associates analysis of EIA data

Distillate fuel supply/demand

In 2013, NCNN refineries produced an average of 185,000 b/d of distillate fuel, which when blended with biodiesel was sufficient to supply about 147% of finished distillate fuel demand. Without pipeline interconnections to other regional markets in PADD 5, surplus distillate fuel must be shipped out of the region by marine vessel. In 2013, the region transferred 8,200 b/d to other regional markets in PADD 5 and exported 52,400 b/d of distillate, mostly to Central America and South America, principally to Mexico. Because the region produces substantially more diesel fuel than is needed to meet local demand, NCNN has become an important source of diesel fuel for other regions within PADD 5 as well as the Pacific basin.

Figure 17. Northern California and Northern Nevada distillate supply/demand balance



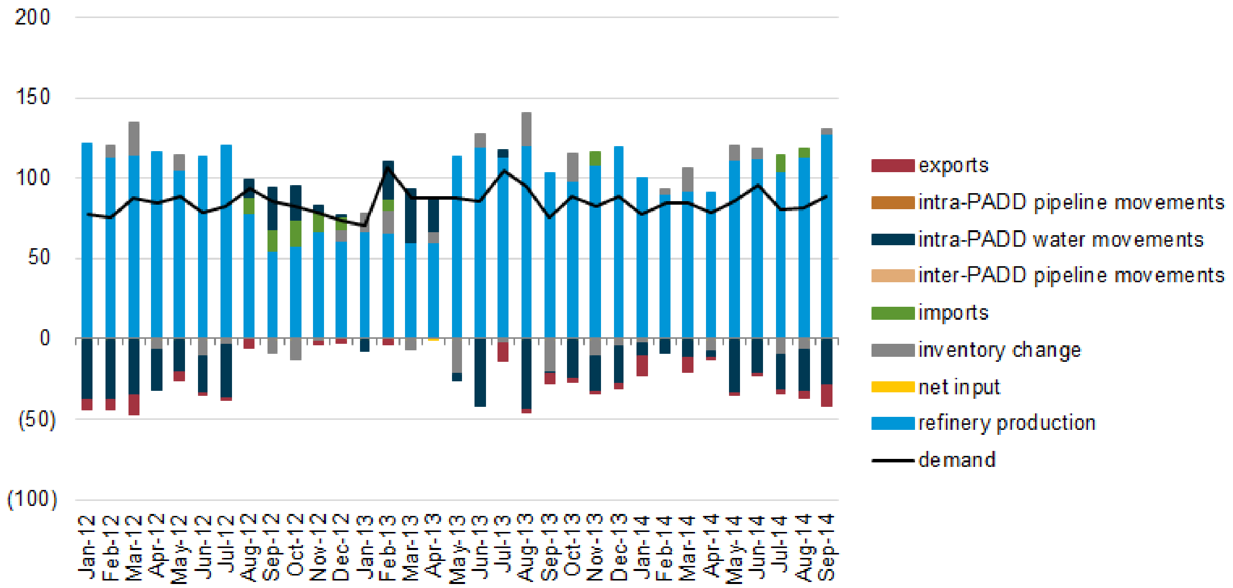
Note: All movements are on a net basis.
Source: Stillwater Associates analysis of EIA data

Jet fuel supply/demand

The Northern California and Northern Nevada region produces more jet fuel than is consumed in the region, albeit by a much narrower margin than distillate fuel, with in-region refineries producing about 96,000 b/d on average in 2013, 108% of regional demand. The region has also imported small volumes of jet fuel, likely to balance the timing of supply and demand and/or to take advantage of economic supply opportunities. Refinery production beyond that needed to meet in-region demand is principally shipped to other PADD 5 regional markets, but it also is exported. In 2013, about 7,200 b/d was shipped to other PADD regional markets and 2,300 b/d was exported to Canada and Latin America. The region typically produces more jet fuel than is needed to meet in-region demand. However, in the second half of 2012, following a major disruption at Chevron's Richmond refinery, NCNN shifted from producing more jet fuel than needed to meet in-region demand, to producing less. This circumstance illustrates the sensitivity of the Northern California region as well as the sensitivity of PADD 5 as a whole to refinery disruptions.

Figure 18. Northern California and Northern Nevada jet fuel supply/demand balance

thousand barrels per day



Note: All movements are on a net basis.
Source: Stillwater Associates analysis of EIA data

Renewable fuels and biofuels supply/demand

The region's demand for biofuels is driven by California's Low Carbon Fuel Standard (LCFS), which creates demand for fuels with lower carbon intensity, including low carbon-intensity corn-based ethanol and sugar-based ethanol, biodiesel, and renewable diesel.

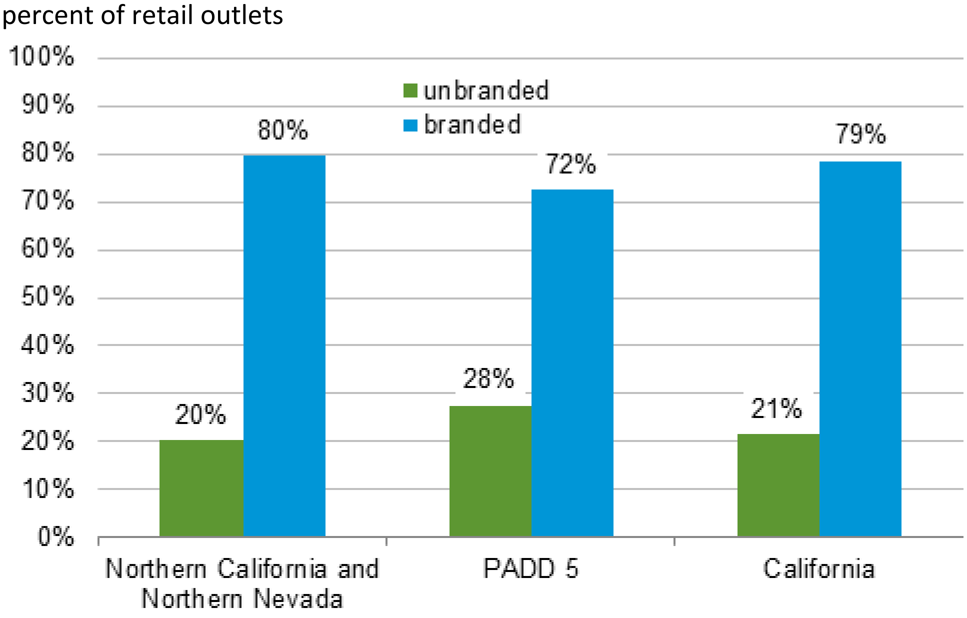
Ethanol blending is limited to 10% of the CARB specification for motor gasoline, which is reflected in ethanol's 10% share of gasoline demand. Ethanol supply is a combination of imported sugar-based ethanol and receipts from the PADD 2 (Midwest) delivered by rail and truck to blending terminals.

Biodiesel and renewable diesel supplied a very small percentage of the region's distillate demand in 2013, less than 1%. Biodiesel and renewable diesel supply is from a combination of PADD 5 production, receipts from other PADDs, and imports.

Retail markets

In the Northern California and Northern Nevada region, 80% of retail outlets are branded and 20% are unbranded. In Northern California, about 21 branded and unbranded companies participate in the retail market for gasoline and distillate fuel,[13] compared with about 12 in the Reno/Carson City, Nevada market. In Northern California, major oil company branded outlets dominate the retail sector, and the top five brands have 76% of the number of retail outlets. The Reno/Carson City market is characterized by a mix of branded and unbranded retail outlets.

Figure 19. Northern California and Northern Nevada retail market structure



Source: Stillwater Associates analysis of Oil Price Information Service (OPIS) data for the week of December 31, 2014
Note: OPIS data are survey rather than census data, and survey data include transactions from large commercial trucking fleet customers using company credit cards and not from cash or credit card sales to the general public.

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[13] Northern California counties with less than 1% of total state gasoline sales are excluded from these numbers.

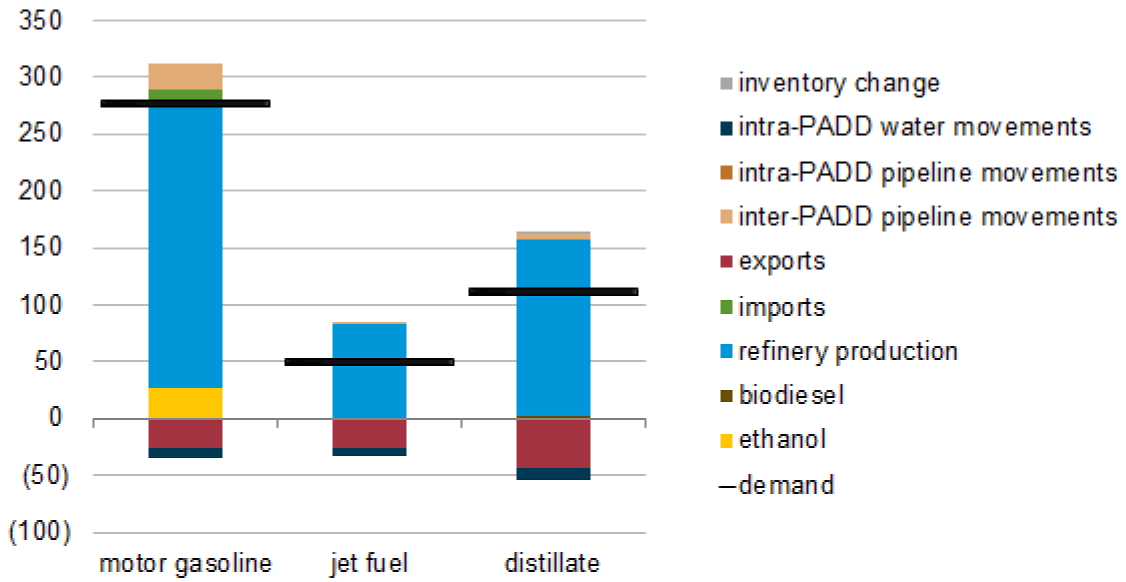
Pacific Northwest

The Pacific Northwest region (PNW) includes Oregon and Washington. In 2013, with 277,300 b/d of motor gasoline demand, the region accounted for 18% of total PADD 5 motor gasoline demand and 3% of total U.S. demand. At 111,400 b/d, PNW demand for distillate fuel was 23% of PADD 5 demand and 3% of U.S. demand. Jet fuel demand in the Pacific Northwest averaged 51,400 b/d in 2013, 12% of PADD 5 demand and 4% of U.S. demand.

The region is supplied by a combination of in-region refinery production, imports, and receipts of product manufactured at refineries in other PADDs. Refineries in the PNW produce about as much gasoline as is consumed in the region, but considerably more than enough distillate fuel and jet fuel than is needed to meet in-region demand. The region supplies distillate fuel and jet fuel to the global market and to other regions within PADD 5 and also exports motor gasoline. PNW also imports motor gasoline and a small amount of distillate. The combination of imports and exports reflects the configuration of the distribution system and gasoline grade imbalances. The PNW typically does not receive product from other regions within PADD 5. In 2013, the region exported 26,000 b/d of motor gasoline, 26,800 b/d of jet fuel, and 43,200 b/d of distillate fuel, primarily to Canada, Mexico Central America, and South America.

Figure 20. Pacific Northwest 2013 supply/demand balance

thousand barrels per day



Note: All movements are on a net basis.
Source: Stillwater Associates analysis of EIA data

Supply and logistics

There are five operating refineries in the PNW region, located in and around Puget Sound, Washington. There are no refineries in Eastern Washington or in Oregon. Historically, the PNW refineries processed a combination of Alaska North Slope crude oil, Canadian crude oil delivered by the Kinder Morgan Trans Mountain Pipeline,[14] and waterborne imports of other globally-produced crude oil. More recently, Bakken crude oil produced in the United States has been added to refinery crude slates. Bakken crude oil is delivered by railroad and has displaced both ANS and waterborne imports.

Table 6. Pacific Northwest refineries

Company	Location	Atmospheric Crude Distillation Unit (ACDU) capacity b/cd	Markets served
BP	Ferndale (Cherry Point)	225,000	Western Washington, Oregon, exports
Phillips 66	Ferndale	101,000	Western Washington, Oregon, exports
Shell	Anacortes	145,000	Western Washington, Oregon, exports
Tesoro	Anacortes	120,000	Western Washington, Oregon
U.S. Oil & Refining	Tacoma	40,700	Western Washington

Source: Stillwater Associates analysis of EIA data

In 2013, PNW refineries produced an average of 253,400 b/d of motor gasoline and motor gasoline blending components, 156,300 b/d of distillate fuel, and 83,600 b/d of jet fuel. This production was sufficient to meet 91% of regional demand for motor gasoline (102% when blended with ethanol), 163% of jet fuel demand, and 138% of distillate fuel demand. Production from refineries in Washington State regularly supplies Alaska and California.

Product is shipped from the refineries by pipeline north and south to supply Portland, Oregon and Seattle, Washington, and product is shipped by marine vessel to supply the global markets and other regions within PADD 5. Many of the Portland, Oregon storage and distribution terminals have access to the Columbia River and can ship and receive product by marine vessel. Each of the five refineries also have associated dock infrastructure for loading and discharging marine vessels, which supports imports and exports of petroleum products.

Product moves from storage and distribution terminals in Portland, Oregon south to Eugene, Oregon by pipeline. Distribution infrastructure to move product from the western portions of Washington and Oregon east is limited. The only connection between the western and eastern portions of the region is marine transport along the Columbia River, specifically between Portland, Oregon and Pasco, Washington. There is no pipeline infrastructure to move products across the Cascade Range of mountains. As a result, Eastern Washington is supplied with product from refineries in PADD 4. Product moves by pipeline from Salt Lake City, Utah into eastern Washington and Oregon and by pipeline from refineries in Billings, Montana into eastern Washington.

Critical infrastructure in the region includes the refinery complexes, pipelines, storage and distribution terminals, and the marine facilities at refineries and terminals, notably those along the Columbia River.

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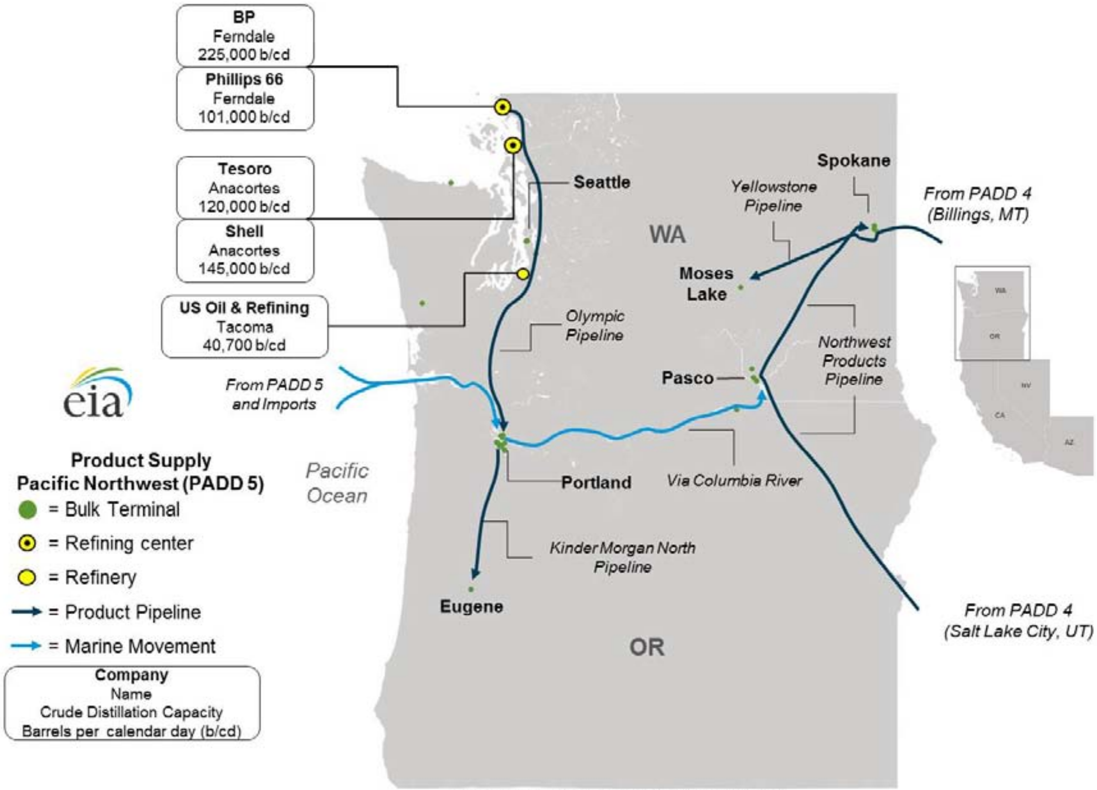
[14] The Kinder Morgan Trans Mountain Pipeline (TMPL) transports both crude oil and refined products to the west coast of Canada and the United States. TMPL moves product from Edmonton, Alberta, to marketing terminals and refineries in the central British Columbia region, the Greater Vancouver area, and the Puget Sound area in Washington state, as well as to other markets such as California, the U.S. Gulf Coast, and overseas through the Westridge marine terminal located in Burnaby, British Columbia. Only crude oil and condensates are shipped into the United States.

Weather can disrupt the region's marine facilities. The Olympic pipeline,[15] which runs from Puget Sound to Portland, Oregon and is connected to four of the five PNW refineries, is the main north-south corridor for petroleum product transportation in the PNW region. Disruptions to flows on the Olympic pipeline can have a major impact on regional supply. Many of the storage and distribution terminals connected to the pipeline lack other supply options. As a result, during supply disruptions, product typically supplied from these terminals may need to be sourced from other terminals, which can increase supply costs and therefore prices.

Figure 21. Pacific Northwest refineries and petroleum product flows



Source: U.S. Energy Information Administration

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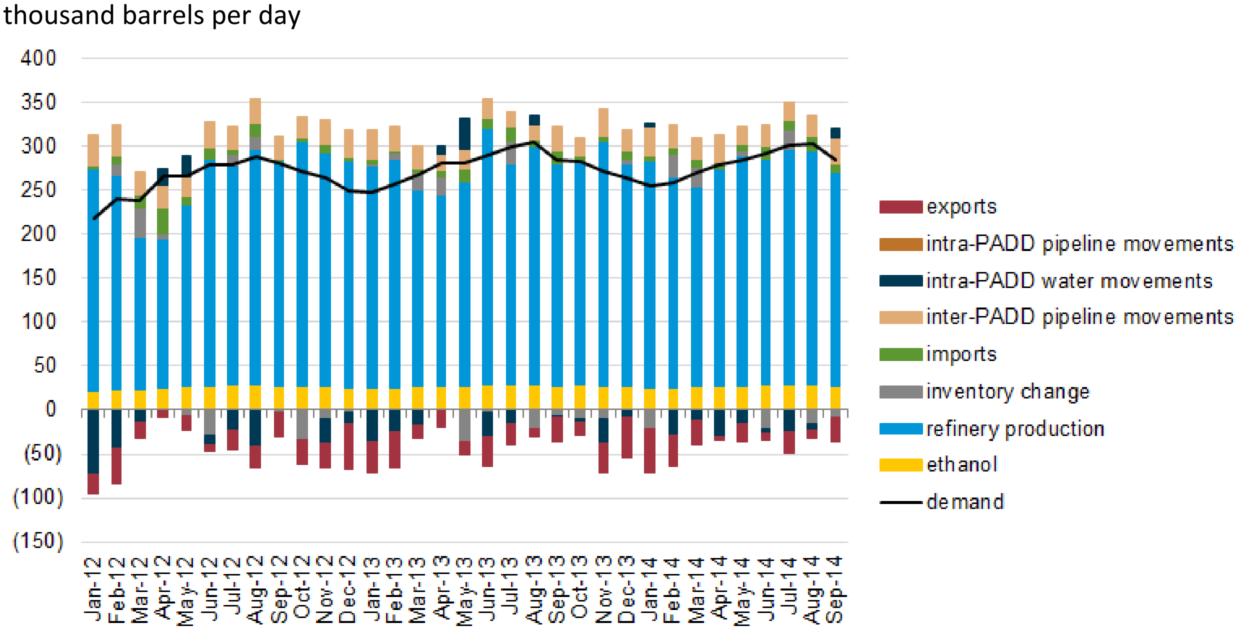
[15] The pipeline runs along a 299 mile corridor from Blaine, Washington to Portland, Oregon. The system transports gasoline, diesel, and jet fuel. This fuel originates at four Puget Sound refineries, two in Whatcom County and two in Skagit County, and is delivered to Seattle's Harbor Island, Seattle-Tacoma International Airport, Renton, Tacoma, Vancouver, Washington, and Portland, Oregon.

Motor gasoline supply/demand

In 2013, PNW refineries produced an average of 253,000 b/d of motor gasoline, including motor gasoline blending components and finished motor gasoline, about 91% of 2013 demand (102% when blended with ethanol). The PNW region also imports and exports gasoline to balance gasoline quality imbalances and is supplied with gasoline from PADD 4 because it is more efficient to supply the eastern part of the region east of the Cascade Range mountains with product from refineries in Salt Lake City, Utah and Billings, Montana. In 2013, the region imported 8,200 b/d of transportation fuels, mostly from Canada, and was supplied with an additional 15,200 b/d from PADD 4 (Rocky Mountains). The PNW typically does not receive product from other regions within PADD 5. In 2013, the region exported 26,000 b/d of motor gasoline, principally to Mexico and Canada.

Figure 22. Pacific Northwest motor gasoline supply/demand balance



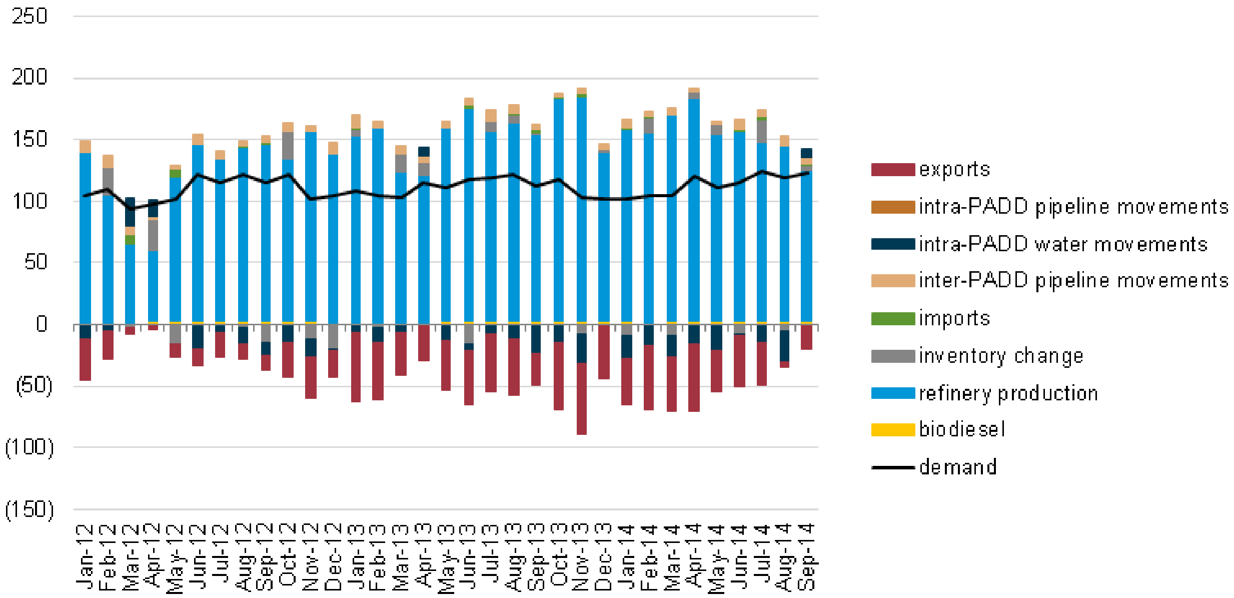
Note: All movements are on a net basis.
Source: Stillwater Associates analysis of EIA data

Distillate fuel supply/demand

The Pacific Northwest produces considerably more distillate fuel than is needed to meet in-region demand. In 2013, the region produced 154,000 b/d of distillate fuel, 138% of demand. The region exports significant volumes of distillate fuel into the Pacific Basin market, 43,200 b/d on average in 2013, to Central and South America, western Canada (which lacks sufficient refining capacity), and Mexico. The Pacific Northwest region also supplies distillate, 10,100 b/d on average in 2013, to the rest of PADD 5 via marine vessel. PADD 4 supplied 5,800 b/d of distillate fuel to the eastern part of the Pacific Northwest region.

Figure 23. Pacific Northwest distillate supply/demand balance

thousand barrels per day



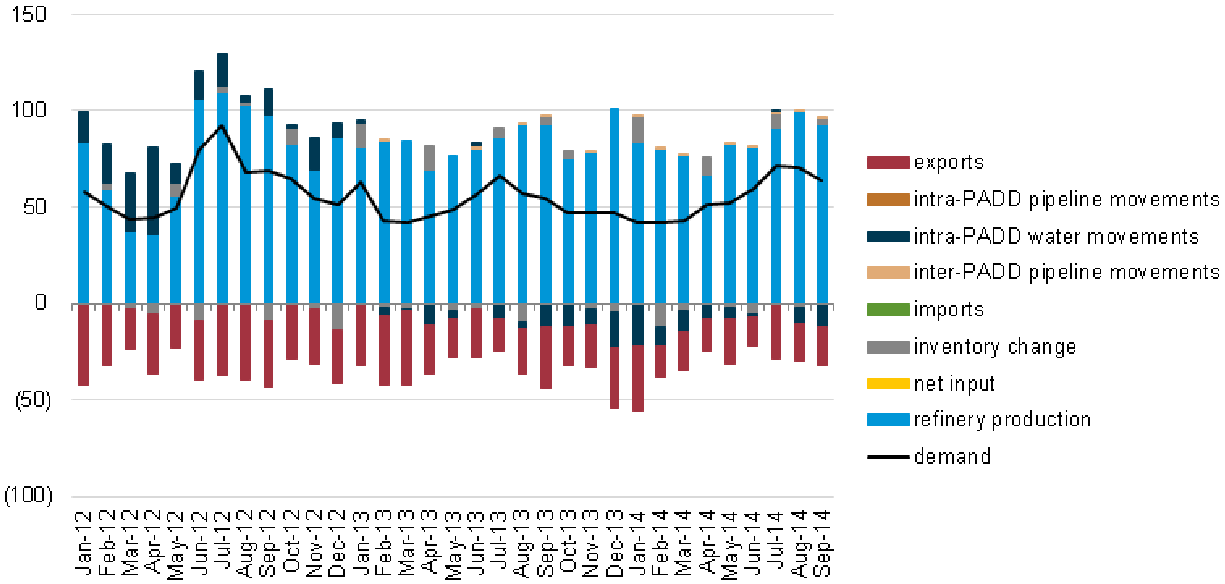
Note: All movements are on a net basis.
Source: Stillwater Associates analysis of EIA data

Jet fuel supply/demand

Refineries in the PNW region produced approximately 163% of in-region jet fuel demand, or 84,000 b/d on average in 2013, making the region significantly net long jet fuel. The oversupply allowed the region to export 27,000 b/d of jet fuel and to send 7,000 b/d of supplies via marine vessel to other regions of PADD 5 on average in 2013. The region's jet fuel exports were mainly destined for Canada, with smaller amounts bound for Central America, South America, and Asia.

Figure 24. Pacific Northwest jet fuel supply/demand balance

thousand barrels per day



Note: All movements are on a net basis.
Source: Stillwater Associates analysis of EIA data

Renewable fuels and biofuels supply/demand

Almost all of the gasoline in the Pacific Northwest is blended with ethanol to a level of 10%, driven by the federal Renewable Fuel Standard program and the state's requirement that diesel fuel sold in Oregon must be blended with a minimum of 5% biodiesel. The Oregon Renewable Fuel Standard, which was adopted in 2005, set the requirement for biodiesel blending in the state. Oregon also has a low-carbon fuels law that was passed in 2009 but for which regulations have not been promulgated. The low-carbon fuel law was scheduled to sunset in 2015, however, in February, the Oregon state senate introduced a bill to make the law permanent. In January, the Oregon Environmental Quality Commission proposed regulations to require fuel importers and producers to reduce the carbon content of transportation fuels by 10% over the next decade, starting in January 2016.

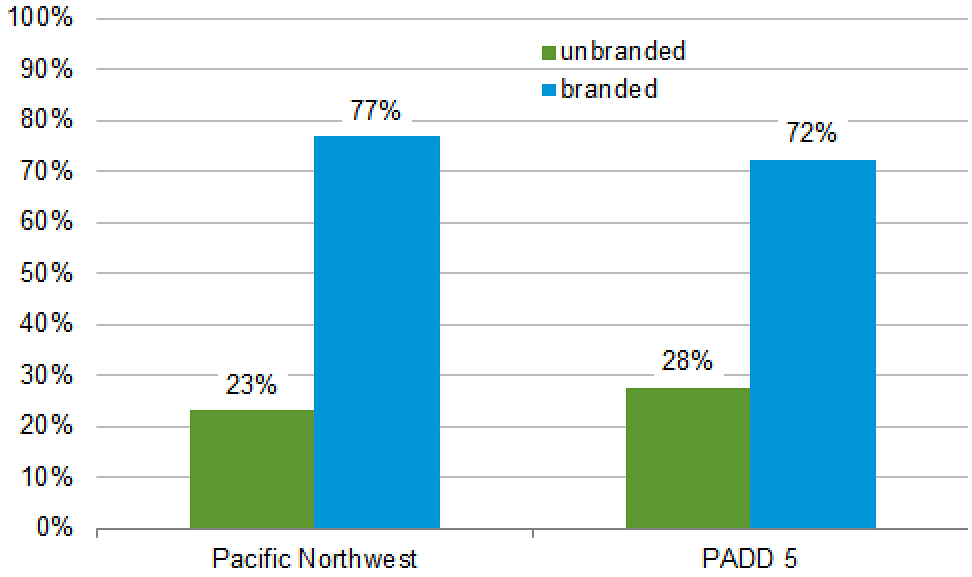
Ethanol supply to the PNW is from a combination of receipts from other PADDs, delivered by rail and truck to blending terminals, and in-region production. Biodiesel, which supplied a small percentage of the region's diesel demand in 2013 (about 2,200 b/d, or about 2% of in-region demand) is supplied primarily from in-region production.

Retail markets

Oregon is one of two states in the country that does not permit customer self-service dispensing of transportation fuels at retail outlets. The mandate has its origins in efforts to support independent gasoline wholesalers, which helped minimize the number of retail outlets owned and operated by major oil companies. The Pacific Northwest actually has a slightly higher percentage of branded outlets compared with PADD 5 overall. The region has about 25 branded and unbranded retailers, with 77% of retail stations selling branded fuels compared with the PADD 5 average of 72%. Brands in the Pacific Northwest include Chevron, Shell, 76, Conoco, ARCO, Pilot, Costco, and Sam's Club.

Figure 25. Pacific Northwest retail market structure

percent of retail outlets



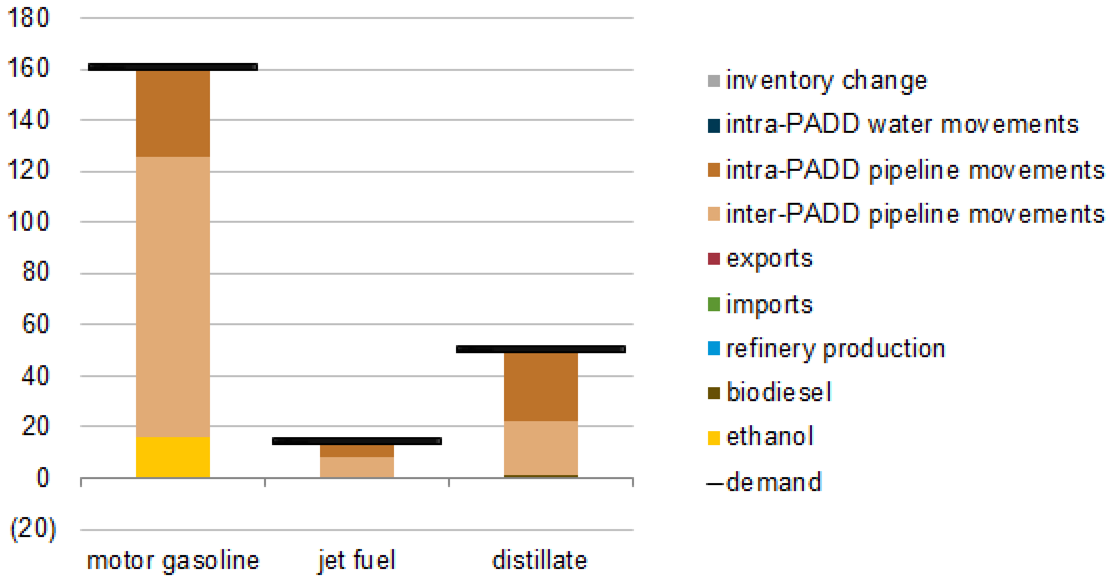
Source: Stillwater Associates analysis of Oil Price Information Service (OPIS) data for the week of December 31, 2014
Note: OPIS data are survey rather than census data, and survey data include transactions from large commercial trucking fleet customers using company credit cards and not from cash or credit card sales to the general public.

Arizona

Arizona accounts for 11% of demand for motor gasoline in PADD 5, 3% of demand for jet fuel, and 10% of distillate fuel demand. There are no petroleum refineries in Arizona, and the region is supplied with product by pipelines that originate in Southern California and West Texas. In 2013 the region consumed 161,500 b/d of motor gasoline, 14,600 b/d of jet fuel, and 50,600 b/d of distillate fuel.

Figure 26. Arizona 2013 supply/demand balance

thousand barrels per day



Note: All movements are on a net basis.
Source: Stillwater Associates analysis of EIA data

Supply and logistics

Arizona is supplied with all transportation fuels via pipeline from Southern California, New Mexico, and Texas. The 400-mile long Kinder Morgan East Line originates in El Paso, Texas and consists of two parallel pipelines that end in Phoenix, Arizona. Refineries in Texas and New Mexico can supply product into the East Line for delivery to five storage and distribution terminals in Phoenix and two in Tucson, Arizona. A disruption to fuel supply from refineries in New Mexico and West Texas into the East Line reduce East Line supply into Arizona as there may not be sufficient fuels supply or pipeline capacity from other sources to replace the lost fuels supply.

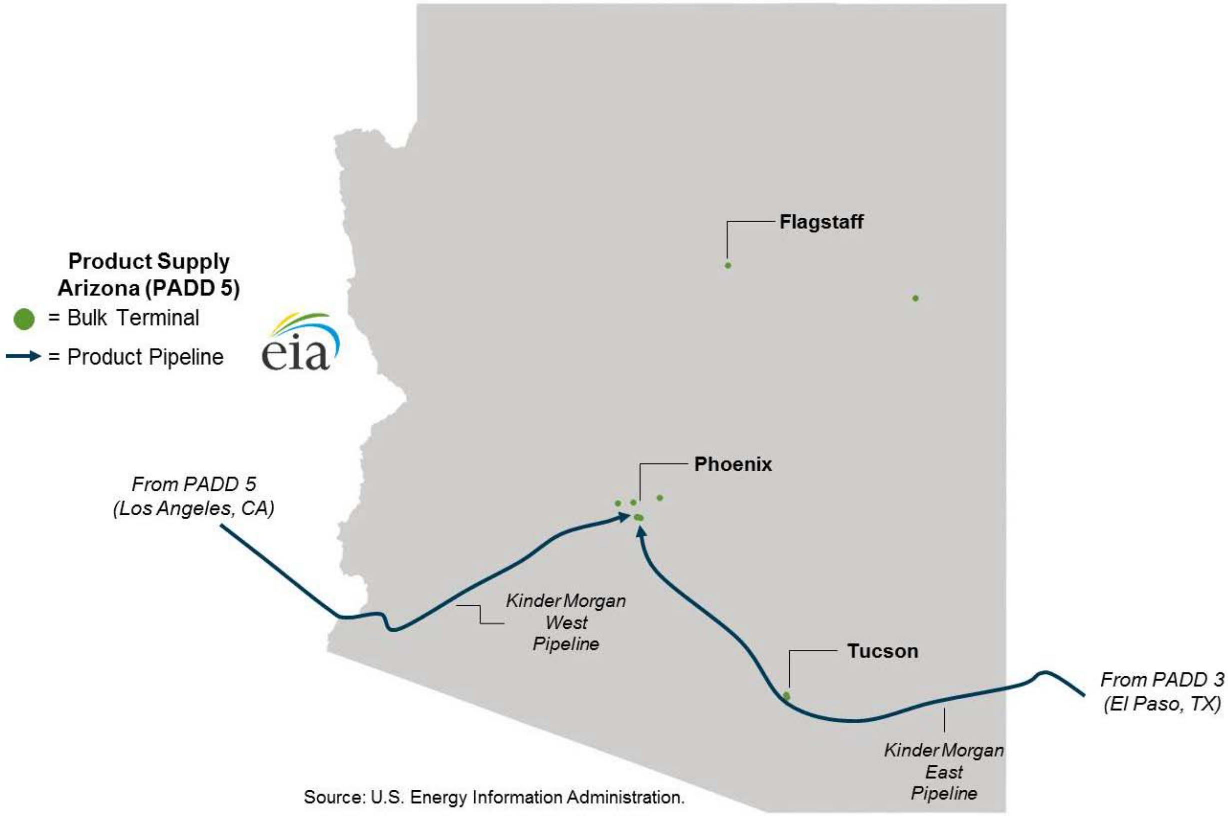
The Kinder Morgan West Line is part of the Kinder Morgan SFPP system. The West Line runs 515 miles from the Watson Station in the Los Angeles Basin to Phoenix, Arizona and delivers product into storage and distribution terminals in Phoenix.

The two pipelines of the East Line operate at close to full capacity, while the West Line operates at well below capacity. As a result, the West Line is a source of incremental supply for Phoenix should supply from the East Line be reduced. However, because the transportation time for fuels delivered into

Phoenix from Los Angeles, California, is about a week to 10 days, incremental supply to Phoenix would not be immediately available. There is no backup pipeline capacity for fuels supply from Phoenix into Tucson. Incremental supply to Tucson is via long-haul trucking.

The Kinder Morgan East and West Lines are critical to fuels supply to Arizona. Train derailments, as well as washouts and pipeline ruptures, have affected the pipelines, sections of which lie in the Union Pacific Railroad right of way. Most disruptions have been of short duration.

Figure 27. Arizona petroleum product flows



Source: U.S. Energy Information Administration.

Motor gasoline supply/demand

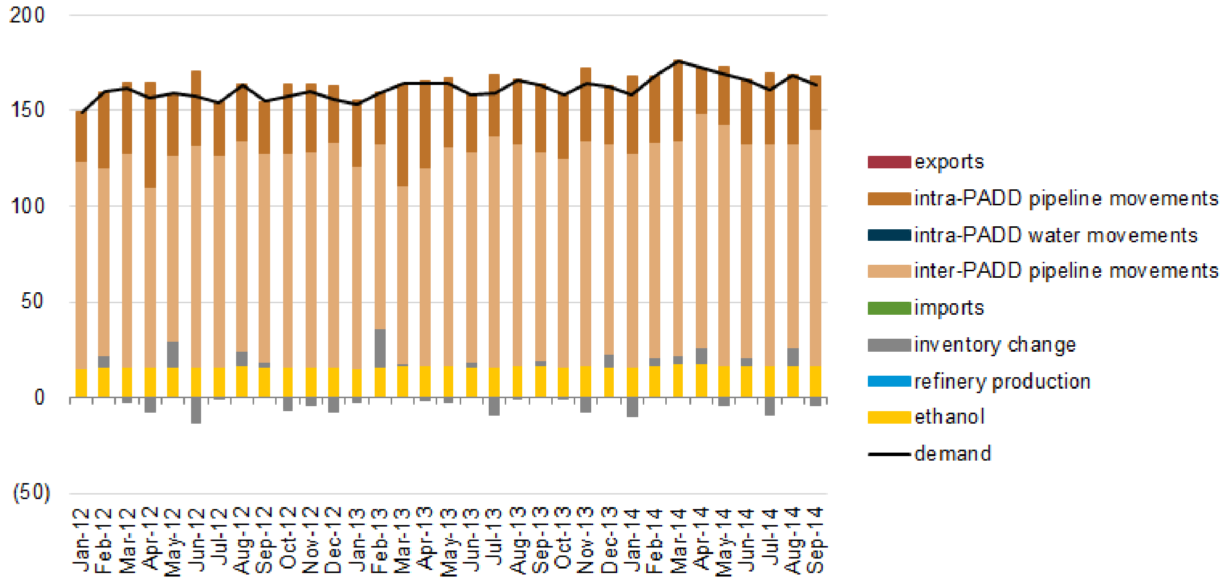
In 2013, Arizona consumed 161,500 b/d of motor gasoline. The Kinder Morgan East pipeline supplied 109,000 b/d, or 67%, of total gasoline from refineries in New Mexico and Texas. An additional 35,000 b/d of gasoline was sourced from Southern California. Arizona's Cleaner Burning Gasoline (CBG) Program calls for a number of different specifications of cleaner burning gasoline in different areas of the state, including the greater Maricopa County area (Phoenix metropolitan area); part of Pinal County, which is between Phoenix and Tucson, and a small portion of Yavapai County; and part of Pima County, which includes the Tucson metropolitan area.

The CBG program has two key elements: a summer cleaner-burning fuel blend with a low Reid Vapor Pressure (RVP) to reduce ozone levels and a winter clean-burning fuel blend with a minimum oxygenate content to reduce carbon monoxide levels. Winter CBG must also meet the specifications for CARB Phase 2 reformulated gasoline. Summer CBG must either meet the winter CARB Phase 2 specifications or meet specifications patterned after the federal Phase 2 reformulated gasoline (RFG) program. As a result, much of the gasoline required in Arizona is similar to CARB or federal RFG, which provides supply advantages. The petroleum component of gasoline blended specifically to meet Arizona gasoline specifications is Arizona Blendstock for Oxygenate Blending (AZBOB).

Arizona's gasoline demand is primarily supplied by shipments from refineries in El Paso, Texas and other refineries on the Gulf Coast, with additional volumes sourced from refineries in Southern California. The same supply pattern exists for jet fuel, with most of the region's jet fuel supplies sourced from the Gulf Coast. However, Arizona's distillate demand is supplied mostly from Southern California refineries, representing that region's relative net length in distillate supplies.

Figure 28. Arizona motor gasoline supply/demand balance

thousand barrels per day



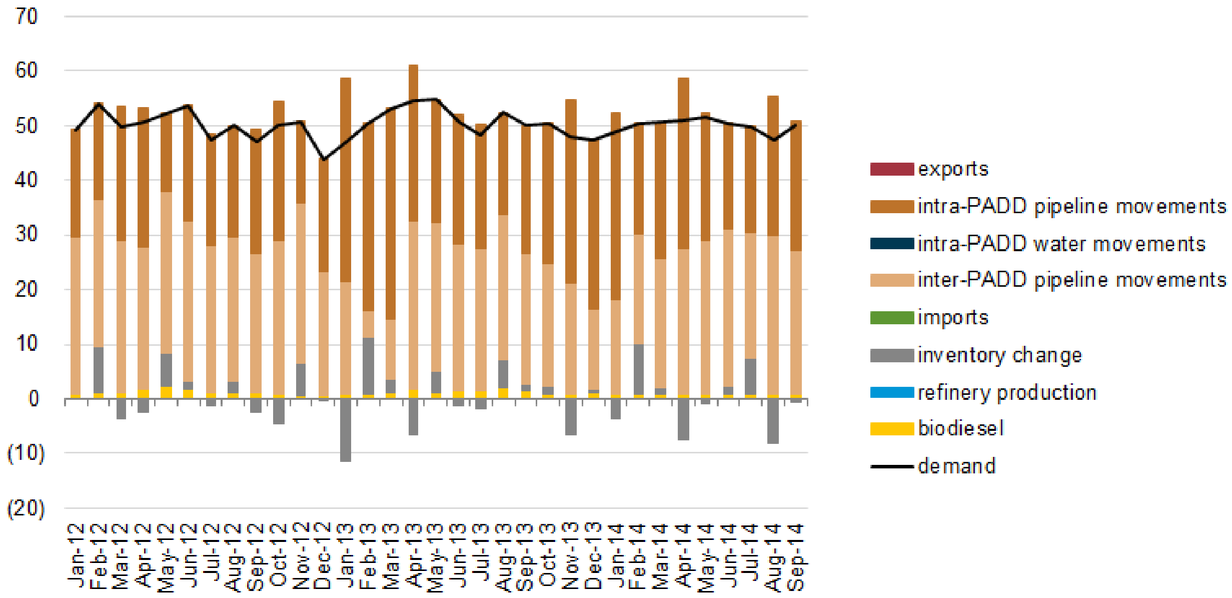
Note: All movements are on a net basis.
Source: Stillwater Associates analysis of EIA data

Distillate fuel supply/demand

In 2013, Arizona region consumed 50,600 b/d of distillate fuel. Supply from Southern California averaged 28,200 b/d (56% of demand), and supply from Texas and New Mexico averaged 21,300 b/d (42% of demand). Biodiesel supplied about 3% of Arizona diesel fuel demand in 2013. Arizona requires ultra-low sulfur diesel, the specifications for which are less restrictive than CARB diesel.

Figure 29. Arizona distillate supply/demand balance

thousand barrels per day



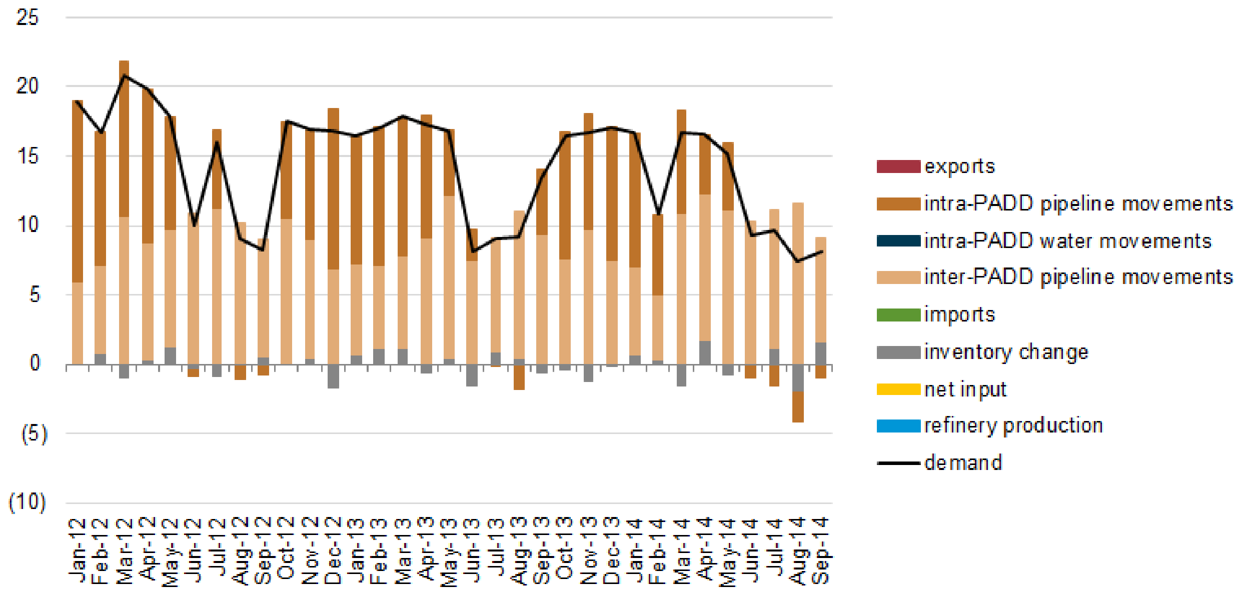
Note: All movements are on a net basis.
Source: Stillwater Associates analysis of EIA data

Jet fuel supply/demand

In 2013, Arizona consumed 14,600 b/d[16] of jet fuel, most of which was supplied from Texas and New Mexico. Jet fuel demand is principally at the Phoenix Sky Harbor International Airport and the Tucson International Airport, both of which are supplied from the Kinder Morgan pipeline systems.

Figure 30. Arizona jet fuel supply/demand balance

thousand barrels per day



Note: All movements are on a net basis.
Source: Stillwater Associates analysis of EIA data

Renewable fuels and biofuels supply/demand

Motor gasoline sold in Arizona is blended with ethanol to an average level of 10%, driven by the federal RFS program and also by the EPA's State Winter Oxygenated Fuel program that requires minimum oxygenate levels to reduce carbon monoxide emissions. The winter oxygenated fuel season is generally October through February or March. Arizona has one ethanol production facility, Pinal Energy, which restarted in March 2014 after having been idle for 18 months. Arizona also has biodiesel production capacity.

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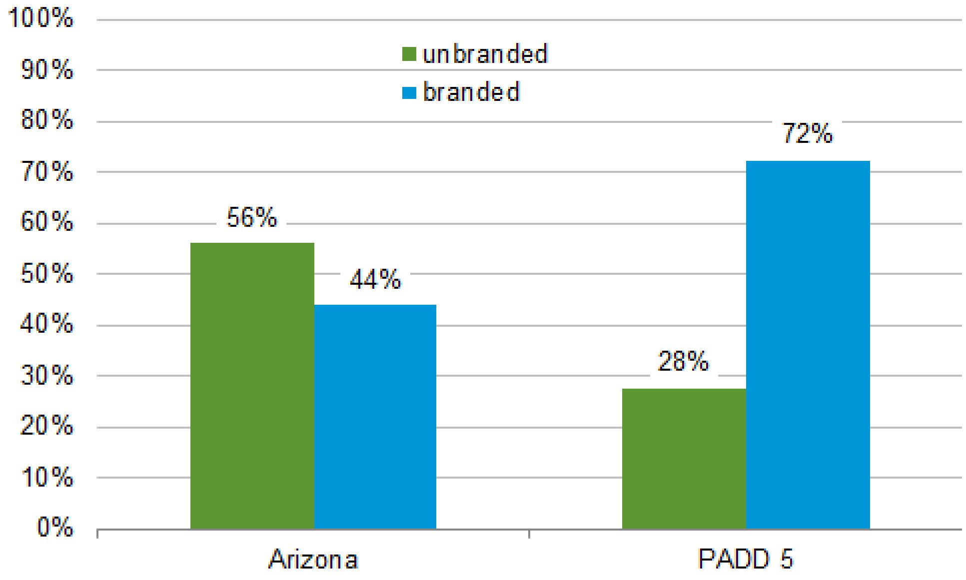
[16] Non-EIA sources of data estimate Arizona jet fuel consumption at higher levels.

Retail market

There are about 23 branded and unbranded fuels retailers operating in Arizona and most, 56%, of the retail outlets are unbranded meaning they are unaffiliated with a major oil company brand, although they may purchase product from a major oil company and market that product under a different brand. Major retail brands in Arizona include Chevron, Circle K, Fry's, Quik Trip, Shell, and Valero.

Figure 31. Arizona retail market structure

percent of retail outlets



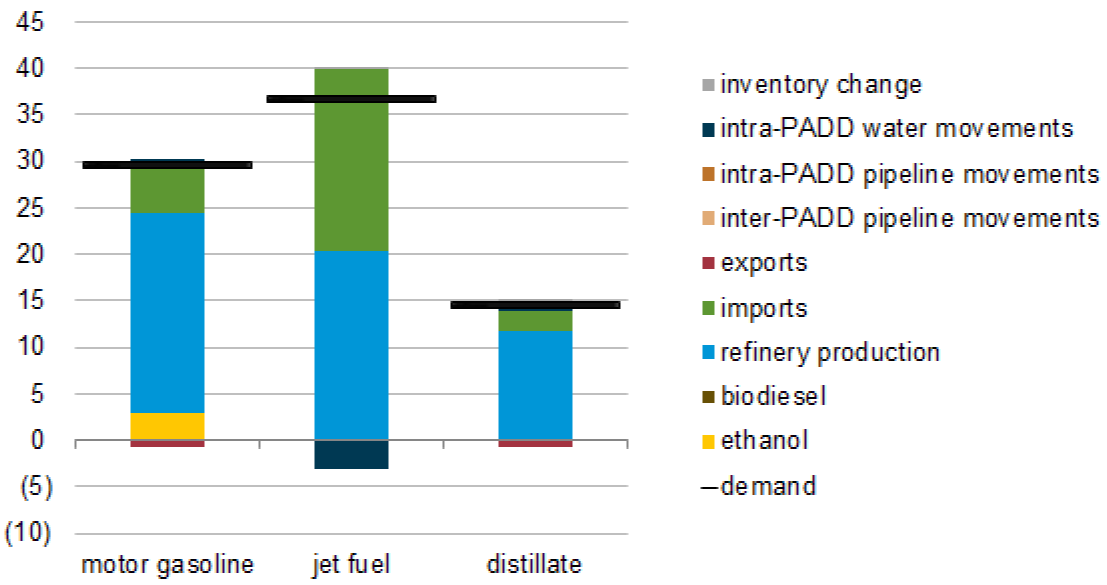
Source: Stillwater Associates analysis of Oil Price Information Service (OPIS) data for the week of December 31, 2014
Note: OPIS data are survey rather than census data, and survey data include transactions from large commercial trucking fleet customers using company credit cards and not from cash or credit card sales to the general public.

Hawaii

Hawaii is remote and isolated from other PADD 5 regional markets and other PADDs. Hawaii relies primarily on in-region refinery production and imports. In 2013, refineries in Hawaii produced 21,500 b/d of motor gasoline, 20,300 b/d of jet fuel, and 11,800 b/d of diesel fuel sufficient to meet 72% of motor gasoline demand, 55% of jet fuel demand, and 81% of distillate fuel demand. Refinery production was supplemented with motor gasoline imports of 5,400 b/d, jet fuel imports of 19,700 b/d, and distillate imports of 2,200 b/d. Hawaii was also supplied with small volumes of motor gasoline and diesel fuel from other PADDs and a small volume of diesel fuel from other PADD 5 regional markets.

The state's island geography supports air travel, and as a result, Hawaii's jet fuel demand, which averaged 36,700 b/d in 2013, is higher than demand for both motor gasoline and diesel fuel. Hawaii's jet fuel demand accounted for 8% of PADD 5 demand in 2013, compared with 2% of motor gasoline and 3% of diesel fuel demand. The state's diesel demand is boosted by demand from the electric power sector and U.S. Navy demand for marine fuels.

Figure 32. Hawaii 2013 supply/demand balance



Note: All movements are on a net basis.
Source: Stillwater Associates analysis of EIA data

Supply and logistics

There are two operating refineries in Hawaii with a combined atmospheric crude distillation unit capacity of 147,500 barrels per calendar day (b/cd). The Chevron Barbers Point refinery with capacity of 54,000 b/cd refines light and very low-sulfur-content crude oil into motor gasoline, distillate fuel, and jet fuel. The Par Petroleum Ewa Beach refinery, doing business as Hawaii Independent Energy, has atmospheric crude distillation capacity of 93,500 b/cd, and produces mostly jet and diesel fuels. The Ewa Beach refinery processes a mix of sweet and moderately heavy crude oils, including imports and oil from the Alaska North Slope. In addition to transportation fuels, Hawaiian refineries produce significant quantities of heavy fuels used in electric power generation.

Table 7. Hawaii refineries

Company	Location	Atmospheric Crude Distillation Unit (ACDU) capacity b/cd	Markets served
Chevron USA	Honolulu (Barbers Point)	54,000	Hawaii
Par Petroleum dba Hawaii Independent Energy	Ewa Beach (Kapolei)	93,500	Hawaii

Source: Stillwater Associates analysis of EIA data

In the first quarter of 2013, the refinery at Ewa Beach (then owned and operated by Tesoro Corporation) was idled and did not operate for several months. As a result, 2013 data on refinery transportation fuels supply are atypical for Hawaiian petroleum product markets. Par Petroleum purchased the Tesoro refinery and restarted it in the second quarter of 2013. The refinery is now doing business as Hawaii Independent Energy. With the restart, supply is now more consistent with historical patterns.

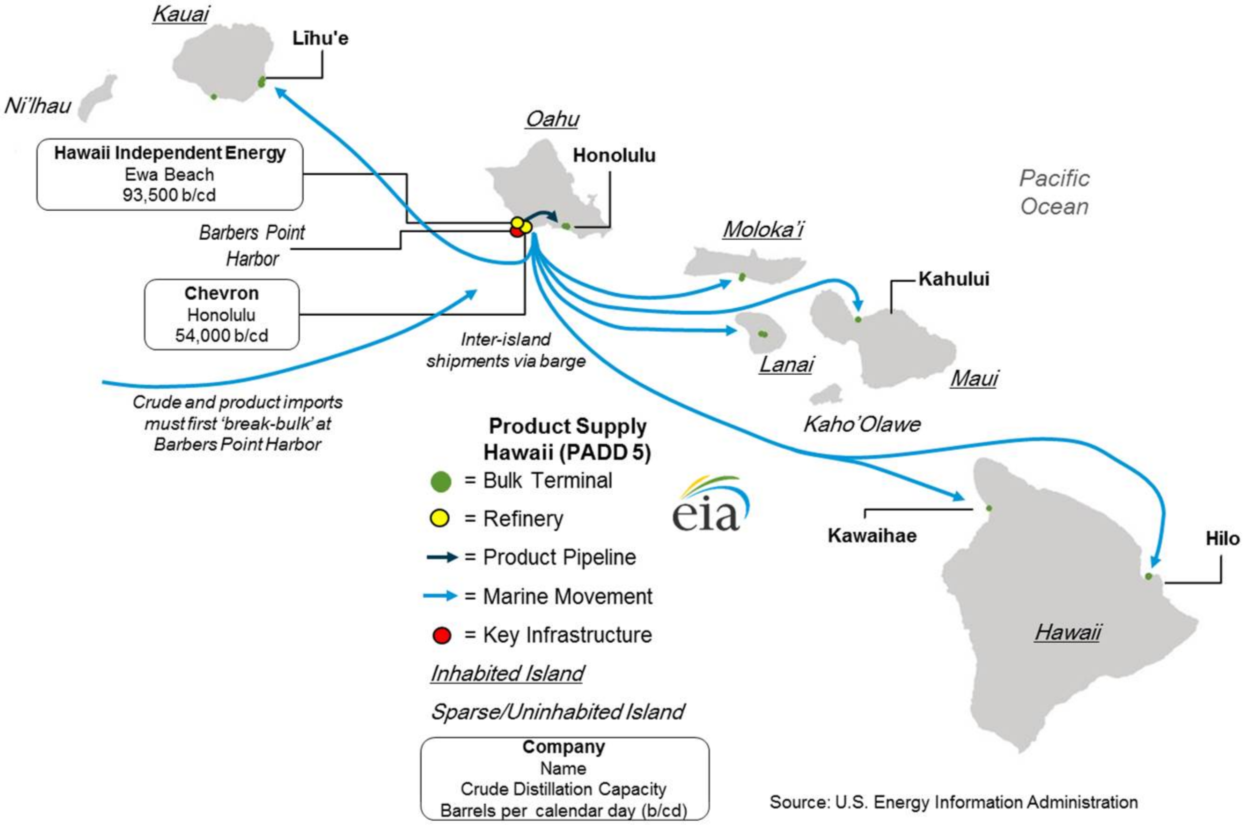
In 2013, refineries in Hawaii produced 21,500 b/d of motor gasoline, 20,300 b/d of jet fuel, and 11,800 b/d of diesel fuel sufficient to meet 72% of motor gasoline demand (81% when blended with ethanol), 55% of jet fuel demand, and 75% of diesel fuel demand. Refinery production was supplemented with motor gasoline imports of 5,400 b/d, jet fuel imports of 19,700 b/d, and diesel imports of 2,200 b/d. Hawaii was also supplied with small volumes of motor gasoline and diesel fuel from other PADDs and supplied a small volume of diesel fuel from other PADD 5 regional markets.

Product from the refineries on Oahu moves by pipeline to supply storage and distribution terminals on Oahu and by marine vessel from the Barbers Point Harbor to terminals on the islands of Maui, Kauai, and Hawaii. Product that arrives in Hawaii by marine vessel from other U.S. regions is also processed through the Barbers Point Harbor where large seagoing marine vessels can be accommodated. Large cargoes are offloaded, and then smaller volumes are shipped by barge to the storage and distribution terminals on the other islands. There are 14 storage and distribution terminals outside the Honolulu area, many of which are small.

Product is also shipped to Honolulu International Airport by pipeline across Pearl Harbor and by truck from Honolulu area terminals.

The two refineries on Oahu and the Barbers Point port facilities and associated barge fleet are critical to Hawaii transportation fuels supply.

Figure 33. Hawaii refineries and petroleum product flows

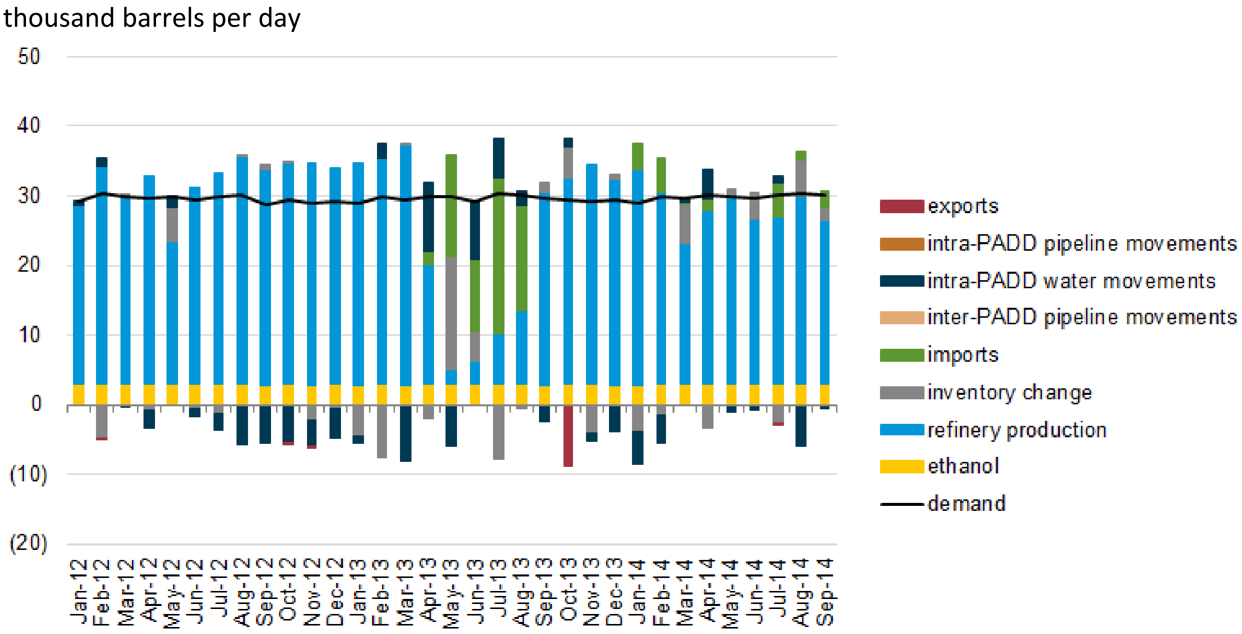


Source: U.S. Energy Information Administration

Motor gasoline supply/demand

Hawaii is typically a tightly balanced market for motor gasoline. In 2012, in-region refinery production when blended with ethanol was sufficient to supply 99% of motor gasoline demand. On average in 2013, in-region refinery production in Hawaii was sufficient to supply only 72% of demand (81% when blended with ethanol). Imports and receipts from other PADDs supplied the balance. After the restart of the closed refinery, EIA data indicate that balances are more consistent with historical levels.

Figure 34. Hawaii gasoline supply/demand balance

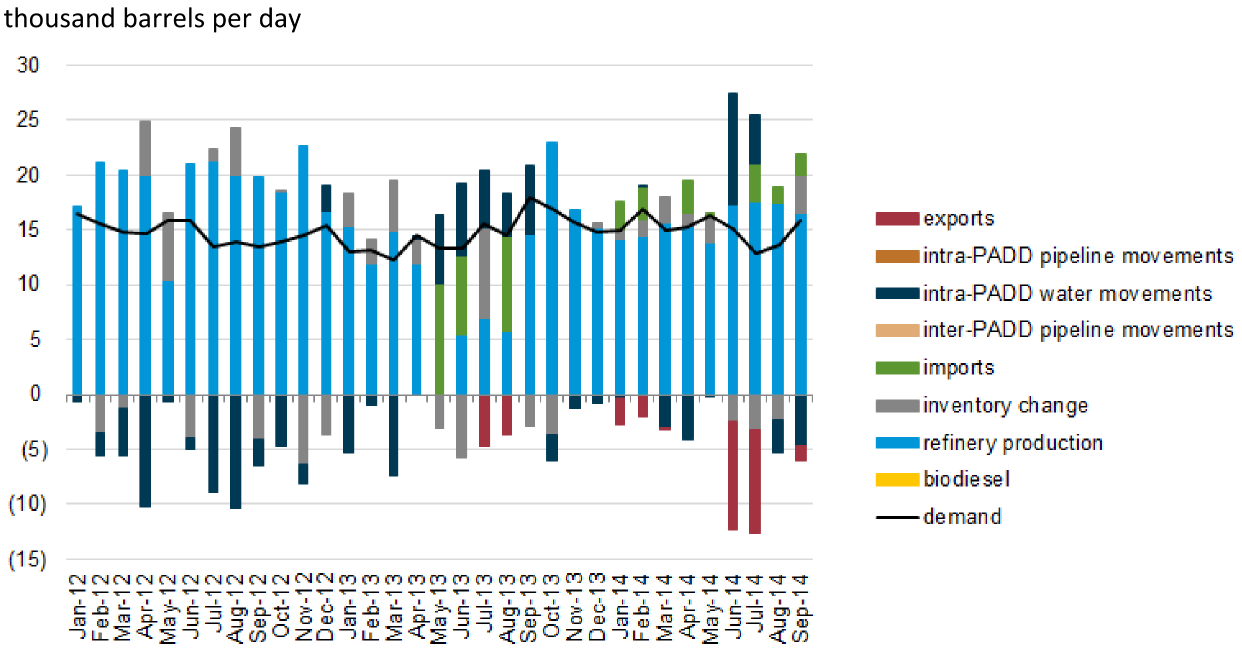


Note: All movements are on a net basis.
Source: Stillwater Associates analysis of EIA data

Distillate fuel supply/demand

Refineries in Hawaii typically produce more distillate fuel than is consumed locally. In 2012, in-region refineries produced 129% of average distillate demand and in the first nine months of 2014 produced 104% of average demand. However, refineries in Hawaii are configured to produce some diesel fuel to meet power generation demand. The refineries also lack de-sulfurization capacity. This creates an imbalance between the distillate fuels produced in Hawaii, with excess supplies of heavy higher-sulfur diesel fuel and a shortage of lower-sulfur distillate fuels like ULSD. As a result, Hawaii exports or ships to other parts of PADD 5 heavier distillate fuels, and either imports ULSD or receives it from other PADD 5 regional markets. The lack of desulfurization capacity at Hawaiian refineries limits crude slate flexibility and favors crude oil with very low sulfur content.

Figure 35. Hawaii distillate fuel supply/demand balance

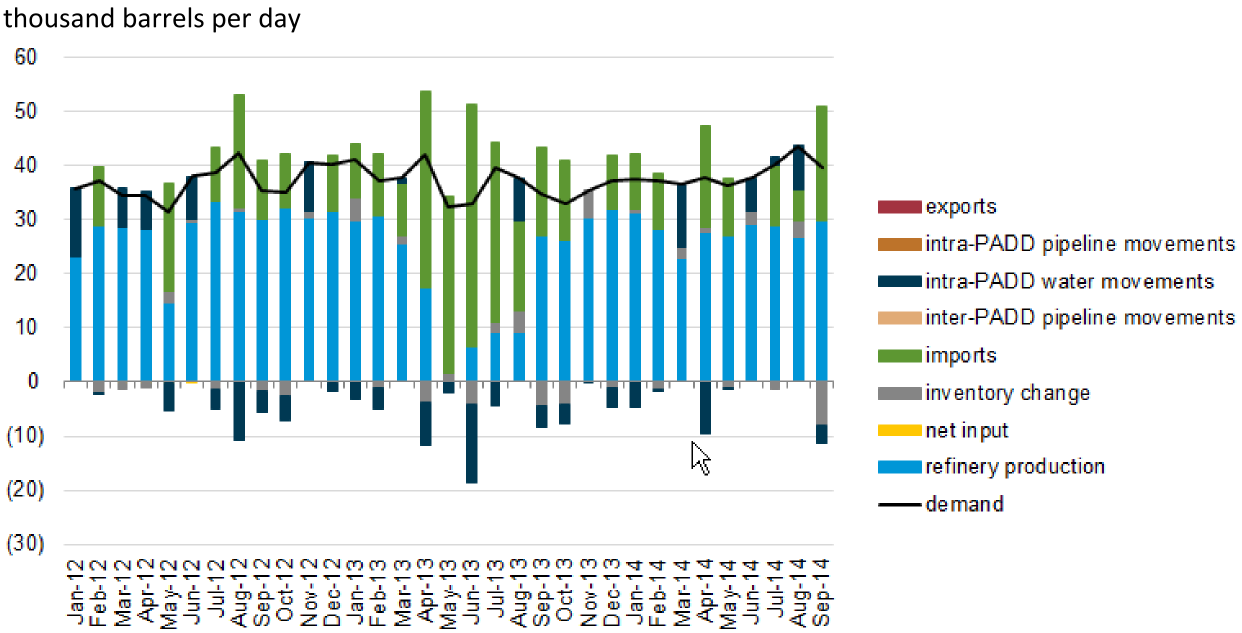


Note: All movements are on a net basis.
Source: Stillwater Associates analysis of EIA data

Jet fuel supply/demand

Hawaii consumes more jet fuel than motor gasoline or diesel fuel. As in-region refineries cannot produce sufficient quantities of jet fuel to meet demand, Hawaii imports substantial volumes of jet fuel. In 2013, Hawaii imported 19,700 b/d of jet fuel (54% of demand) and in 2012 the state imported jet fuel to meet 21% of demand. Jet fuel is occasionally transferred to Hawaii from other regions of PADD 5.

Figure 36. Hawaii jet fuel supply/demand balance



Note: All movements are on a net basis.
Source: Stillwater Associates analysis of EIA data

Renewable fuels and biofuels supply/demand

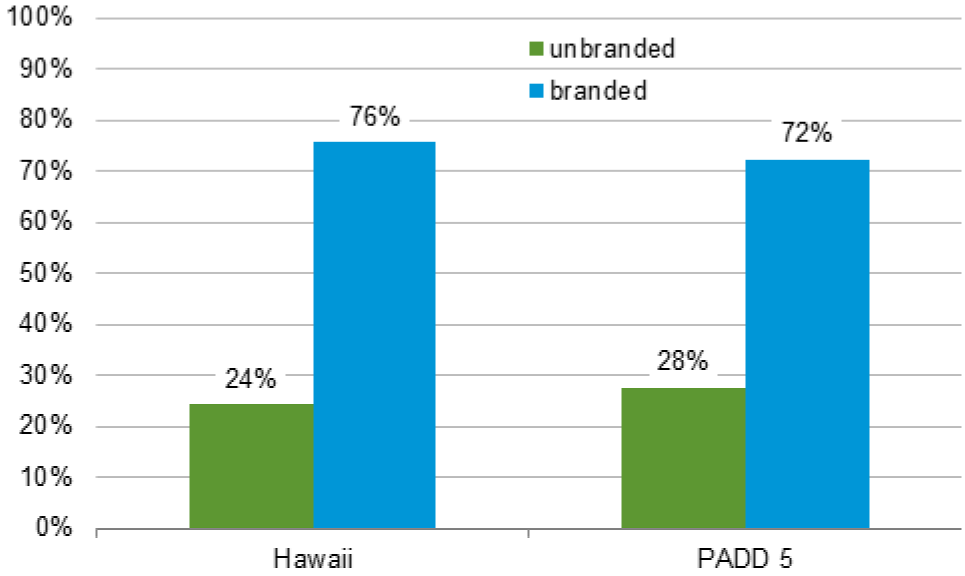
Transportation fuels sold in Hawaii must comply with the federal Renewable Fuels Standard (RFS) that mandates transportation fuels sold in the United States contain a minimum volume of renewable fuels. However, Hawaii recently passed legislation to eliminate the mandate to blend ethanol into gasoline. It is unclear what practical impact the legislation will have because producers will still be required to blend renewable fuel into gasoline and diesel under the federal Renewable Fuel Standard program. Ethanol is currently shipped to Hawaii from the other regional markets in PADD 5 or from Brazil. Ethanol shipped from the West Coast typically originates in the Midwest and moves to the West Coast by rail. Plans to produce ethanol in Hawaii using locally grown feedstocks have been slow to materialize despite state incentives.

Retail market

There are about nine branded and unbranded retailers of transportation fuels in Hawaii, and 76% of retail outlets sell branded fuels. Chevron, 76, Aloha, Tesoro, and Shell are among the major retail brands in Hawaii.

Figure 37. Hawaii retail market structure

percent of retail outlets



Source: Stillwater Associates analysis of Oil Price Information Service (OPIS) data for the week of December 31, 2014
Note: OPIS data are survey rather than census data, and survey data include transactions from large commercial trucking fleet customers using company credit cards and not from cash or credit card sales to the general public.

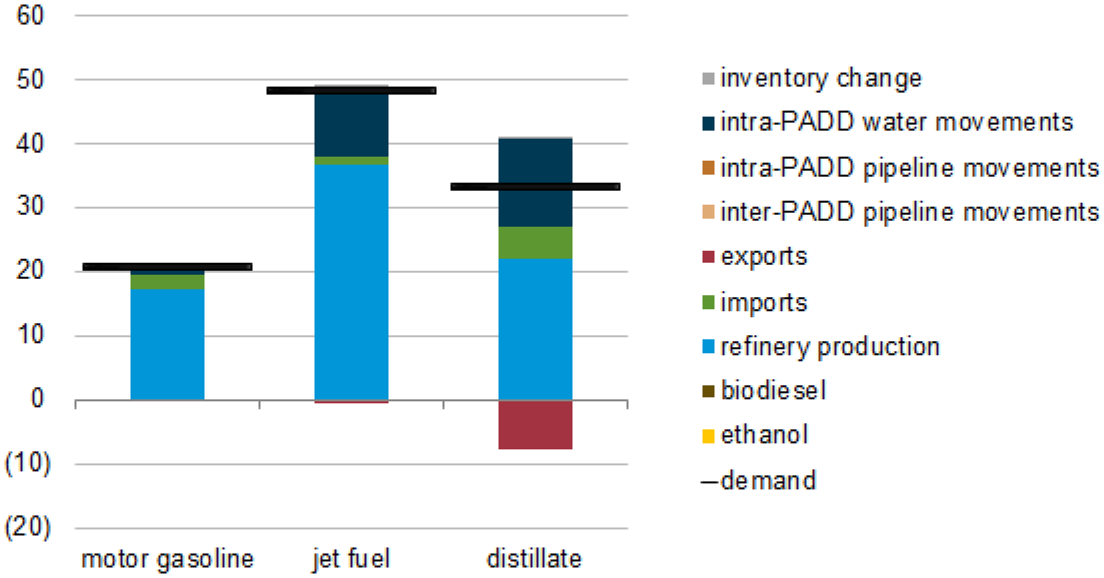
Alaska

Alaska has the lowest population of all PADD 5 regions, and as a result, Alaska's demand for motor gasoline accounts for a small percentage of total PADD demand. However, the region's remoteness and wide geographic expanse make air travel essential, and Alaska's demand for jet fuel is higher than for motor gasoline. The region's distillate fuel demand is supported by resource extraction activities and oil production in the north. In 2013, Alaska's demand for motor gasoline was 20,800 b/d, less than 2% of total PADD 5 demand; jet fuel demand was 48,400 b/d, 11% of PADD 5 demand; and diesel fuel demand was 33,400 b/d, 7% of PADD 5 demand.

The region is supplied primarily by in-region refinery production, by production from refineries in other regions of PADD 5 that is delivered by marine vessel from Washington and California, and by imports.

Figure 38. Alaska 2013 supply/demand balance

thousand barrels per day



Note: All movements are on a net basis.
Source: Stillwater Associates analysis of EIA data

Supply and logistics

There are five operating refineries in Alaska with combined atmospheric crude distillation unit capacity of 165,200 barrels per calendar day (b/cd). A sixth refinery, Flint Hills Resources North Pole refinery, with 126,535 b/cd crude distillation capacity, was closed in 2014 and is being dismantled and converted to a storage and distribution terminal.

The operating refineries are dispersed across the state. On the North Slope, two of the three major crude oil producers, BP and ConocoPhillips, operate small distillation-only refineries that process Alaska North Slope (ANS) crude oil to produce artic diesel fuel for production operations. The refineries inject unsold distillation products back into the Trans-Alaska Pipeline System (TAPS). Petro Star also operates two distillation-only refineries, one in North Pole in central Alaska and the other in Valdez in southern Alaska. Both of these facilities blend unsold distillation products back into TAPS.

Tesoro operates the largest and most complex refinery in Alaska at Kenai. The Tesoro refinery produces a wider range of transportation fuels, including motor gasoline, jet fuel, and diesel fuel. The refinery also produces asphalt.

Table 8. Alaska refineries

Company	Location	Atmospheric Crude Distillation Unit (ACDU) capacity b/cd	Markets served
Tesoro	Kenai	65,000	Anchorage
Petro Star	Valdez	55,000	South Alaska/Islands
Petro Star	North Pole	19,700	Fairbanks/Central Alaska
Conoco Phillips	Prudhoe Bay	15,000	Conoco Phillips Production Operations
BP	Prudhoe Bay	10,500	BP Production Operations

Source: Stillwater Associates analysis of EIA data

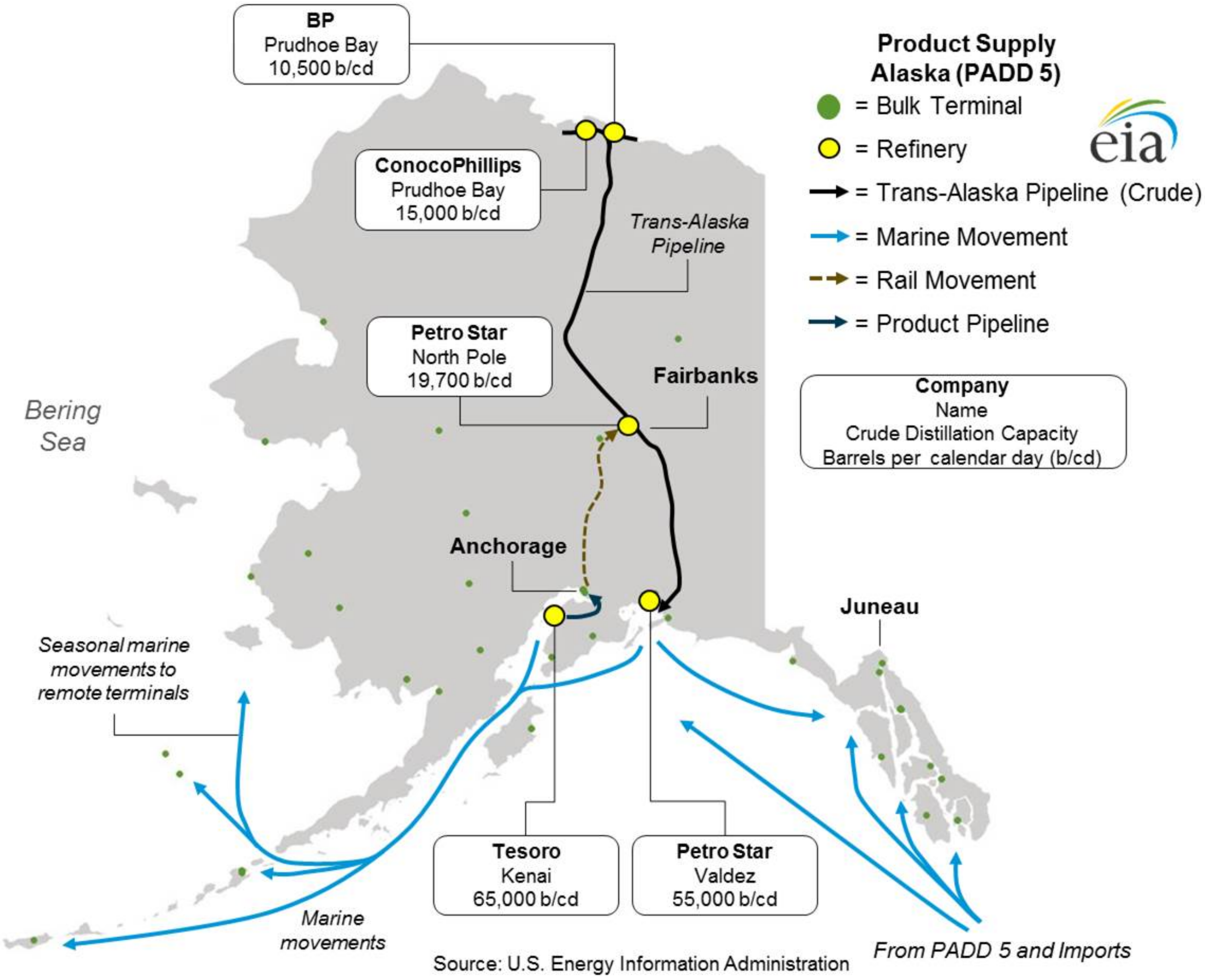
On an annual average basis, the refineries in Alaska supply 83% of motor gasoline demand, 76% of jet fuel demand, and 66% of diesel fuel demand. However, Alaska’s seasonal weather patterns result in seasonal differences in consumption. Supply/demand balances and supply patterns vary across the year. Refinery supply is supplemented with receipts from other PADD 5 regions and imports. Product is regularly supplied to southeastern Alaska by marine vessel from Washington and California. Alaska also exports a small amount of fuel to Canada and Asia.

Shipment of product within Alaska is by pipeline between Kenai and Anchorage, by rail between Anchorage and Fairbanks, and by marine vessel. The Anchorage-to-Fairbanks rail line and the pipeline to Anchorage are critical to the supply chain.

There are 42 small storage/distribution terminals outside the Anchorage area that serve isolated areas. Deliveries to some locations are seasonal, occurring only during the summer and fall when barge movements are possible. In Southeast Alaska, where there are few roads, fuels are supplied by barge from the U.S. West Coast and Canada.

Jet fuel is delivered to the Ted Stevens International Airport via both pipeline and trucks from Anchorage-area terminals.

Figure 39. Alaska refineries and petroleum product flows



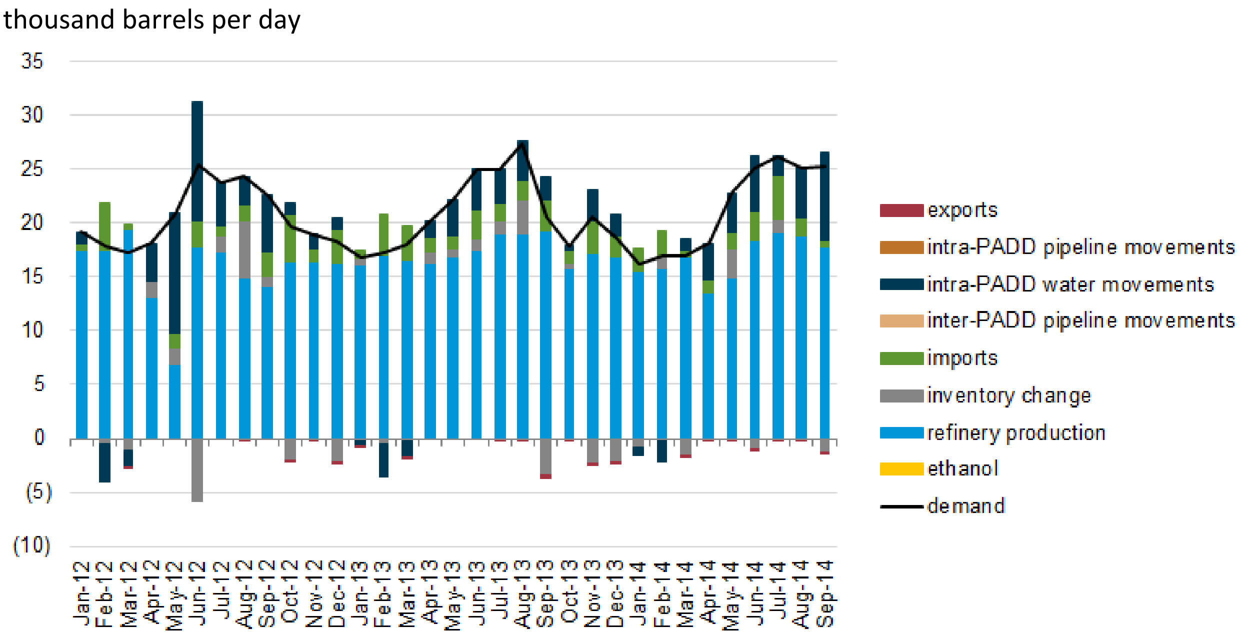
Source: U.S. Energy Information Administration

Motor gasoline supply/demand

Motor gasoline demand in Alaska is highly seasonal. Demand in the peak summer months is significantly higher than in the winter months. In the winter months, in-region refinery production of gasoline is almost sufficient to meet demand; during the summer, a combination of imports and marine deliveries from other PADD 5 regions supplements in-region refinery production. In 2013, Alaska motor gasoline demand averaged 20,800 b/d. In January 2013, demand was about 16,800 b/d and in July demand was 25,000 b/d.

Alaska does not require the blending of ethanol with motor gasoline so ethanol does not represent the typical 9%–10% of motor gasoline as it does in other regions of PADD 5.

Figure 40. Alaska motor gasoline supply/demand balance

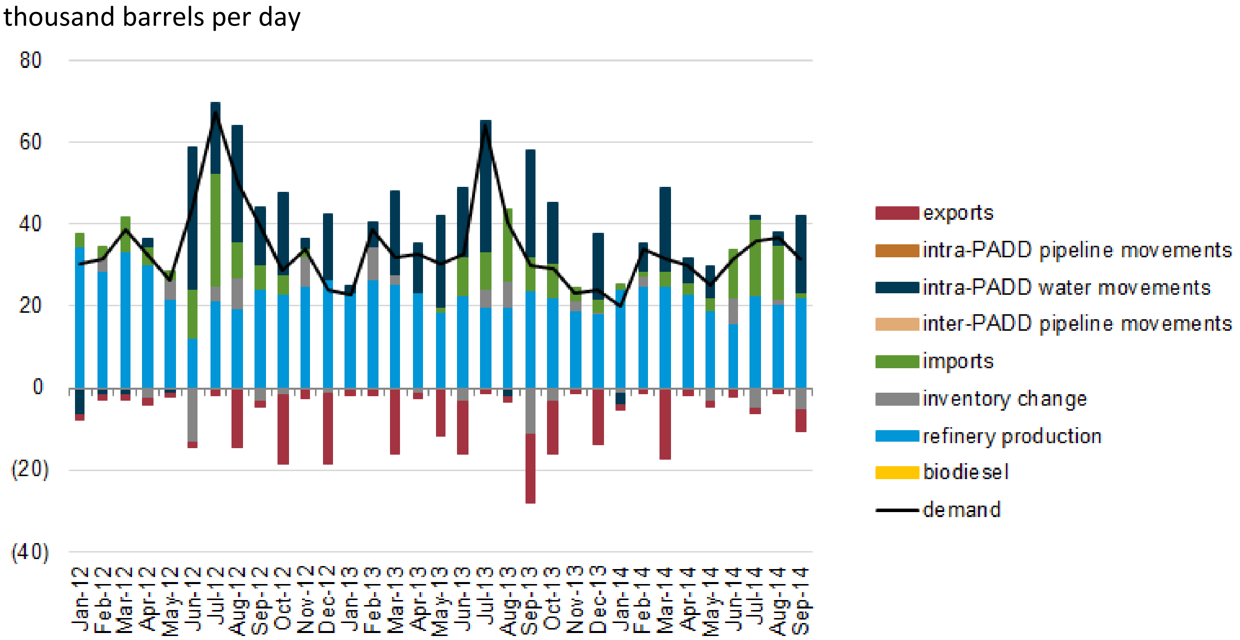


Note: All movements are on a net basis.
Source: Stillwater Associates analysis of EIA data

Distillate fuel supply/demand

Alaskan distillate demand, 33,400 b/d on average in 2013, is supplied mostly by in-region refinery production (66%), imports (15%), and marine movements from other regions (41%). Some of the refineries in Alaska's North Slope produce off-road diesel fuels for use in oil and natural gas exploration and production activities. Diesel is also exported from Alaska to Canada and Asia.

Figure 41. Alaska distillate fuel supply/demand balance

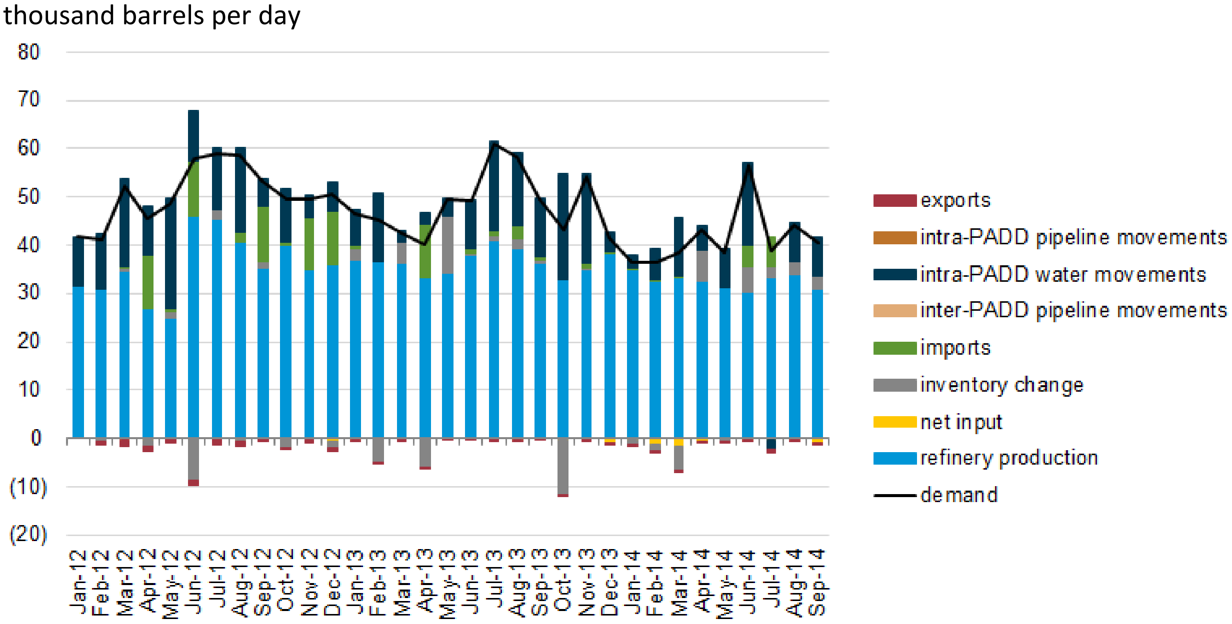


Note: All movements are on a net basis.
Source: Stillwater Associates analysis of EIA data

Jet fuel supply/demand

Jet fuel is a critical transportation fuel in Alaska. With vast distances to cover across rugged terrain, aviation is often the only way to access many parts of the state. Alaska's jet fuel consumption of 48,400 b/d on average in 2013 accounts for 11% of PADD 5 jet fuel demand. Jet fuel demand is typically higher in summer months than in winter. In-region refineries produced jet fuel sufficient to supply 76% of average demand in 2013. Imports of 1,500 b/d and receipts of jet fuel from other PADD 5 regions, Washington and California, supplied the balance.

Figure 42. Alaska jet fuel supply/demand balance



Note: All movements are on a net basis.
Source: Stillwater Associates analysis of EIA data

Renewable fuels and biofuels supply/demand

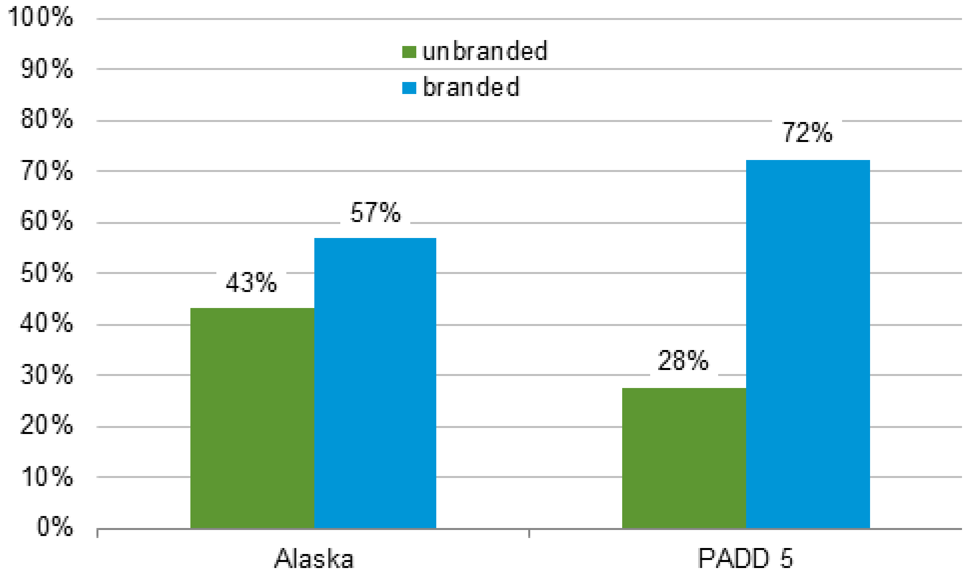
There is minimal biofuels demand in Alaska. There is no requirement to blend ethanol into motor gasoline. EIA data indicate that there is one biodiesel production facility in the state as of April 2015.

Retail market

There are 9 branded and unbranded retailers with approximately 165 retail outlets in Alaska. Most of the retail locations (57%) are branded. Major retail brands include Holiday, Tesoro, Chevron, and Shell.

Figure 43. Alaska retail market structure

percent of retail outlets



Source: Stillwater Associates analysis of Oil Price Information Service (OPIS) data for the week of December 31, 2014
Note: OPIS data are survey rather than census data, and survey data include transactions from large commercial trucking fleet customers using company credit cards and not from cash or credit card sales to the general public.

Tracking and Evaluation of Benefits and Impacts of Greenhouse Gas Limits in Disadvantaged Communities: Initial Report

Office of Environmental Health Hazard Assessment

California Environmental Protection Agency

February 2017

OEHHA

SCIENCE FOR A HEALTHY CALIFORNIA

Preface

This report has been prepared in response to a directive issued by Governor Brown for an analysis of the state’s response to climate change under the Global Warming Solutions Act of 2006 (AB 32). Specifically, the directive calls for the Office of Environmental Health Hazard Assessment (OEHHA) to prepare a report analyzing the benefits and impacts of the greenhouse gas emissions limits adopted by the California Air Resources Board (ARB) within disadvantaged communities. OEHHA is to update the report at least every three years.

The state’s climate policies (e.g., Cap-and-Trade, zero emissions vehicles, renewable energy, low carbon fuel standard) are reducing greenhouse gas emissions statewide as well as contributing to reductions in other pollutants. This report is the first step in an investigation of whether the design and implementation of these climate policies are facilitating decreases or increases in pollutants of concern in disadvantaged communities.

OEHHA's mission is to protect and enhance public health and the environment of California through the evaluation of risks posed by hazardous substances. To carry out that mission, OEHHA provides scientific assistance to the state's other environmental and health agencies on projects involving hazard identification, exposure and toxicity assessment, and health and ecological risk assessment. The mission of ARB is to promote and protect public health, welfare and ecological resources through the effective and efficient reduction of air pollutants while recognizing and considering the effects on the economy of the state.

The focus of this initial report is on large stationary sources in the Cap-and-Trade Program, one of the elements of the state’s climate change programs that is aimed at gradually reducing greenhouse gas emissions from large industrial sources through a market-based mechanism. It is limited in scope, but aims to be a starting point for future analyses. Later reports will also address the benefits and impacts of other AB 32 programs to reduce greenhouse gas emissions. The report does not explore the benefits associated with investments of Cap-and-Trade auction revenue. Subsequent reports will investigate impacts such as changes in toxic air contaminants emitted by mobile sources.

This report is one of several efforts by researchers and government entities to address air-quality impacts on disadvantaged communities. Cushing *et al.* (2016) investigated the locations and pollution from large stationary sources of greenhouse gas emissions in California that are covered under the Cap-and-Trade Program. ARB continues to implement its adaptive management program to identify and track emissions increases, if any, that are attributable to implementing the Cap-and-Trade Program. AB 197 (Garcia, Statutes of 2016) directs ARB to prioritize programs to achieve direct emissions reductions from large stationary sources and mobile sources. AB 197 also requires ARB to graphically display data on the emissions of greenhouse gases, criteria pollutants, and toxic air contaminants on its website. These efforts over time will improve our knowledge of how California's climate change programs and older, more established regulatory programs affect emissions levels of criteria and toxic pollutants, and improve our understanding of emissions changes attributable to actions taken pursuant to AB 32.

In summary, OEHHA's work here complements other efforts underway to understand potential impacts from the state's various programs to reduce greenhouse gas emissions. There are also efforts to increase access to information on stationary-source emissions for a range of pollutants. This information is expected to inform future proposals to require further reductions in emissions of criteria, toxic, and greenhouse gases from industrial sources.

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Executive Summary

In the ten years since the enactment of the California Global Warming Solutions Act of 2006 (also known as AB 32), concerns have been expressed that the state's trailblazing efforts to reduce greenhouse gas (GHG) emissions may unintentionally impact low-income communities that are already burdened by pollution from multiple sources. More specifically, the concerns are that the state's GHG-reduction programs could prompt regulated businesses to make decisions resulting in more air pollution from facilities in those communities than would otherwise be the case even while statewide GHG emissions decrease.

Conversely, California's climate-change programs also offer the potential to benefit these low-income industrial communities, to the extent that the programs prompt investments by regulated businesses that reduce emissions of both GHGs and conventional air pollutants in the communities where they operate.

In December 2015, Governor Brown directed the Office of Environmental Health Hazard Assessment (OEHHA) to analyze possible benefits and impacts to communities identified as disadvantaged under SB 535 (De León, Chapter 830, Statutes of 2012) from the GHG-emissions limit adopted by the California Air Resources Board. These benefits and impacts include changes in emissions of GHGs, toxic air contaminants, and criteria air pollutants.

This is an initial report that provides the starting point for future, more comprehensive analyses of the impacts on disadvantaged communities of GHG-emission limits. As discussed below and in the body of the report, the emissions data available at this time do not allow for a conclusive analysis. This report makes some preliminary findings that OEHHA expects to build upon in future analyses as it acquires and evaluates more data. It does not provide definitive findings regarding the effects of the GHG limit on any individual community, or disadvantaged communities in general.

The focus of this first report is on one specific AB 32 program, the state's Cap-and-Trade Program. This program regulates facilities that produce a significant fraction of the state's GHG emissions, as well as toxic co-pollutants. There are adequate data available from the Cap-and-Trade Program to begin an evaluation of potential benefits and impacts from changes in emissions. Other GHG reduction programs will be covered in later report as more data related to these programs become available.

In time, the analysis of the Cap-and-Trade Program aims to address the following key questions:

- *How do emissions of GHGs relate to emissions of toxic air contaminants and criteria air pollutants from the same facility?*

- *Are emissions disproportionately occurring in SB 535 disadvantaged communities? Do disadvantaged communities benefit from or are they negatively impacted by changes in GHG emissions from facilities subject to Cap-and-Trade?*
- *Are the benefits and impacts due to the design of the Cap-and-Trade Program?*

While challenges described in this report preclude definitive answers to these questions, OEHHA's initial analysis in this report makes the following findings:

1. A disproportionate number of facilities subject to the Cap-and-Trade Program are located in SB 535 disadvantaged communities. The Cap-and-Trade Program covers several hundred facilities from different industrial sectors that are located across the state. Of the 281 facilities with street addresses that could be geocoded, more than half (57 percent) are located in or within one-half mile of an SB 535 disadvantaged community[1]. More specifically, 15 of 20 refineries (75 percent), 5 of 7 hydrogen plants (71 percent) and 72 of the 110 facilities classified by ARB as "other combustion source" facilities (65 percent) are located in or within one-half mile of a disadvantaged community. While people's actual exposures to toxic co-pollutants emitted from these facilities would depend on various factors such as meteorological conditions and smokestack heights, changes in co-pollutant emissions resulting from the Cap-and-Trade Program would nonetheless tend to have disproportionate benefits (if emissions decrease) or adverse impacts (if emissions increase) on disadvantaged communities because of their proximity to these facilities.

2. There were moderate correlations between GHG emissions and the emissions of criteria air pollutants. The strongest correlation was with fine particulate matter emissions (PM2.5). There was also moderate correlation between GHG and toxic chemical emissions across the entire set of Cap-and-Trade facilities with covered emissions. Some individual industrial sectors showed greater correlations between emissions of GHGs and toxic co-pollutants. Refineries overall showed a strong correlation, while cement plants showed a moderate correlation. Oil and gas production facilities also showed a moderate correlation, depending on the statistical measure used. Facilities in certain sectors with broad ranges in emissions levels (e.g. electricity generation facilities) showed increased correlation with a specific statistical analysis (logarithmic transformation). This report only looked at emissions from one recent year (2014), however, because this was the only year for which air toxics data could be obtained in time for this analysis.

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[1] Identified in 2014. More on the identification of these communities can be found on CalEPA's website at the following URL: http://calepa.ca.gov/EnvJustice/GHGInvest/.

3. OEHHA also conducted a more detailed case study of nine cement plants and 19 refineries. These facilities have relatively high toxicity-weighted emissions, and data for the years 2011-2014 were available. The different plants showed varying levels of correlation among GHG, toxicity-weighted emissions, and PM2.5 emissions during the four-year period. Several cement facilities showed modest positive correlations between GHG and toxicity-weighted emissions, while two cement facilities showed poorer correlations. For refineries, there generally was a positive correlation between GHG and toxicity-weighted air emissions. Facilities with high levels of GHG emissions generally had higher PM2.5 and toxicity-weighted emissions. There were some differences among individual refineries in the relationships between GHGs, toxicity-weighted and PM2.5 emissions, perhaps reflecting differences in the kinds of products made at each of the refineries.

4. These results indicate that the relationship between GHGs and other pollutant emissions is complex. GHG facilities that emit higher levels of GHGs tend to have higher emissions of toxic air contaminants and criteria air pollutants. There is a need for additional investigation into the factors that drive emission changes, how GHG emission reductions are likely to be achieved in different industrial sectors, and what that may mean for concomitant changes in emissions of toxic air pollutants. Nonetheless, these analyses suggest that reductions in greenhouse gas emissions are likely to result in lower pollutant exposures in disadvantaged communities, based overall on the positive correlations observed for the 2014 data.

Limited data availability prevented OEHHA from conducting a more comprehensive analysis in time for this report. The Cap-and-Trade Program is a relatively new program, with the first auction of emissions instruments occurring in 2012. In 2013-2014, the program covered large industrial sources and electricity generation. In 2015, the program expanded to cover emissions from combustion of gasoline and diesel, as well as natural gas use in commercial and residential applications. In these early days of the program, it is hard to discern trends and make firm conclusions regarding patterns of changes in GHG emissions resulting from the program.

Further, data are not yet available to broadly cover emissions of toxic air pollutants from all facilities subject to the Cap-and-Trade Program. Data on emissions of GHGs, criteria air pollutants and toxic air pollutants are collected by multiple entities under different programs and statutory mandates. To date, there is no co-reporting of GHG and toxic emissions, and differences in reporting requirements across regulatory programs complicates data analysis. OEHHA will continue to acquire and analyze data for future reports, which will build upon the initial findings presented in this report.

In addition, toxic emissions data for many facilities are only updated every four years, further limiting conclusions that can be reached. OEHHA currently only has a limited set of data to examine changes in emissions that would illuminate statewide patterns, especially with respect to disadvantaged communities. A further complexity for the analysis is that the relationships between GHG and co-pollutant emissions vary across different industrial sectors (and even within facilities within a sector) with the differences in fuel types and sources, industrial processes and chemical feedstocks.

Therefore, at this point in time, when the program is still new, OEHHA cannot make definitive conclusions regarding changes in emissions due to the Cap-and-Trade Program that may disproportionately affect disadvantaged communities. OEHHA expects with time the picture will become clearer. As the program continues to generate data over the next several years, it will be easier to detect and evaluate emissions trends. OEHHA intends to update the analysis in subsequent reports as additional types of data and years of data emerge. Co-reporting of high quality data on criteria, air-toxic and GHG emissions for the facilities subject to the Cap-and-Trade Program would substantially aid the investigation of emissions impacts.

In future reports, OEHHA also plans to expand the analysis to cover AB 32 programs in addition to the Cap-and-Trade Program. It will be important to evaluate the Cap-and-Trade Program in concert with other climate policies to gauge how the entire climate change program in aggregate may impact or benefit individual disadvantaged communities and as a whole. Examination of emissions changes in the transportation sector resulting from the large and varied AB 32 programs affecting it will be an important part of this more comprehensive evaluation.

I Introduction

In the ten years since the enactment of the California Global Warming Solutions Act of 2006 (also known as AB 32), concerns have been expressed that the state's trailblazing efforts to reduce greenhouse gas (GHG) emissions may unintentionally impact low-income communities that are already burdened by pollution from multiple sources. A concern is that the state's GHG-reduction programs could prompt regulated businesses to make decisions resulting in higher emissions of conventional air pollutants at facilities in those communities than would otherwise be the case even while statewide GHG emissions decrease.

Conversely, California's climate-change programs also offer the potential to benefit these low-income industrial communities, to the extent that the programs prompt investments by regulated businesses that reduce emissions of both GHGs and conventional air pollutants in the communities where they operate.

In December 2015, Governor Brown directed the California Environmental Protection Agency's Office of Environmental Health Hazard Assessment (OEHHA) to analyze and periodically report on the impacts and benefits on disadvantaged communities related to the state's emission controls to mitigate climate change:

> *"I am directing that the Office of Environmental Health Hazard Assessment (OEHHA) prepare by December 1, 2016, a report analyzing the benefits and impacts of the greenhouse gas emissions limits adopted by the State Air Resources Board pursuant to Division 25.5 (commencing with Section 38500) of the Health and Safety Code within disadvantaged communities described in Health and Safety Code Section 39711. The report shall be made available to the public and the Legislature. OEHHA shall update the report at least every three years.*
>
> *The report, at a minimum, shall track and evaluate (a) greenhouse gas emissions, criteria air pollutants, toxic air contaminants, short-lived climate pollutants, and other pollutant emission levels in disadvantaged communities; and (b) public health and other environmental health exposure indicators related to air pollutants in disadvantaged communities."*

This report is the initial response to this directive. OEHHA has examined readily available information to evaluate possible analytical approaches, and has conducted an initial analysis of one major activity to reduce greenhouse gas (GHG) emissions – the Cap-and-Trade Program. The California Air Resources Board (ARB) established this program in regulation[2] pursuant to

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[2] Originally adopted in 2011. The current Cap-and-Trade regulation can be found at the following URL: https://www.arb.ca.gov/cc/capandtrade/capandtrade.htm.

Health and Safety Code Section 38500 enacted by Assembly Bill (AB) 32 (Núñez, Statutes of 2006), also known as the Global Warming Solutions Act of 2006).

Under the Cap-and-Trade Program, ARB applies a statewide cap on GHG emissions from a number of entities that are responsible for emissions of GHGs. The covered entities represent a variety of industrial sectors. These include electricity generators, food processors, other industrial facilities that burn large quantities of fossil fuels, as well as mobile sources. Facilities are required to surrender state-issued emission allowances and emission offset credits equal to their reported and verified GHG emissions. Over time, the aggregate cap (the total amount of GHG emissions allowed from all covered facilities declines). The regulation provides flexibility in how covered GHG emitters may comply with the overall emissions cap, allowing them to seek the least costly options. Reductions of GHGs may have the added benefit of reducing emissions of toxic air contaminants, ozone-producing gases and criteria air pollutants. The varied distribution on where facilities are located across California and the flexibility of the program can mean that changes in emissions of GHGs do not occur evenly across communities.

A variety of factors in addition to the Cap-and-Trade Program can affect the amount of GHG emitted by a facility including regional or global economic trends and consumer demand, drought, facility shutdowns (e.g., the shutdown of the San Onofre Generating Station) and responses to other policies (e.g., the renewable portfolio standard for electricity generation).

While this initial report focuses on the Cap-and-Trade Program, future reports will also include assessment of other GHG emission reductions programs set in place to meet AB 32 requirements. Some of these other programs are expected to significantly benefit and possibly impact communities' exposures to co-pollutants. These analyses should prove useful for informing future decisions by the state's climate change programs, including mitigating unintended impacts and maximizing benefits from reductions of co-pollutant emissions in disadvantaged communities. However, the Cap-and-Trade Program is still relatively new, with the first auction of emissions instruments occurring in 2013. In these early days of the program, it is hard to discern trends and make firm conclusions regarding patterns of emissions resulting from the program.

This report also highlights the need for data collection practices that would be helpful in enabling ongoing tracking of changes that may be occurring across California communities from the state's efforts to address climate change.

Finally, as described later in this report, GHG, criteria and air-toxic emissions are regulated under different programs. ARB regulates GHG emissions pursuant to AB 32, while local air districts regulate criteria and air-toxic emissions from facilities through their permitting processes. Each of these programs can affect emissions levels of these three classes of pollutants, and make evaluation of emissions of air toxic contaminants and criteria air pollutants that are attributable to the cap-and-trade program challenging.

II Scope of Analysis

This report is directed at the question of whether certain communities, especially disadvantaged communities, are positively or negatively impacted from changes in exposures to environmental pollutants as a result of regulatory responses to the statewide GHG emissions limit adopted pursuant to AB 32. The scope of the analysis is necessarily limited in this initial report because of the limited data currently available, and the relatively short period of time since the implementation of the Cap-and-Trade Program. This section describes some methods that will be used to characterize benefits and impacts of the GHG reduction program, the definition of disadvantaged communities for the analysis, and the GHG reduction program of initial focus.

Benefits and Impacts

For this report, “benefits and impacts” are changes in pollutant exposures in communities resulting from changes in response to the Cap-and-Trade Program. The directive requires that the report, at a minimum, track and evaluate “greenhouse gas emissions, criteria air pollutants, toxic air contaminants, short-lived climate pollutants, and other pollutant emission levels” in disadvantaged communities, and also track and evaluate “public health and other environmental health exposure indicators related to air pollutants” in disadvantaged communities. This report provides information on levels of GHG emissions in communities, while using indicators of levels of criteria air pollutants, toxic air contaminants and other pollutants. Later reports will also identify and track public and environmental exposures indicators as measures of benefits and impacts, and will examine the effects of other GHG reduction programs in addition to the Cap-and-Trade Program. For example, the transportation sector, which is the largest source of GHG, criteria pollutant, and toxic emissions, will be addressed in later reports.

For this first report, we investigate the following emissions in communities:

- Greenhouse gases, including non-CO_2 compounds with global warming potential
- Criteria air pollutants
- Toxic air contaminants

Disadvantaged Communities

The directive requires that benefits and impacts be analyzed within “disadvantaged communities” as described in H&SC Section 39711, established by Senate Bill (SB) 535 in 2012. SB 535 requires the California Environmental Protection Agency (CalEPA) to identify disadvantaged communities for investment of Cap-and-Trade proceeds. These communities are to be identified based on geographic, socioeconomic, public health and environmental hazard criteria, and may include, but are not limited to, either of the following:

(1) Areas disproportionately affected by environmental pollution and other hazards that can lead to negative public health effects, exposure, or environmental degradation.
(2) Areas with concentrations of people that are of low income, high unemployment, low levels of homeownership, high rent burden, sensitive populations, or low levels of educational attainment.

In October 2014, following a series of public workshops to gather public input, CalEPA released its list of disadvantaged communities for the purpose of SB 535. CalEPA based its list on the most disadvantaged communities identified by the California Communities Environmental Health Screening Tool (CalEnviroScreen), a tool developed by OEHHA that assesses all census tracts in California to identify areas disproportionately burdened by and vulnerable to multiple sources of pollution.

The analyses described and presented here focus on those California communities (census tracts) identified in 2014 by CalEPA as disadvantaged using Version 2.0 of the CalEnviroScreen tool.[3] These communities are the highest-scoring census tracts in the state using the results of the tool, and represent about 25% of the state's population (see Figure 1 below).

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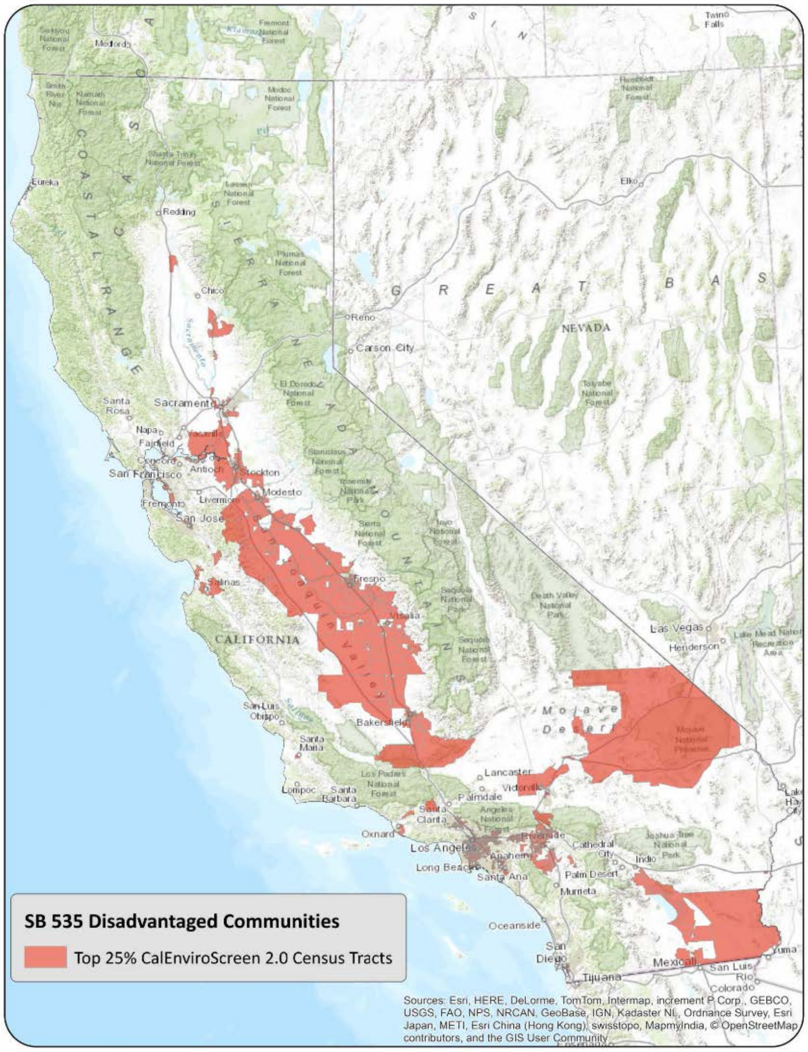
[3] Information on the specific communities/census tracts identified as "disadvantaged" for purposes of SB 535 can be found on CalEPA's website at the following URL: http://calepa.ca.gov/EnvJustice/GHGInvest/.

Figure 1. Communities Identified as "Disadvantaged" under SB 535 (in Red) Using CalEnviroScreen Version 2.0 Results (October 2014).



Sources: Esri, HERE, DeLorme, TomTom, Intermap, increment P Corp., GEBCO, USGS, FAO, NPS, NRCAN, GeoBase, IGN, Kadaster NL, Ordnance Survey, Esri Japan, METI, Esri China (Hong Kong), swisstopo, MapmyIndia, © OpenStreetMap contributors, and the GIS User Community

October 2014

OEHHA updated its statewide analysis of communities with the public release of Version 3.0 of CalEnviroScreen in January 2017. Later in the year CalEPA will make a new identification of "disadvantaged communities" that is expected to rely at least in part on the CalEnviroScreen 3.0 results. Since that new designation has yet to be made, this evaluation of the Cap-and-Trade Program utilizes CalEPA's 2014 designation of disadvantaged communities.

Greenhouse Gas Emissions Limits Adopted by the State Air Resources Board

The directive specifically calls for OEHHA to analyze the benefits and impacts of the greenhouse gas emissions limits adopted by ARB pursuant to AB 32.

AB 32 requires California to reduce its GHG emissions to 1990 levels by 2020. This has been estimated to require a reduction of approximately 15 percent below emissions expected under a "business as usual" scenario. More recently, Senate Bill (SB) 32 (Pavley, Chapter 249, Statutes of 2016) requires ARB to ensure that GHG emissions are reduced to at least 40 percent below the 1990 statewide GHG emissions limit no later than December 31, 2030.

AB 32 requires ARB and other state agencies to adopt regulations to achieve the maximum technologically feasible and cost-effective GHG emission reductions. The goals of AB 32 are also being accomplished through a combination of policies, planning, direct regulations, market approaches, incentives, and voluntary efforts. The full implementation of AB 32 and SB 32 is expected to improve energy efficiency, expand the use of renewable energy resources, and result in cleaner transportation and reduced waste.

ARB's *Climate Change Scoping Plan*, which is required to be updated at least once every five years, describes its strategy for meeting the GHG limits. Its 2014 *Update* described the status of the various measures to reduce GHG emissions.[4] Table 1 below shows a number of the programs that are in place or under development.

Table 1. AB 32-Related Programs and Initiatives to Reduce GHG Emissions.

Economic Activity	Program
Large Industry, Electricity Generators, Fuel Distributors	• Cap-and-Trade Regulation • Energy Efficiency and Co-Benefits Audits for Large Industrial Sectors
Transportation	• Advanced Clean Cars • Low Carbon Fuel Standard • Regional Transportation-Related Greenhouse Gas Targets • Vehicle Efficiency Measures • Ship Electrification at Ports • Cap-and-Trade • Goods Movement Efficiency Measures • Heavy-Duty Vehicle Emission Reduction • Medium- and Heavy-Duty Vehicle Hybridization Voucher Incentive Project • High Speed Rail
Electricity and Natural Gas Use	• Building Energy Efficiency • Appliance Energy Efficiency • Utility Energy Efficiency • Solar Water Heating • Combined Heat and Power Systems • 33 Percent Renewable Portfolio Standard • Senate Bill 1, Million Solar Roofs • Cap-and-Trade

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[4] The 2014 First Update to the AB 32 Scoping Plan, including Appendix B, can be found at the following URL: https://www.arb.ca.gov/cc/scopingplan/document/updatedscopingplan2013.htm.

Economic Activity	Program	
Water Production, Distribution, and Use	- Water Use Efficiency - Water Recycling - Water System Energy Efficiency	- Reuse Urban Runoff - Renewable Energy Production
Green Buildings	- State Green Building Initiative - Green Building Standards Code	- "Beyond Code: Voluntary Programs at the Local Level" - Greening Existing Buildings
Oil and Gas Extraction, Distribution, and Refining	- Oil and Gas Extraction GHG Emission Reduction - GHG Emissions Reduction from Natural Gas Transmission and Distribution - Cap-and-Trade	- Refinery Flare Recovery Process measures, consultation with air districts on amendments to rules for existing leak detection and repair at industrial facilities, including methane leaks
Recycling and Waste Management	- Landfill Methane Control Measure - Increase the Efficiency of Landfill Methane Capture - Mandatory Commercial Recycling	- Increase Production and Markets for Compost and Other Organics, Anaerobic/Aerobic Digestion - Extended Producer Responsibility - Environmentally Preferable Purchasing
Forestry	- Sustainable Forest Target	
Controls on High Global Warming Potential Gases	- Motor Vehicle Air-Conditioning Systems: Reduction of Refrigerant Emissions from Non-Professional Servicing - SF_6 Limits in Non-Utility and Non-Semiconductor Applications - Reduction of Perfluorocarbons in Semiconductor Manufacturing	- Limit Use of Compounds with High Global Warming Potentials in Consumer Products - Stationary Equipment Refrigerant Management Program - SF_6 Lead Reduction Gas Insulated Switchgear

Initial Focus of AB 32 Impact and Benefit Analysis: Cap-and-Trade Program

Many of the AB 32-related GHG emission reduction programs should carry the benefit of reduced exposures to co-pollutants in affected neighborhoods. For example, energy efficiency in electrical power generation and other sectors brings reduced releases of combustion by-products; reduced gasoline use from vehicle efficiency brings lower exposure to a number of gasoline-related toxicants; and improved control of fugitive emissions from natural gas transmission and distribution can reduce benzene releases.

The breadth of activities being undertaken to reduce GHG emissions in California makes a full analysis in this first report of the overall AB 32 program infeasible given the one-year timeframe for conducting the analysis. OEHHA is therefore placing an initial focus on California's Cap-and-Trade Program. This program has been chosen as the initial focus for the following reasons:

- GHG emissions from facilities and sources that are regulated under the Cap-and-Trade Program constitute about 85 percent of the state's GHG emissions.[5]
- Facilities regulated under the Cap-and-Trade Program commonly emit toxic air pollutants in addition to GHGs, and the emissions of GHGs may correlate with toxic co-pollutants. Thus reductions or increases in GHGs may be accompanied by corresponding changes in toxicant emissions.
- Many of the facilities are also located in low-income communities with high non-white populations. An evaluation of this program is consistent with the directive's intent to examine impacts in disadvantaged communities.
- Substantial data describing emissions of GHGs and toxic air contaminants by the covered entities are available.

This initial analysis will become part of a larger ongoing effort to understand the co-benefits and impacts of California's GHG reduction programs. In future reports, OEHHA plans to expand the analysis to cover AB 32 programs in addition to the Cap-and-Trade Program.

The Cap-and-Trade Program

Upon initial implementation in 2012, the Cap-and-Trade Program covered large industrial facilities and electricity generators each annually emitting more than 25,000 metric tons of carbon dioxide equivalent ($MTCO_2e$).[6] Distributors of transportation, natural gas, and other fuels were added to the program beginning in 2015. Presently the program covers about 450 entities.

Facilities in industrial sectors are annually allocated some free allowances to emit a portion of their GHG emissions. An allowance is a tradable permit to emit one metric ton of a CO_2-equivalent greenhouse gas emission (one $MTCO_2e$). Each allowance has a unique serial number to enable its tracking. The initial allocation of allowances for most industrial sectors was set at about 90 percent of average emissions, and was based on benchmarks that reward efficient facilities.[7] A facility's allocation is generally based on its production levels and is updated annually. Utilities that distribute electricity and natural gas are given free allowances whose

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[5] Overview of ARB Emissions Trading Program available at URL: https://www.arb.ca.gov/cc/capandtrade/guidance/cap_trade_overview.pdf.

[6] Carbon dioxide (CO_2) is the primary GHG, but other chemical emissions have global warming potential, including methane (CH_4), black carbon, nitrous oxide (N_2O), and hydrofluorocarbons. Emissions of GHGs are reported as CO_2 equivalents, where emissions rates for GHGs other than CO_2 are adjusted by a multiplier. For example, the multipliers for methane and nitrous oxide are 21 and 310, respectively, indicating higher global warming potential on a mass basis ($CO_2 = 1$).

[7] Overview of ARB Emissions Trading Program. Available at URL: https://www.arb.ca.gov/cc/capandtrade/guidance/cap_trade_overview.pdf.

value must be used to benefit ratepayers and reduce GHG emissions. Electrical distribution utilities also receive an allocation of about 90 percent of average emissions. The allocation for natural gas utilities is based on 2011 levels of natural gas supplied to non-covered entities.

The Cap-and-Trade Program regulations enable trading and limited banking of allowances, as well as obtaining a limited number of “offset” credits. An offset credit is equivalent to a reduction or increase in the removal of one $MTCO_2e$. Offset projects are developed by third parties and have included projects to remove CO_2 from the atmosphere through forestry projects, control of livestock-related biogas emissions, and projects to reduce use of refrigerants. These projects may occur out-of-state.

Allowances and offset credits are together referred to as “compliance instruments.” Regulated entities surrender compliance instruments equivalent to their total GHG emissions by established deadlines within specific compliance periods.[8] Compliance instruments can be obtained from the entity’s free allocation, purchase of allowances at auctions or reserve sales, purchase of offset credits, and transfer of allowances or offset credits between entities. Use of offset credits is limited to up to eight percent of a facility’s compliance obligation. Every year, covered entities turn in allowances and offsets for at least 30 percent of previous year’s emissions.[9]

Under the program, the annual emissions budgets decline 2-3% annually, but emissions in any year can fluctuate somewhat due to banking of allowances and offsets. The “cap” is the sum of the emissions allowances plus the allowable offset in aggregate for the compliance period.

California’s program is designed to be linked to other similar programs outside of the state. This linkage allows covered California entities to use compliance instruments from GHG trading systems outside of California (and vice versa). This linkage creates a larger program and increases the total emission reduction achieved. Since 2014, the state’s program has been linked to the program in Québec, Canada.

The first auction of allowances occurred in November 2012. Compliance obligation began in January 2013. In 2015, the compliance obligation began for distributors of transportation fuels, natural gas, and other fuels.

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[8] The first compliance period was the years 2013 and 2014; the second and third compliance periods are 2015-2017 and 2018-2020, respectively.

[9] At the end of the compliance period, covered facilities must surrender all instruments to cover the remaining emissions, that is 100% of final year and 70% of earlier years.

III Facilities Subject to the Cap-and-Trade Program: Description and Proximity to Disadvantaged Communities

What Are the GHG Facilities?

The Cap-and-Trade Program has required compliance by sources of GHGs that emit more than 25,000 $MTCO_2e$ per year since it began in 2012. These include facilities associated with electricity generation as well as large stationary sources of GHG emissions. Based on industrial classification, ARB has grouped the facilities into broad sectors for reporting purposes. These are: cement plants, cogeneration facilities, electricity generators, hydrogen plants, oil and gas production facilities, refineries, and “other combustion sources.”

For the initial analysis here, OEHHA will continue to use these broad sectors to characterize possible differences in emissions of GHGs and air toxics.

In 2015, the Cap-and-Trade Program incorporated fuel suppliers. These are suppliers of petroleum products (including gasoline and diesel fuel), biomass-derived transportation fuels, natural gas (including operators of interstate and intrastate pipelines), liquefied natural gas, and liquefied petroleum gas. These entities are not included in the current analysis, in part because of how recently they have been included, but also because the emissions of GHGs and air toxics from these entities are distributed too widely to be included in the facility-based analysis conducted for this report. (However, refineries are a point source of emissions and the facility emissions resulting from the production of fuels are included in the analysis.) The current analysis focuses on facilities that produce more localized emissions. Furthermore, the sector representing electricity importers was also excluded from the present analysis.

Table 2 below shows industrial sectors included in the Cap-and-Trade Program, and the amount of GHGs emitted in 2014.[10] The largest contributors are from electricity generation and petroleum and gas refining, which together account for over half of the localized GHG generation covered by the Program (emitter covered emissions). On a facility basis, refineries also dominate, with average facility levels of 1.7 million $MTCO_2e$. However, within all but one sector, there is at least one facility producing more than 1 million $MTCO_2e$.

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[10] Data available pursuant to California’s Regulation for the Mandatory Reporting of Greenhouse Gas Emissions at URL: https://www.arb.ca.gov/cc/reporting/ghg-rep/reported-data/ghg-reports.htm.

Table 2. GHG Emissions in 2014 by Cap-and-Trade Program Industry Sector for Facilities Reporting Emissions (Emitter-Covered Emissions in $MTCO_2e$).

Sector	No. Facilities / Entities	Total $MTCO_2e$ by Sector	Range of $MTCO_2e$ per Facility	Median $MTCO_2e$ per Facility	Mean $MTCO_2e$ per Facility
Cement Plant	9	7,653,163	123 – 1,968,656	935,061	850,351
Cogeneration	48	10,510,133	14,515 – 1,397,718	118,818	218,961
Electricity Generation	81	34,523,656	16 – 2,501,899	133,550	426,218
Hydrogen Plant	7	3,291,235	38,815 – 839,224	615,058	470,176
Oil and Gas Production [a]	50	16,256,368	13,155 – 3,246,254	44,572	325,127
Refinery [b]	18	31,266,353	3 – 6,363,590	1,112,508	1,737,020
Other Combustion Source [c]	116	8,326,559	747 – 1,412,648	44,534	71,781
Total	**329**	**111,827,467**			

[a] Includes eight facilities that also supply natural gas, natural gas liquids, or liquefied petroleum gas.

[b] Includes 15 facilities that also supply transportation fuel or CO_2, and/or operate a hydrogen plant.

[c] Includes one facility that also supplies CO_2.

What Are the Sources of Emissions from GHG Facilities Covered by the Cap-and-Trade Program?

The Cap-and-Trade Program covers several hundred industrial facilities that represent a wide variety of processes and activities. As a result of these activities, GHGs as well as other pollutants are commonly released into the atmosphere.

Table 3 below describes the facility sectors that report GHG emissions under the Cap-and-Trade Program and some of the processes used within these sectors that generate both GHGs and emissions of air toxics. In most sectors, the combustion of fuel is an important contributor to both GHG and air toxics emissions. For some sectors, GHGs are generated from processes other than fuel combustion (for example, CO_2 generated from the production of clinker in the manufacture of cement or CO_2 released from the production of hydrogen gas in the steam reformation process). Nearly all processes also generate air toxics. Criteria air pollutants and toxic air contaminants can be generated by non-combustion processes that may not be related to GHG emissions.

Table 3. GHG- and Air Toxic-Generating Activities and Processes in Primary Sectors of GHG Facilities Covered by the Cap-and-Trade Program (based on 2014 Inventory of Facilities).

Sector	Activities	Processes	Main Processes Generating CO_2e and Air Toxics
Cement Plants	Production of cement from limestone, clay and sand.	The mixture of limestone, clay, and sand is heated at high temperatures in a kiln to form clinker. Clinker is cooled and ground with various additives to produce cement. Key steps: 1. Raw materials acquisition and handling 2. Kiln feed preparation 3. Pyro-processing (calcining) 4. Finished cement grinding Most cement plants use short kilns with preheaters and pre-calciners for pyro-processing in clinker production. Some use long dry kilns without preheaters.	Pyro-processing (calcining) Fuel combustion (frequently coal)
Cogeneration Facilities	Generation of electrical power and useful heat, including waste heat recovery, from the same original fuel energy. Also known as combined heat and power.	Electricity and thermal energy are generated onsite at cogeneration facilities, where waste heat recovery also occurs. Some examples of cogeneration include: 1. Gas or other fuel combustion, sometimes to heat water to produce steam. 2. Gas or steam turbine to generate electricity 3. Exhaust energy convert to steam, exported to a host facility	Fuel combustion (fossil fuels or biomass)
Electricity Generation Facilities	Generating electrical power	1. Gas turbine: fuel combustion to generate electricity 2. Boiler: to capture exhaust heat to make steam 3. Steam turbine: to produce additional electricity	Fuel combustion (fossil fuels or biomass) Fugitive emissions
Hydrogen Plants	Producing hydrogen from feedstock for refineries, food industries, and fertilizer production	Steam methane reforming (SMR) method (for example): 1. Feedstock hydrogenation and sulfur removal 2. Reforming in the SMR 3. Shift conversion 4. Hydrogen purification	Fuel combustion Feedstock consumption[11] All steps

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[11] Produces mainly CO_2.

Sector	Activities	Processes	Main Processes Generating CO_2e and Air Toxics
Oil and Gas Production Facilities	Extraction of crude petroleum and natural gas from geological formations. May include well stimulation such as thermal (steam), waterflood, or gas injection techniques	1. Extraction of oil/water emulsion from the geological formation via a mechanical or submergible pump 2. Separation of emulsion into water, oil, and gas 3. Storage and transfer or oil and water; processing of natural gas for sale or use	Fuel combustion (frequently natural gas for steam generation) Fugitive emissions Flaring Dehydration processes
Refineries	Production of petroleum products, including transportation fuels (gasoline diesel), asphalt, and other products (kerosene, liquefied petroleum gas, feedstock for production of other materials)	Refineries can vary in the complexity of their processes. Topping refineries have small throughput, primarily separating crude oil into intermediates or simple products (e.g., asphalt). Hydro-skimming facilities include reforming and desulfurization process units as well as topping activity. More complex facilities produce transportation fuels and other products, and tend to use more energy, using processes including distillation, reforming, hydrocracking, catalytic cracking, coking, alkylation, blending, isomerization, amine treating, mercaptan oxidation. Many refineries have on-site hydrogen production, calciners, and sulfuric acid plants. Heavy crude oil inputs and production of lighter/cleaner products require more energy.	Combustion of refinery gas, syngas, and petroleum coke Fuel combustion for distillation Hydro-treating Catalytic reforming Sulfur removal Hydrogen generation
Other Combustion Sources	Multiple	Numerous industries are represented by facilities identified under the “other combustion source” sector. Facilities include those that manufacture nitrogenous fertilizer, alcoholic beverages, food and dairy products, paper and paperboard, gypsum products, soda ash, glass and glass containers, milling of iron and steel and rolled steel shapes, forging, lime, and mineral wool. Industrial activities can include canning, secondary smelting, and poultry processing. GHG emissions from colleges, universities, and professional schools are also included in this category.	Industry-dependent

Where Are GHG Facilities?

OEHHA has analyzed the location of 281 GHG facilities covered by the Cap-and-Trade Program for which street addresses could be geocoded from a 2014 inventory of facilities[12]. In this case, the distance from each GHG facility to the nearest SB 535 disadvantaged community was evaluated. Facilities were grouped by industrial sector to determine whether some sectors were more likely to be in or near disadvantaged communities. Facility locations are shown in Figure 2 below. The analysis of the percent of each sector's facilities in or within specific distances of disadvantaged communities is presented in Table 4 below. Since disadvantaged communities represent 25% of the census tracts in the state, Table 4 shows that GHG facilities are disproportionately located within disadvantaged communities for all sectors. Over 50% of facilities for all but the cogeneration sector fall within one-half mile of a disadvantaged community.

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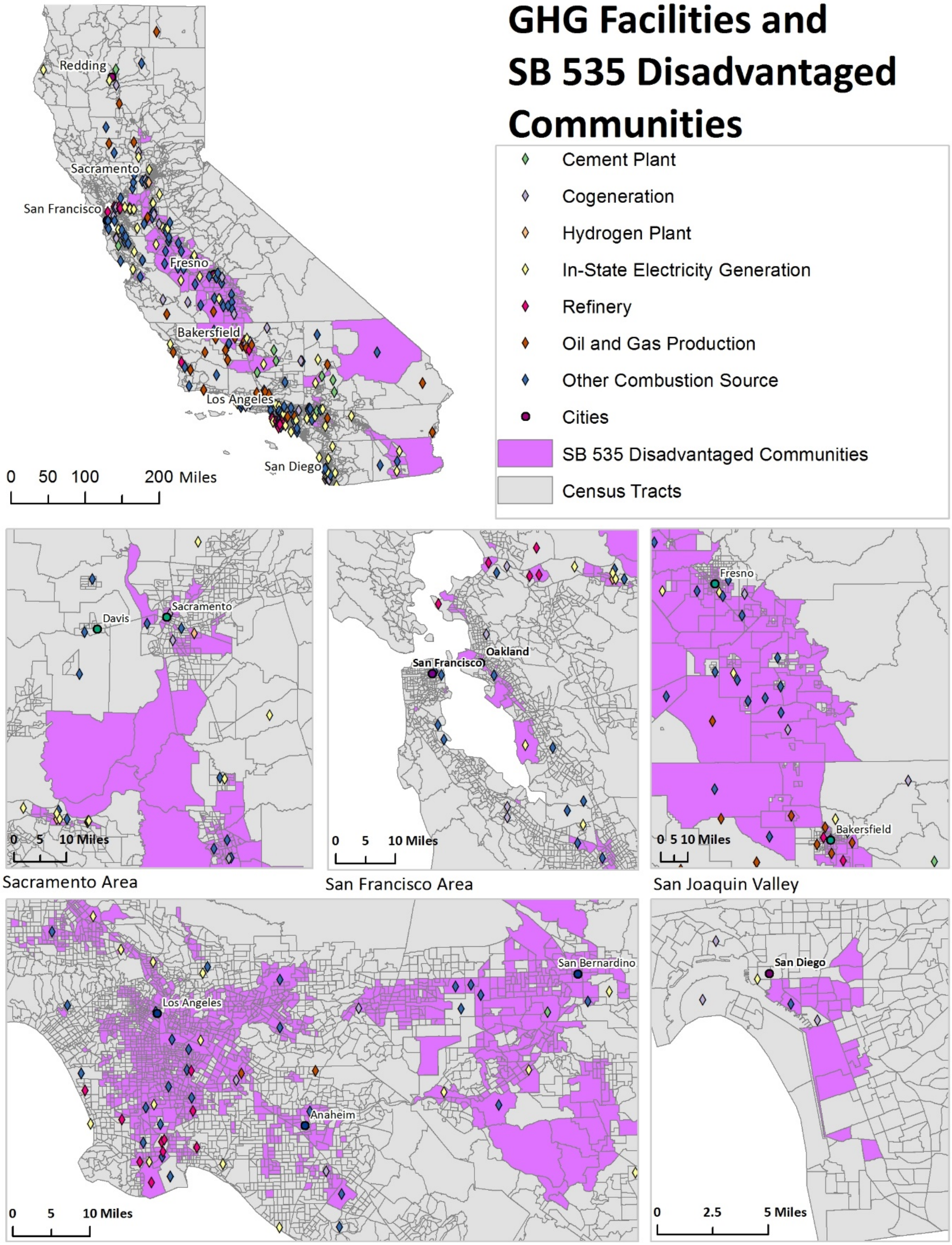
[12] Because oil and gas production facilities can cover large geographic areas, the proximity analysis to disadvantaged communities will require more in-depth spatial analysis. For this reason, 48 oil and gas production facilities with geocoded street addresses are not included in this analysis.

Figure 2. California Map Showing the Locations of GHG Facilities and SB 535 Disadvantaged Communities.



Sacramento Area

San Francisco Area

San Joaquin Valley

Greater Los Angeles Area

San Diego Area

Table 4. Analysis of Proximity of GHG Facilities to SB 535 Disadvantaged Communities (Based on Geocoding by Facility Street Addresses).

Sector	No. Facilities	% of Facilities in or near SB 535 DACs [a]		
		Within	<0.5 mi	<1.0 mi
Cement Plant	9	33	56	56
Cogeneration	59	29	41	42
Electricity Generation	76	41	51	58
Hydrogen Plant	7	43	71	86
Refinery	20	65	75	85
Other Combustion Source	110	56	65	66
Total	281	46	57	60

[a] The SB 535 disadvantaged communities include about 15.5% of California's land area. With the additional 0.5 and 1.0 mile buffers, the land area represents 16.9 and 18.1% of California's land area, respectively. The total land area in California is estimated at 155,779 square miles. Greater buffer distances represent cumulative percent of facilities within a given distance. Facilities are treated here as points. Since many facilities cover large areas (footprint), the proximity to disadvantaged communities may be underestimated in this analysis.

In total, 46 percent of the GHG facilities covered by the Cap-and-Trade Program were located within SB 535 disadvantaged communities, 57 percent were in or within 0.5 miles of one, and 60 percent were in or within one mile of an SB 535 community. Generally, the sectors with the greatest likelihood of having a facility in or near an SB 535 disadvantaged community were from the sectors for refineries, hydrogen plants, and "other combustion source" sectors. Since the majority of GHG facilities are in close proximity to SB 535 disadvantaged communities, changes in emissions generally represent potential for differential increases or decreases in exposure in these communities.

These results are consistent with a recent report from academic researchers that examined the locations of many of the GHG facilities covered under the Cap-and-Trade Program. Cushing *et al.* (2016)[13] describe a geographic analysis of 321 facilities that reported GHG emissions that were covered by the Cap-and-Trade Program during the 2013-2014 compliance period. And of these, 255 were within 2.5 miles of a resident population. Areas in proximity to these facilities

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[13] Cushing LJ, Wander M, Morello-Frosch R, Pastor M, Zhu A, Sadd J (2016). A Preliminary Environmental Equity Assessment of California's Cap-and-Trade Program. Research Brief – September 2016. UC, Berkeley, University of Southern California, San Francisco State University, and Occidental College. Available at URL: http://dornsife.usc.edu/PERE/enviro-equity-CA-cap-trade.

were examined with respect to CalEnviroScreen 2.0 scores (highest 10 and 20% of scores) as well as the percentages of people of color and living in poverty.

The analysis found that census block groups within 2.5 miles of the GHG facilities had higher mean non-white populations, higher mean poverty levels, and a higher likelihood of being in a high-scoring CalEnviroScreen 2.0 census tract compared to block groups farther from GHG facilities. Many block groups are also within 2.5 miles of more than one facility. As the number of facilities near block groups increases, communities tend to have higher populations of color and higher rates of poverty.

IV Proposed Analytic Approach to Characterize Benefits and Impacts

Key Questions

The overall analysis of Cap-and-Trade facilities aims to answer the following key questions, in due course:

- *How do emissions of GHGs relate to emissions of toxic air contaminants and criteria air pollutants from the same GHG facilities?* Since the Cap-and-Trade Program aims to reduce aggregate GHG emissions, understanding how reductions or increases in GHG emissions may relate to changes in emissions of toxic air pollutants that could result in human exposure is critical to analyzing potential benefits and impacts.
- *Are emissions disproportionately occurring in SB 535 disadvantaged communities? Do disadvantaged communities benefit from or are they negatively impacted by changes in emissions from GHG facilities subject to Cap-and-Trade?* The SB 535 communities face burdens from multiple sources of pollution and population vulnerability factors. Equity analyses will address whether changes are occurring that may disproportionately affect these communities.
- *Are the benefits and impacts due to the design of the Cap-and-Trade Program?* The directive seeks to analyze benefits and impacts attributable to the AB 32 program. Therefore, an ultimate goal of the analyses will be to understand what changes in emissions can be attributed to responses to the program rather than external factors, such as economic conditions and drought.

Challenges in Evaluating the Benefits and Impacts of the Cap-and-Trade Program

The ability to examine relationships between Cap-and-Trade Program activities, outputs, and outcomes/impacts is complicated by a number of factors. These include:

- *The diversity of industries and facilities covered by the program.* Uniformity is not expected in how industries are able or likely to achieve compliance with the Cap-and-

Trade Program. The types and amounts of GHG and air toxics emissions that result from changes in industrial activities to comply with Cap-and-Trade are also expected to vary. Thus, the relationships between GHG and co-pollutant emissions vary across different industrial sectors (and even within facilities within a sector) with the differences in fuel types and sources, industrial processes and chemical feedstocks. For example, certain industrial processes may require fuels that burn at high temperatures. The emissions profile (specific chemicals emitted and levels at which they are emitted) typically varies with the temperature of combustion. Alternative fuels can also have different emissions profiles from conventional fuels.

- *The limited availability of data about GHG program activities, associated emissions, and health and other outcomes.* Some information regarding program activities is limited due to the need to protect confidential business information and market sensitivity of the information. This information could inform analyses of the relationship between GHG and co-pollutant emissions and facilities. Possible examples of such information include the mix and quantity of products made at specific facilities, and emissions produced per unit of product manufactured at a facility. However, such information may potentially provide economic advantage to competitors if made publicly available.

  Other limitations in data are that information relevant to the analysis of outcomes – especially co-pollutants – has not to date been required to be co-reported with GHG emissions. As a result, these data must be obtained from sources resulting from other federal, state and local regulatory programs, such as permitting and reporting requirements and emissions monitoring by local air districts. Differences in reporting requirements across regulatory programs can complicate the analysis. Optimally, this analysis would have data reporting for co-pollutants and GHG emissions within the same time period, and over time. Changes in data collection practices can make it difficult to establish relationships between activities and outcomes over time.
- *The flexibility of the Cap-and-Trade Program.* The program has a number of components, including the aggregated nature of the GHG emissions cap and provisions to minimize “leakage” in which economic/industrial activity may move out of state. Facilities are also provided with numerous options for how compliance can be achieved, including “banking” of compliance instruments to provide flexibility while the program overall still meets the goals of GHG emission reductions. Also, the phase-in of different industrial sectors has occurred in different years.
- *Confounding factors that affect emissions and related outcomes that are unrelated to the Cap-and-Trade Program*. As one important example, industrial activity in California is affected by the overall economy and market factors, and may also be affected by other state, regional, or local regulatory activity. This can influence levels of GHG and air toxics

emissions. For example, the US and California experienced a severe economic recession from the late 2000s into the early 2010s, followed by an economic recovery, which occurred in the same period over which the Cap-and-Trade Program was launched and has developed. Another example includes the recent and persistent California drought. Because a large fraction of the state's electricity supply is derived from hydropower, the recent drought has necessitated additional generation of electricity from thermal power plants. Further, during the analysis period, the San Onofre Generating Station (a large nuclear power plant) was decommissioned. This resulted in more in-state emissions than would otherwise have occurred due to electricity generation from thermal power plants.

Practical Steps for Initial Analysis

Limitations to the readily available data place some constraints on the initial analysis described here. More public data are available to describe potential overall changes in pollutant emissions in disadvantaged communities than are available to specifically characterize Cap-and-Trade Program activities that may be influencing those emissions changes (see Section V below). For this reason, OEHHA is first examining the emissions data, and later intends to identify potential regulatory activities that may be contributing to changes in emissions, especially in disadvantaged communities. This report focuses on identifying and describing relevant data sources and how they can be used, gathers readily available data, and presents initial findings regarding those data.

V Data Used to Characterize Emissions of GHG and Air Toxics Emissions from GHG Facilities

Various types of information are collected by state and federal agencies on emissions of GHGs and toxic air pollutants from facilities and other entities covered by the Cap-and-Trade Program. Below are the sources of information that provided emissions data for the analysis of impacts and benefits of California's Cap-and-Trade Program described in this report.

Mandatory Reporting of Greenhouse Gas Emissions

GHG emissions must be reported to ARB annually by many industrial sources, fuel suppliers, and electricity importers under the Mandatory Reporting Rule (MRR).[14] Of these

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[14] More detailed information on Mandatory Greenhouse Gas Emissions Reporting is available from ARB's website at URL: https://www.arb.ca.gov/cc/reporting/ghg-rep/ghg-rep.htm.

facilities/entities, many are also subject to the Cap-and-Trade Program. For such facilities, the submitted emissions data are verified by an accredited third party. The table below describes some of the publicly available data through the MRR.

Table 5. Partial List of Information Available from Mandatory Greenhouse Gas Emissions Reporting.

Source of Information	Description of Available Data
Facility Data	• Facility name, ARB identification code, ZIP Code/city, industrial sector, industrial classification code (NAICS)
Total Emissions	• Total CO_2e from combustion, process, vented, and supplier (in $MTCO_2e$); includes both fossil and biomass-derived fuels
Facility Reported GHG Data (in $MTCO_2e$)	• CO_2e from non-biogenic sources and CH_4 and N_2O from biogenic fuels[15] as emitters and fuel suppliers • CO_2e from biogenic fuels as emitters and fuel suppliers • Electricity importer CO_2e
ARB Calculated Covered Emissions (in $MTCO_2e$)	• Covered emissions as emitters, fuel suppliers, and electricity importers • Total covered emissions (combined for entities with multiple) • Total non-covered emissions

ARB has publicly provided information on GHG emissions for each year since 2008. However, emissions data for the years 2008 to 2010 are not directly comparable to later years. This is a result of changes in methodology to harmonize with U.S. EPA's GHG reporting regulation. An additional industrial sector has also been brought into the program since GHG reporting began, namely fuel distributors.

In 2015, GHG emissions data were reported for over 800 facilities, 724 of which reported GHG emissions greater than zero. The number of facilities in sectors expected to have on-site emissions was 589 (excluding electricity importers and suppliers of natural gas and transportation fuel). Not all facilities that report GHG emissions under the MRR are required to participate in the Cap-and-Trade Program.

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[15] Biomass fuels are derived from biomass products and byproducts, wastes, and residues from plants, animals, and microorganisms. Emissions from combustion of biomass fuels that meet certain criteria are considered biogenic and are exempt from a compliance obligation in the Cap-and-Trade regulations.

ARB also provides data related to how each entity covered by the Cap-and-Trade regulation meets it compliance obligation in terms of the total number of allowances and offsets surrendered each year.[16]

Table 6. Information Available in the Annual Compliance Report for the Cap-and-Trade Program (ARB).

Type of Information	Description of Available Data
Facility information	Facility name and ARB identification number
Compliance Instrument Data	• 2013-2014 triennial surrender obligation • Total instruments surrendered • Total allowances surrendered • Offsets surrendered and the types of offset credits and specific offset projects those credits are from • Compliance status ("fulfilled" or "unfulfilled")

The Cap-and-Trade Program has established definitions of "facility" that clarify the extent of facilities operations that are required to report as a single entity. These definitions are provided in Appendix A.

Air Toxics "Hot Spots" Emission Inventory

Information on emissions of toxic substances from facilities in California is available from the Air Toxics "Hot Spots" Emissions Inventory. Emissions inventory plans are intended to provide "a comprehensive characterization of the full range of hazardous materials that are released, or that may be released, to the surrounding air from the facility" and includes all continuous, intermittent, and predictable air releases (Health and Safety Code section 44340(c)(2)). The Air Toxics "Hot Spots" Information and Assessment Act of 1987 (Health and Safety Code section 44300-44394, as amended) requires reporting of site-specific emissions of toxic substances based on criteria and guidelines adopted by ARB.[17] These guidelines outline:

- *The facilities that are subject to reporting.* Generally, any facility[18] or business in California that emits more than 10 tons per year of organic gases, particulate pollution, nitrogen oxides, or sulfur oxides, is subject to "Hot Spots" requirements. Certain smaller

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[16] This information is made available through ARB's website at URL: https://www.arb.ca.gov/cc/capandtrade/capandtrade.htm (see Publicly Available Market Information).

[17] AB 2588 Air Toxics "Hot Spots" Emission Inventory Criteria and Guidelines Regulation (Guidelines). The current regulation and a detailed description of the guidelines are available on ARB's website at https://www.arb.ca.gov/ab2588/2588guid.htm#current.

[18] See Appendix A for definition of "facility" under this program.

facilities like gas stations, dry cleaners, and chrome platers are also subject to the requirements. Some “low level” facilities are exempt from further update reporting unless specified reinstatement criteria are met. Reductions in emissions from changes in activities or operations may also exempt some facilities from further reporting requirements. Facilities that have been exempted from compliance with this program may also be reinstated under certain conditions (for example, emissions of a newly listed substance, the establishment of a nearby sensitive receptor such as a school, or an increase in the potency of a substance that it emits).

- *The groups of substances to be inventoried.* Different chemical substances have different reporting requirements. Emissions must be quantified for over 500 specific substances. Production, use, or other presence must be reported for an additional ~200 substances. Facilities must report whether they manufacture an additional ~120 substances.
- *When facilities are required to report.* This is based on prioritization scores, risk assessment results, or *de minimis* thresholds. Emissions inventories developed under the “Hot Spots” Program are updated every four years.
- *The information a facility operator must include in a facility's update to their emission inventory.*
- *Criteria by which “Hot Spots” reporting is integrated with other air district programs.*
- *The information that must be included in the air toxics emission inventory plan and report by a facility operator.*
- *The source testing requirements, acceptable emission estimation methods, and reporting formats.*

Criteria Air Pollutant Emissions

Emissions data for criteria air pollutants from California facilities are collected by county or regional air districts as a result of both state and federal laws. The district data are then reported to ARB. Generally, large facilities report these emissions annually, though facilities with lower rates of emissions may only be required to report every three years.

Data on the emissions of criteria air pollutants for some facilities that are subject to the Cap-and-Trade regulation have recently been made available on ARB’s Integrated Emissions Visualization Tool.[19] This includes data by facility for the years 2008 to 2014 on emissions of

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[19] Available at URL: https://www.arb.ca.gov/ei/tools/ievt/. For additional information comparing the reporting of GHG and criteria air pollutant emissions, see also URL: https://www.arb.ca.gov/ei/tools/ievt/doc/ievt_notes.pdf.

ozone-producing volatile organic compounds (VOCs), nitrogen oxides (NOx), sulfur oxides (SOx), particulate matter (PM 2.5 and PM10), and ammonia (NH_3).

Toxic Release Inventory (TRI; US Environmental Protection Agency)

Another source of emissions data for toxic substances is the US Environmental Protection Agency's (US EPA) Toxic Release Inventory (TRI).[20] Under this program, facilities[21] in certain industrial categories with more than 10 full-time equivalent employees that manufacture, process, or otherwise use chemicals are required to report chemical emissions. Industries covered include certain electric power utilities, chemical manufacturing, mining, hazardous waste treatment, and federal facilities.

The list of chemicals for which reporting is required currently contains almost 600 individual chemicals, plus 31 chemical categories. Facilities are required to report emissions that manufacture or process more than 25,000 pounds, or otherwise use more than 10,000 pounds of any listed chemical in the course of a calendar year. Lower thresholds are in place for facilities that manufacture, process, or use certain persistent bioaccumulative toxic (PBT) chemicals.

For industries and facilities required to report, the minimum amounts that must be reported are on the order of 0.1 to 1 pounds per year. Reporting levels for PBT chemicals have no minimum levels. For qualifying facilities, reporting occurs annually.

General Limitations to the Use of Emissions Data as an Indicator of Benefits and Impacts

Emissions data are being used in this report as a proxy for potential exposures to air pollutants that arise from industrial sources, and do not directly correspond to health risks to individuals in communities near facilities. Health risks are typically estimated through health risk assessments of the facilities themselves. Such assessments can take into account a large number of factors, such as: the specific location of the emissions, the fate and transport of the substances emitted (in consideration of stack height, meteorology and terrain), the estimated concentrations of chemicals where people are, the duration of exposures, and the toxicity characteristics of the substances informed by health guidance values (such as cancer potencies and reference exposure levels). However, for an initial screen of potential concerns related to emissions of toxic air pollutants, emissions data provides information to use as a basis for

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[20] Section 313 of the Emergency Planning and Community Right-to-Know Act (EPCRA, or Title III of the Superfund Amendments and Reauthorization Act of 1986, Public Law 99-499). Additional information available through U.S. EPA's website at URL: https://www.epa.gov/toxics-release-inventory-tri-program.

[21] See Appendix A for definition of "facility" under this program.

relative comparison (changes in emissions) and can illuminate the nature of potential hazards arising from facilities.

To address variations in the toxicity of the emitted chemicals, this report performs a toxicity weighting of the emitted chemicals. This weighting puts a greater emphasis on the more highly toxic emitted chemicals than on emitted chemicals with relatively low toxicity.

There are uncertainties associated with emissions data themselves. While the emissions reporting described below is required by law under different statutes, the amounts and types of emissions are self-reported by the regulated industries. This means they may be subject to some reporting errors. Different regulatory programs have different practices in place to verify submitted data, though there may be inaccuracies that are difficult to identify. Reporting requirements can change over time to include additional types of emissions and emission processes. Factors that are used to estimate emissions from specific processes can also be revised over time, leading to changes in the estimates.

VI Toxicity of GHGs and other Air Pollutants

Greenhouse Gases

There is generally low concern for human health from localized emissions of carbon dioxide (CO_2), the primary GHG that is driving climate change. Only at very high concentrations does CO_2 affect human health. For this reason, emissions of CO_2 itself are not considered to be contributing to localized impacts from facilities where it is emitted.

Other GHGs are the “short-lived climate pollutants” including methane, fluorinated gases, and black carbon. Methane is more potent than CO_2 as a GHG, but is generally emitted at lower rates than CO_2. Sources of methane include agriculture, the oil and gas industry, and from the treatment of waste. Methane is generally not expected to have health effects from localized emissions due to its low toxicity.

Fluorinated gases include chlorofluorocarbons, hydrochlorofluorocarbons, and hydrofluorocarbons, many of which are being phased out of use because of their ozone-depleting potential. Most of the emissions of this class of compound arise from leakage of refrigeration systems. As such, they provide a relatively limited contribution to emissions from facilities regulated under the Cap-and-Trade Program. Similarly, sulfur hexafluoride has numerous uses, but is regulated from early actions outside of the Cap-and-Trade Program due to its very high global warming potential and increasing levels in recent years.

Black carbon is generally created as a product of incomplete combustion of organic fuels, including diesel fuels. Black carbon is a component of particulate pollution (including PM2.5, see below) and diesel particulate matter, both of which have well-described human health toxicity concerns, including increasing risk of premature death and cancer. California has substantially reduced black carbon from diesel exhaust from many sources over the past 20 years, corresponding to a 13% reduction in the total annual CO_2 emissions in California.

Criteria Air Pollutants

The criteria air pollutants are common air pollutants for which federal standards are established under the Clean Air Act (42 U.S. Code Chapter 85). The six criteria air pollutants are ozone, particulate matter, sulfur dioxide, nitrogen dioxide, carbon monoxide, and lead. California has established more protective standards in some cases. The standards are established to protect even the most sensitive individuals, such as children and elderly. Some of the common sources of exposure and key health effects are described in Table 7 below.

Table 7. Sources of Exposure and Health Effects of Criteria Air Pollutants.

Criteria Air Pollutant	Sources of Exposure	Health Effects
Ozone	Generated from interaction of sunlight with volatile organic compounds (reactive organic gases), especially hydrocarbons, and nitrogen oxides; ozone formation may be distant from the source of these emissions. Sources include vehicles, industrial facilities, and consumer products, among others.	Damage to the respiratory tract; worsening of symptoms for respiratory diseases like asthma, bronchitis, and emphysema; reduction in lung function; increased susceptibility to infections. People who spend more time outdoors may be especially susceptible.
Particulate matter (PM)	Many sources of PM; generated by the combustion of most fuels, which produces most of fine PM (particles less than 2.5 microns in diameter, PM2.5); larger particles (PM10) can be generated by blowing dusts. Particles can vary greatly in their composition.	Worsening of heart and lung disease; decreases in lung function and respiratory symptoms, such as coughing or shortness of breath; increases in hospitalizations and deaths. People with heart and lung disease, as well as children and elderly, may be especially susceptible to the effects.

Criteria Air Pollutant	Sources of Exposure	Health Effects
Sulfur dioxide	Combustion of fuel containing sulfur. Industrial sources include certain petroleum refining processes. Other sources are locomotives, ships, and certain diesel equipment.	Respiratory effects include shortness of breath and wheezing. Increases in mortality have been observed from sulfur dioxide exposure. Children, elderly, asthmatics, and people with existing heart disease may be especially sensitive to the effects.
Nitrogen dioxide	Combustion of fuel by cars, trucks, and at power plants.	Damage to the respiratory tract. Asthmatics may be especially susceptible to the harmful effects of nitrogen dioxide exposures.
Carbon monoxide	Produced from the incomplete combustion of fuels from a variety of sources.	Dizziness and confusion at high levels of exposure, though unlikely outdoors. Individuals with heart or lung disease may be especially susceptible.
Lead	Multiple sources, especially processing of metals, waste incineration, battery manufacturing, and aircraft burning leaded aviation fuel.	Harmful to the nervous, cardiovascular, immune, reproductive and developmental systems. Children are especially sensitive to the effects of lead.

Toxic Air Contaminants

"Toxic air contaminants" are defined in California law as air pollutants which may cause or contribute to an increase in mortality or in serious illness, or which may pose a present or potential hazard to human health (Health and Safety Code section 39655). There are currently almost 200 substances or groups of substances identified as toxic air contaminants by ARB.[22] These substances show a wide range of toxicity characteristics and physical properties that could influence the likelihood of health effects if they are emitted to air.[23]

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[22] The current list can be found on the ARB website at URL: https://www.arb.ca.gov/toxics/quickref.htm#TAC.

[23] Information on the types of hazards for many identified toxic air contaminants is available at URL: https://www.arb.ca.gov/toxics/cattable.htm.

Some toxic air contaminants were listed because they were federally designated hazardous air pollutant (pursuant to subsection (b) of Section 112 of the federal act (42 U.S.C. Sec. 7412(b)). ARB designated others based on evaluations performed by OEHHA that meets specific criteria described in California law (Health and Safety Code section 39660).

VII Results

Toxicity-Weighted Emissions to Air

Most GHG facilities covered by the Cap-and-Trade Program emit a combination of GHGs, criteria air pollutants, and toxic air contaminants. While GHGs themselves tend to be relatively less toxic, co-pollutants that are emitted can vary significantly by facility with respect to their composition and potential toxicity. To provide additional information on how these facilities vary with respect to overall toxicity of emissions, OEHHA derived a “toxicity-weighted” emissions score for each of the facilities for which emissions data were available. The purpose of this analysis was to screen for higher-concern facilities with respect to emission levels and potential chemical toxicity.

The data were derived from the California Air Toxics “Hot Spots” Emissions Inventory for GHG facilities that could be matched across both the “Hot Spots” and Cap-and-Trade Programs. This matching was performed by investigators from UC Berkeley and San Francisco State University. The facility matching involved geocoding facility addresses that were available for each Cap-and-Trade Program GHG facility. The location information was then matched to location information for “Hot Spots” facilities that was made available by ARB. Facilities with close proximity to a listed address and similar facility names were presumed to match. Comparable identities were confirmed by visual inspection of satellite imagery and internet research. In developing this facility data set, some facility locations were adjusted so that they more closely spatially aligned with likely point sources of emissions.

There are several uncertainties associated with the matching of Cap-and-Trade and “Hot Spots” facilities due to the differences between the two regulatory programs. These uncertainties come from differences in how facilities are defined under each program. In some cases, facilities may have multiple operations that are combined for the purpose of reporting GHG emissions. However, these operations may be reported separately for air toxics and criteria air pollutant emissions.

Of the full set of Cap-and-Trade covered facilities from sectors that were expected to produce localized emissions, a subset of 374 facilities were tentatively identified as likely matches to “Hot Spots” facilities. Emissions information for 365 of these facilities was provided to OEHHA by ARB for the 2014 reporting year. These data included annual emissions amounts for individual criteria air pollutants (or their precursors for those with ozone-forming potential) and individual chemicals for which reporting is required under the “Hot Spots” Program. A smaller subset of 77 facilities had risk assessments prepared under the “Hot Spots” Program. In these cases, emissions were modeled to identify potential risks in neighboring communities. Since these data were somewhat limited in availability across Cap-and-Trade Program covered facilities, they are not currently being used in the analysis described here.

Because facilities emit multiple chemicals and not all chemicals are equally toxic, OEHHA applied weighting factors to the air toxics emissions data for each facility. OEHHA calculated a toxicity-weighted emissions score for each of the 365 facilities using an approach comparable to that used to calculated toxicity-weighted emissions under US EPA’s Toxic Release Inventory Program. To apply a comparable methodology here, US EPA’s Inhalation Toxicity Scores for individual chemicals were matched and applied to the chemical emissions levels for air toxics (pounds emitted per year) from each facility.[24] Some chemicals whose emissions are required to be reported in the “Hot Spots” Program did not have US EPA toxicity weights available. These compounds are currently excluded from the analysis. Toxicity weights may be established for these compounds in the future.

Toxicity weight is described by US EPA as follows: [25]

> *“This weight is a proportional numerical weight applied to a chemical based on its toxicity. The toxicity of a chemical is assessed using EPA-established standard methodologies. For each exposure route, chemicals are weighted based on their single, most sensitive adverse chronic human health effects (cancer or the most sensitive noncancer effect). In the absence of data, the toxicity weight for one pathway is adopted for the other pathway. The range of toxicity weights is approximately 0.02 to 1,400,000,000.”*

This type of weighting was also used in characterizing air toxics emissions in the California Communities Environmental Health Screening Tool (CalEnviroScreen). Toxicity weights do not include the criteria air pollutants (NO_x, PM2.5, etc.). Those pollutants are evaluated separately below.

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[24] OEHHA used US EPA values here because they were readily available. Since California-specific risk and toxicity data may be available for many chemicals, these values will be updated for future analyses. As an example, US EPA does not include a toxicity weight for diesel exhaust, which can be an important contributor to cancer risk from facilities.

[25] Further information is available on U.S. EPA’s website at URL: https://www.epa.gov/trinationalanalysis/hazard-and-risk-tri-chemicals-2014-tri-national-analysis.

As discussed above, the toxicity weights themselves for each compound are not a measure of risk or likelihood of harm, but provide a way to screen overall emissions from facilities that allows comparisons and the identification of those emissions of highest overall concern.

The emissions characteristics of facilities differ by industry. Using the information on emissions reported by facilities, the most frequently reported specific chemical emissions are described in Table 8 below. Across sectors, numerous air toxics are reported to be emitted that are commonly created by fuel combustion. These include formaldehyde, benzene, toluene, xylenes, 1,3-butadiene, diesel particulate matter, and polycyclic aromatic hydrocarbons (PAHs). The composition of chemicals emitted from fuel combustion depends on the type of fuel burned (oil, coal, natural gas, biomass). Other emissions are likely to be associated with a type of industry. For example, nearly all cement plants report emissions of nickel, naphthalene, lead, formaldehyde, hexavalent chromium, cadmium, beryllium, benzene, and arsenic. (One cement plant in this data set reported very low activity in 2014 with respect to both GHG and air toxics emissions.) Oil and gas production facilities emit numerous organic chemicals: benzene, formaldehyde, naphthalene, toluene, xylenes, acetaldehyde, PAHs, acrolein, ethylbenzene, and 1,3-butadiene.

Toxicity-weighted emissions values were calculated for each of the facilities for which air toxics emissions data were available, as described above. The highest-scoring 25 facilities are presented in Table 9 below. While multiple sectors are represented in this group, some sectors appear more frequently among those with the highest toxicity-weighted emissions. The highest-scoring 25 facilities in the state include several cement plants (6), refineries (6), and facilities associated with oil and gas production (6).

Table 8. Frequency of Specific Chemical Emissions for Facilities with Reported Air Toxics Emissions by Cap-and-Trade Sector (Criteria Air Pollutants Excluded).

Sector	Facilities*	Chemicals most frequently reported emitted (number of occurrences) *
Cement Plants	9	Nickel (8) Naphthalene (8) Lead (8) Formaldehyde (8) Hexavalent chromium & compounds (8) Cadmium (8) Beryllium (8) Benzene (8) Arsenic (8) Selenium (7) Mercury (7) Manganese (7) Copper (7) Zinc (6) Xylenes (mixed) (6) Toluene (6) Hydrochloric acid (6) Chromium (6) Benzo(a)pyrene (6) Acetaldehyde (6) 2,3,7,8-Tetrachlorodibenzo-p-dioxin (6) 1,3-Butadiene (6) Silica, crystalline (respirable) (5) Indeno(1,2,3-cd)pyrene (5) Ethyl benzene (5) Dibenz(a,h)anthracene (5) Benzo(k)fluoranthene (5) Benzo(b)fluoranthene (5) Benz(a)anthracene (5) 2,3,7,8-Tetrachloro-dibenzofuran (5) 2,3,4,7,8-Pentachloro-dibenzofuran (5) 1,2,3,4,6,7,8-Heptachloro-dibenzo-p-dioxin (5) 1,2,3,4,6,7,8-Heptachlorodibenzofuran (5)

Sector	**Facilities***	**Chemicals most frequently reported emitted (number of occurrences) ***
Cogeneration Facilities	48	Formaldehyde (43) Benzene (43) Toluene (35) Ammonia (34) Naphthalene (31) Acetaldehyde (29) Xylenes (mixed) (27) Acrolein (26) 1,3-Butadiene (26)
Electricity Generation Facilities	90	Formaldehyde (80) Benzene (80) Ammonia (71) Naphthalene (60) 1,3-Butadiene (50) Toluene (47) Arsenic (46) Nickel (45) Lead (45) Cadmium (45) Hexavalent chromium & compounds (40) Xylenes (mixed) (39)
Hydrogen Plants	6	Formaldehyde (6) Benzene (6) Ammonia (5) PAHs, total (4) Naphthalene (4)
Oil and Gas Production Facilities	47	Benzene (40) Formaldehyde (38) Naphthalene (32) Toluene (28) Xylenes (mixed) (25) Acetaldehyde (25) PAHs, total (24) Acrolein (24)
Refineries	20	Ammonia (19) Benzene (18) Formaldehyde (17) Nickel (16) Lead (16) Hexavalent chromium & compounds (16) Cadmium (16) Naphthalene (15) Arsenic (14) Beryllium (13) 1,3-Butadiene (13) PAHs, total (12)

Sector	Facilities*	Chemicals most frequently reported emitted (number of occurrences) *
Other Combustion Sources	114	Numerous industrial activities are represented in the "Other Combustion Sources" category. A few examples are presented below. **Fruit and Vegetable Canning** Toluene (8) Formaldehyde (8) Benzene (8) Xylenes (mixed) (6) Propylene (6) Nitrous oxide (6) Naphthalene (6) Methane (6) Hexane (6) Ethyl benzene (6) Carbon dioxide (6) Acrolein (6) Acetaldehyde (6) PAHs, total (5) Ammonia (5) Diesel engine exhaust, particulate matter (Diesel PM) (4) **Dry, Condensed, and Evaporated Dairy Product Manufacturing** Diesel engine exhaust, particulate matter (Diesel PM) (5) Xylenes (mixed) (4) Toluene (4) Propylene (4) PAHs, total (4) Nitrous oxide (4) Naphthalene (4) Methane (4) Hexane (4) Formaldehyde (4) Ethyl benzene (4) Carbon dioxide (4) Benzene (4) Acrolein (4) Acetaldehyde (4) **Paperboard Mills** Formaldehyde (3) Benzene (3) Toluene (2) Nickel (2) Naphthalene (2) Lead (2) Hexavalent chromium & compounds (2) Cadmium (2) Arsenic (2) Ammonia (2) Acetaldehyde (2) **Colleges, Universities, and Professional Schools** Formaldehyde (8) Benzene (8) Nickel (7) Lead (7) Hexavalent chromium & compounds (7) Cadmium (7) Arsenic (7) Naphthalene (6) Mercury (6) Toluene (5) Methylene chloride (5) Manganese (5) 1,3-Butadiene (5) Xylenes (mixed) (4) Acrolein (4) Acetaldehyde (4)

* Facility count is the number of facilities for which air toxics emissions data are available, but did not report emitter-covered GHG emissions in 2014.

Table 9. Twenty-Five Cap-and-Trade Facilities with the Highest Toxicity-Weighted Air Emissions.* Shaded Facilities Are In or Within ½ Mile of an SB 535 Census Tract.

Facility Name and Approximate Location	Sector	Tox-Weighted Air Emissions	CEIDARS ID	ARB ID
CalPortland Company, Mojave Plant, Mojave	Cement Plant	11,128,486,856	15_KER_9	101029
California Resources Elk Hills, LLC, 35R Gas Plant, Tupman	Oil & Gas Production, Supplier of NG/ NGL/ LPG	8,019,256,117	15_SJU_2234	104014
Riverside Cement Company, Oro Grande	Cement Plant	4,773,322,002	36_MOJ_1200003	100013
Cemex Construction Materials Pacific LLC, Victorville Plant	Cement Plant	3,981,635,547	36_MOJ_100005	101476
Lake Shore Mojave, LLC (Shutdown), Boron	Cogeneration	3,154,251,353	KER_593	100218
U.S. Borax, 93516, Boron	Other Combustion Source	3,154,251,353	15_KER_28	100300
PG&E Hinkley Compressor Station, Hinkley	Oil & Gas Production	2,695,090,703	36_MOJ_1500535	101290
Lehigh Southwest Cement Co., Tehachapi	Cement Plant	2,565,789,410	15_KER_20	101461
Mitsubishi Cement 2000, Lucerne Valley	Cement Plant	2,073,213,791	36_MOJ_11800001	101010
Shell Oil Products US, Martinez	Refinery, Hydrogen Plant	1,916,625,223	7_BA_11	100914
PG&E Topock Compressor Station, Needles	Oil & Gas Production	1,576,205,185	36_MOJ_1500039	101031
ExxonMobil Oil Corporation, Torrance Refinery Torrance	Refinery, Hydrogen Plant, CO_2 Supplier	1,531,495,371	19_SC_800089	100217
Searles Valley Minerals Inc., Trona	Other Combustion Source	1,487,264,625	36_MOJ_900002	100011
Southern California Gas Co., South Needles Facility, Needles	Oil & Gas Production	1,401,623,408	36_MOJ_3100068	101346
Coso Power Developers (Navy II), Geothermal, Little Lake	In-State Electricity Generation	1,280,562,586	15_KER_328	101669
National Cement Company, Lebec	Cement Plant	1,151,169,990	15_KER_21	101314
Freeport-McMoRan Oil & Gas LLC, SJV Basin Facility, Fellows	Oil & Gas Production	1,090,450,784	15_SJU_1372	104081
Imerys Minerals California, Inc., Lompoc	Other Combustion Source	1,047,824,807	42_SB_12	101318
Grayson Power Plant, Glendale	In-State Electricity Generation	873,364,347	19_SC_800327	100181
Valero Refining Company, Refinery and Asphalt Plant, Benicia	Refinery, Hydrogen Plant, CO_2 Supplier	830,573,455	48_BA_12626	100372
Tesoro Refining and Marketing Co., Martinez	Refinery, Hydrogen Plant, CO_2 Supplier	786,966,781	7_BA_14628	101331
Southern California Gas Co - Aliso Canyon Facility, Northridge	Oil & Gas Production	716,224,953	19_SC_800128	101349
Spreckels Sugar Company, Inc., Brawley	Other Combustion Source	708,360,193	2014_13_IMP_10	101241
Chevron Products Company, El Segundo	Refinery, Hydrogen Plant, CO_2 Supplier	697,864,142	2014_19_SC_800030	100138
Phillips 66 Company, Los Angeles Refinery, Wilmington	Refinery, Hydrogen Plant, CO_2 Supplier	673,822,489	2014_19_SC_171107	100329

*Top 25 of the 297 facilities for which scores could be calculated using 2014 emissions data.

Air Toxics and GHGs Emissions

Plotting data graphically for visual inspection and calculation of correlation coefficients are approaches to the evaluation of data that may be informative with respect to relationships between greenhouse gas emissions and toxic air contaminants.

The Pearson correlation coefficient is a measure of the linear dependence between two variables, in this case between GHG emissions and a number of different pollutant emission measures. A Pearson correlation coefficient is high when the relationship between two measures increases linearly in proportion to each other. Generally, high positive correlation produces a coefficient r-value of greater than 0.8, with moderately high correlation above 0.5, moderate when the measures are between 0.3 and 0.5, and low when below 0.3 to zero but statistically significant. Inversely correlated values are negative. The Pearson correlation is vulnerable to outlier data, especially when there is a large range of values represented in the analysis. For this reason, an additional correlation analysis was conducted using the Spearman correlation coefficient. In this analysis, the rank order of each of two sets of measures is compared. This coefficient is better able to identify data sets that may be related, but the relationship may be more complex than linear. Another method to address data over a larger range is to make logarithmic transformations. For several of the data sets here, logarithmically transforming the data strengthened the correlations.

Figure 3 shows a scatterplot of GHG emissions versus toxicity-weighted emissions from facilities for which both types of data are available. The GHG emissions used are emitter-covered emissions for the year 2014, excluding emissions by facilities that were not covered by the program (e.g., biomass) and emissions related to electricity imports that were not local. This analysis only included facilities with emitter-covered emissions for which 2014 air toxics data were available ($n = 298$). Overall, this correlation was moderate, positive and highly significant by both measures (Pearson coefficient, $r = 0.32$; Spearman coefficient, $r = 0.44$; both statistically significant, $p<0.0001$).

When facilities were subdivided by Cap-and-Trade Program industrial sectors, some sectors showed considerably higher positive relationships. The scatterplots and correlations are presented in Figure 4 and Table 10 below, respectively. Refineries overall showed high positive correlations ($r \cong 0.8$), followed by oil and gas production facilities, hydrogen plants, and cement plants, each of which were moderately correlated using the Pearson coefficient ($r \cong 0.5$). For refineries, GHG emissions were highly correlated with toxicity-weighted air toxics emissions, as indicated by both the Pearson (0.82) and Spearman (0.86) correlation coefficient ($p\leq 0.0001$ for both coefficients). The Pearson correlations for hydrogen and cement plants were also supported by positive correlations using the Spearman coefficient. For the oil and gas production facilities, both measures showed positive correlation, but only the Pearson was statistically significant, suggesting that outliers or extreme values may have contributed to the Pearson correlation. It is also likely that the nature of the relationship between emissions of GHGs and air toxics varies substantially across these types of facilities. Also, how these facilities are defined differs across the different regulatory programs (see Appendix A for the definitions).[26] For electricity generation facilities, GHG emissions and toxicity-weighted emissions also showed low correlation; however, emissions levels across facilities varied broadly and logarithmic transformation resulted in a moderate (Pearson r = 0.41) and a highly significant correlation (p<0.001).

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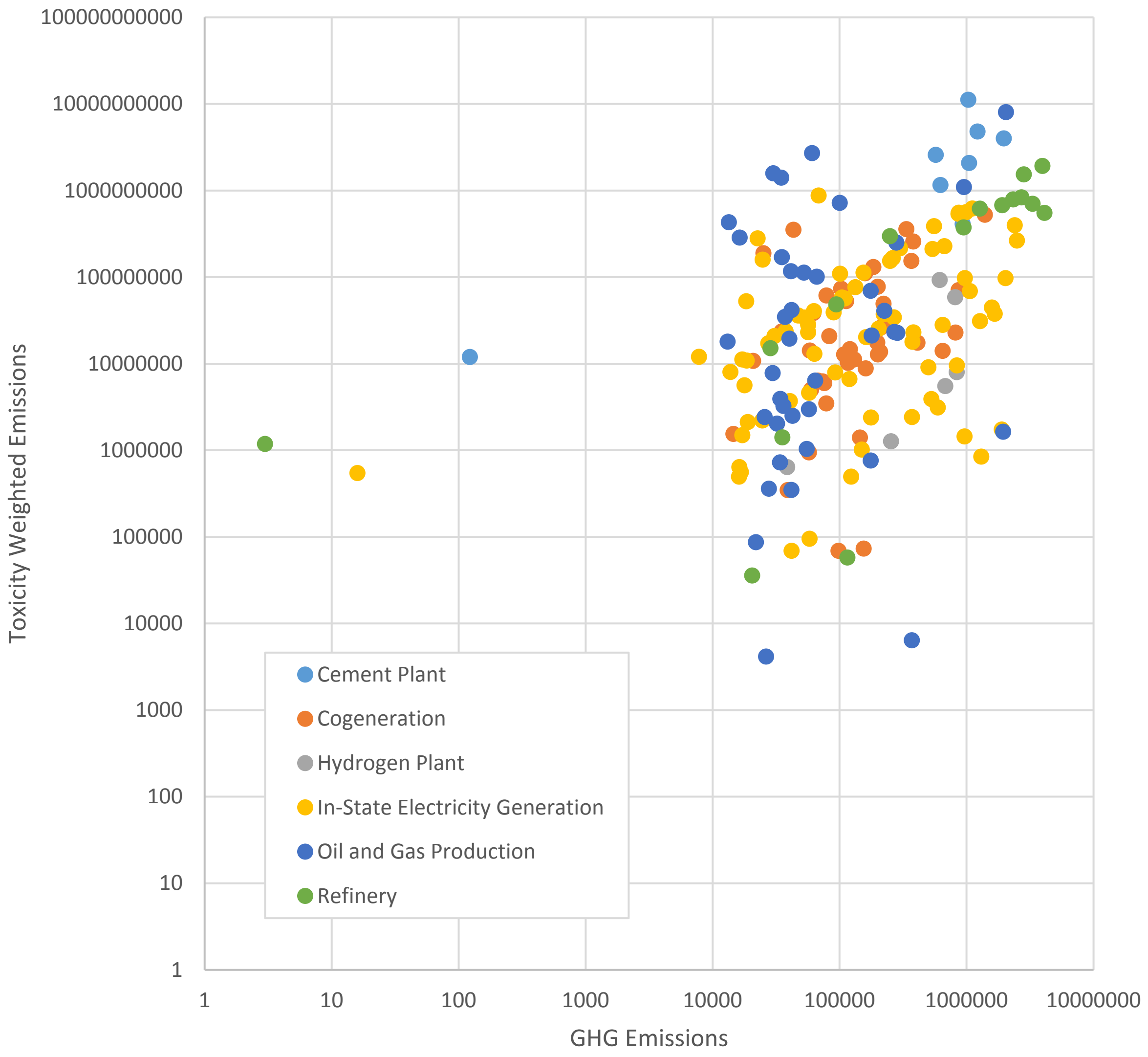
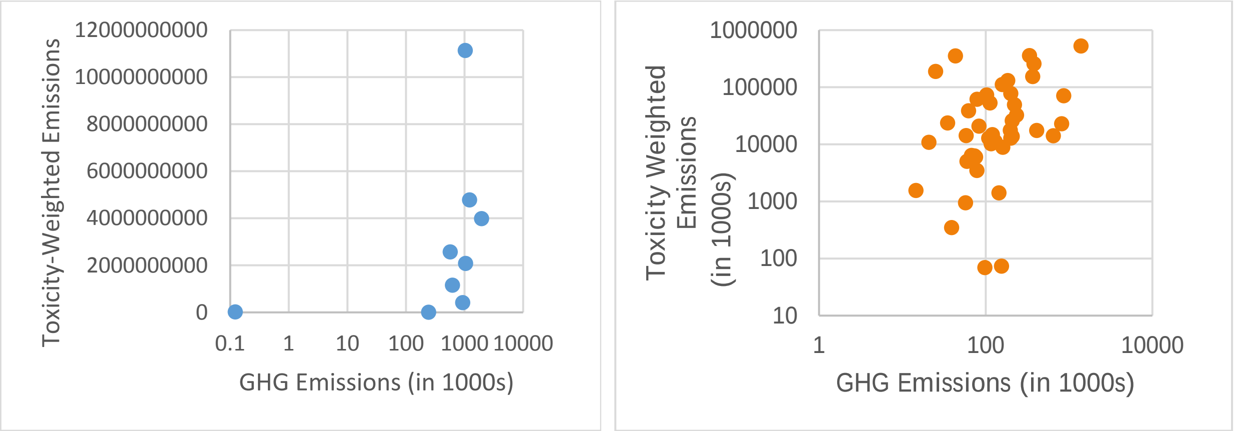
[26] ARB provides additional information on the differences between oil and gas facilities under different programs. See URL: https://www.arb.ca.gov/ei/tools/ievt/doc/ievt_oil_gas_crosswalk.pdf. The crosswalk table described in this document was not used for the initial analysis performed by OEHHA in this report.

Figure 3. Scatterplot of Toxicity-Weighted Emissions vs GHG Emissions from GHG Facilities with Emissions Data, by Cap-and-Trade Program Sectors (n=201)*

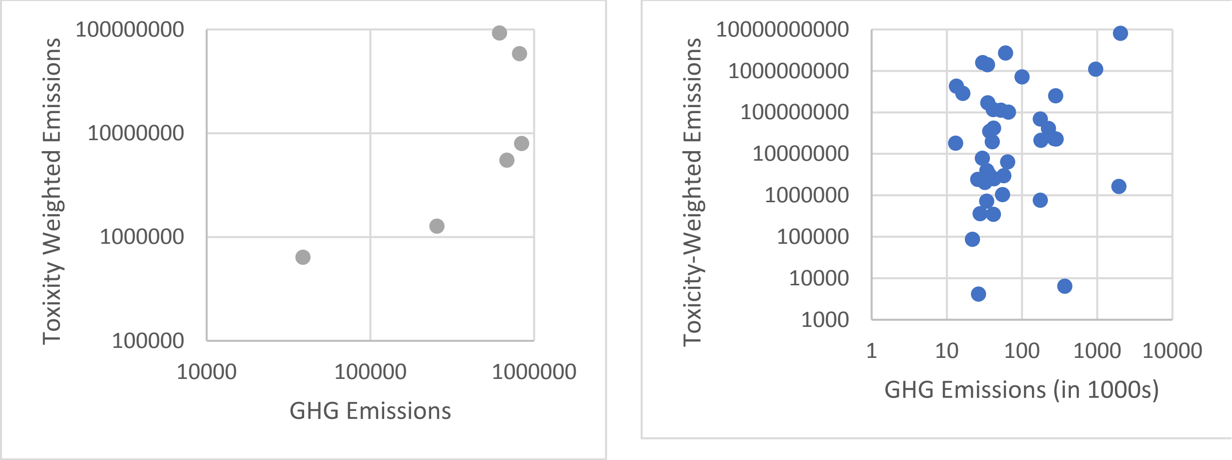


*The figure excludes "Other Combustion Sources" Category. GHG Emissions in MTCO$_2$e. Plotted on a Logarithmic Scale).

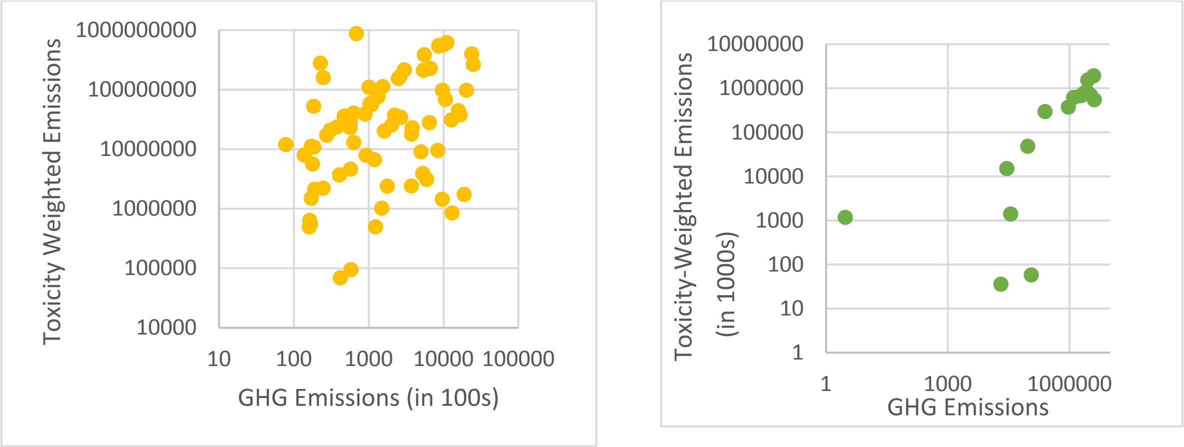
Figure 4. Scatterplots of Toxicity-Weighted Emissions vs GHG Emissions (MTCO$_2$e) by Cap-and-Trade Program Sectors (plotted on logarithmic scale).



Cement Plants (n = 9) **Cogeneration Facilities (n = 45)**



Hydrogen Plants (n = 7) **Oil and Gas Production Facilities (n = 41)**



Electricity Generation Facilities (n = 83) **Refineries (n = 16)**

Table 10. Correlation for GHG Emissions vs. Toxicity-Weighted Air Toxics Emissions for Cap-and-Trade Facility by Sector (2014 Emissions Data; Shaded r-Values Represent Statistically Significant Results, p<0.05).

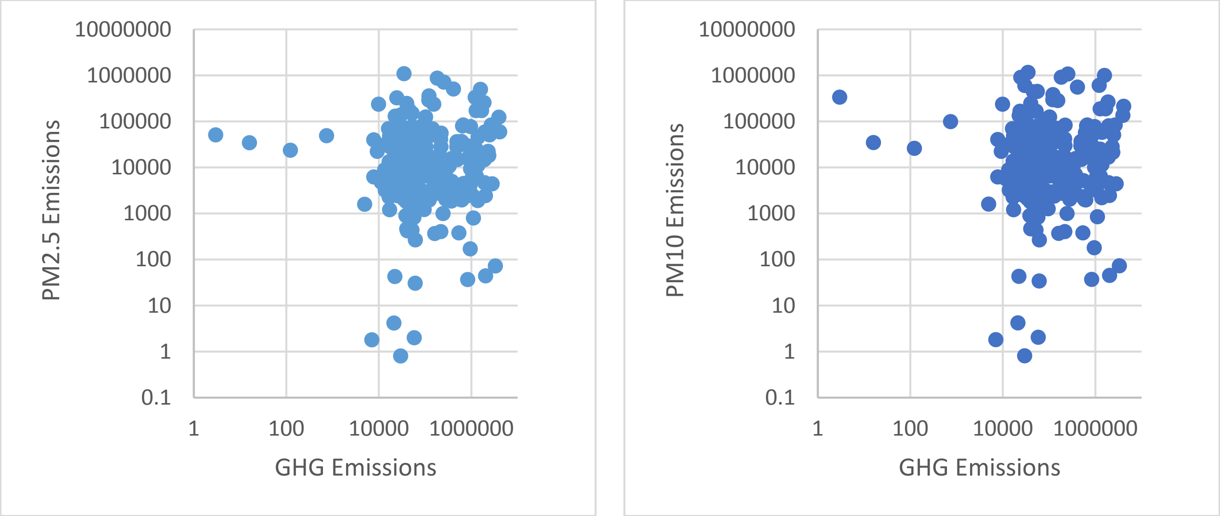
Sector	No.	Pearson (r-value)	Stat. Sig. (p-value)	Spearman (r-value)	Stat. Sig. (p-value)
Cement Plants	9	0.474	0.198	0.733	0.025
Cogeneration	45	-0.004	0.979	0.243	0.108
Hydrogen Plants	7	0.481	0.274	0.714	0.071
Oil & Gas Production	41	0.555	0.0002	0.100	0.533
Electricity Generation	83	0.173	0.119	0.282	0.0098
Refineries	16	0.818	0.0001	0.862	<0.0001

Criteria Air Pollutant and GHG Emissions

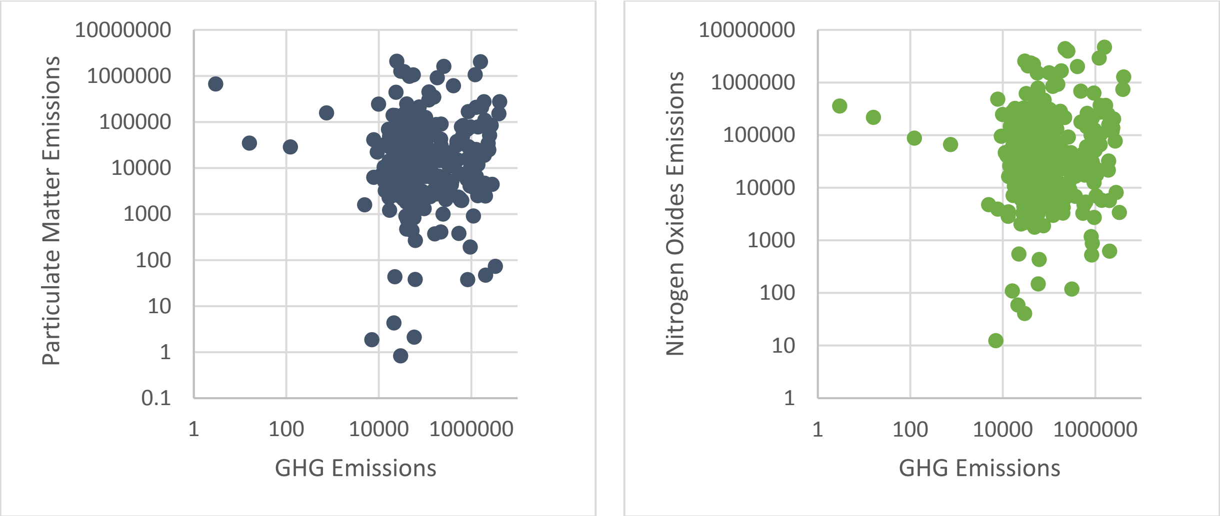
The relationships between GHG emissions and the emissions of specific criteria air pollutants from facilities were investigated in a manner similar to the analysis above using toxicity-weighted emissions. Figure 5 below show scatterplots of emissions of GHGs from facilities (as above) versus emissions of criteria air pollutants using data provided by ARB. Table 11 below shows the Pearson and Spearman correlation coefficients for each of the comparisons. This analysis includes facilities from all sectors for which data are available.

Because of the wide range of emissions of both GHGs and criteria air pollutants and the diverse nature of the industries analyzed here, the Spearman correlation likely provides more insight into probable relationships than the Pearson correlation. Here, Spearman correlations were moderately positive ($r \cong 0.5$) for total PM, PM10, PM2.5, SOx and NOx, individually. Correlations were poorer, though still positive, for organic and volatile gases (ozone-precursors), and carbon monoxide. Each of these correlations was statistically significant.

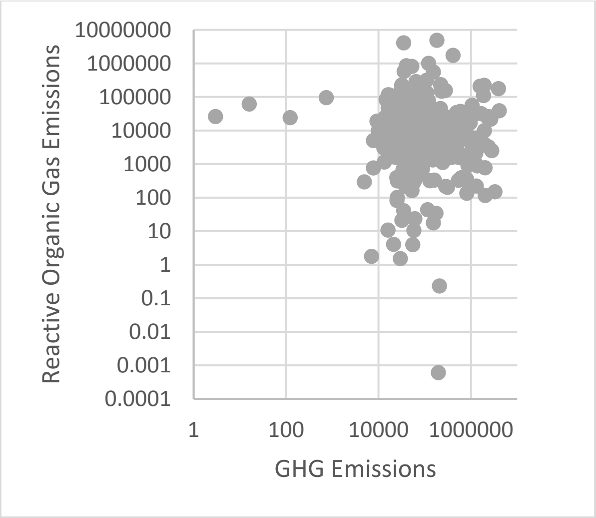
Figure 5. Scatterplots of Criteria Air Pollutant Emissions from All GHG Facilities with Emissions Data for the 2014 Reporting Year (n ≈ 316; Criteria Air Pollutant Emissions vs. GHG Emitter-Covered Emissions in $MTCO_2e$).



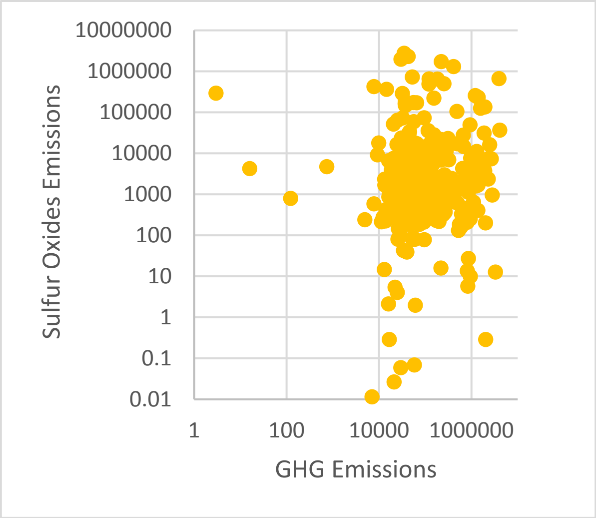
PM2.5 **PM10**



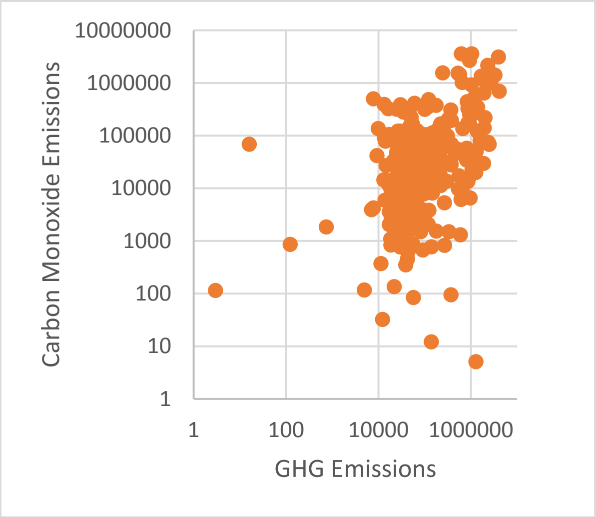
Total PM **Oxides of Nitrogen (NOx)**



Ozone-Generating Compounds (Reactive Organic Gases)



Oxides of Sulfur (SOx)



Carbon Monoxide

Table 11. Correlations between Emitter Covered GHG Emissions (in $MTCO_2e$) and Criteria Air Pollutant Emissions (in pounds) for All Cap-and-Trade Facilities with Emissions Data (2014 Data).

Pollutant	Correlation (r-value)*	
	Pearson	Spearman
CO	0.451	0.394
NOx	0.515	0.508
SOx	0.460	0.564
PM	0.467	0.455
PM10	0.617	0.499
PM2.5	0.718	0.554
ROG	0.642	0.246
TOG	0.693	0.389
VOCs	0.652	0.246

* All correlation r-values for both tests were statistically significant ($p<0.0001$).

OEHHA also examined relationships between individual criteria air pollutants and GHG emissions by industrial sector. These correlations are presented in a table in the Appendix (p. A-3). For refineries and in-state electricity generation facilities, correlations were moderate to high. All were statistically significant ($p<0.05$). Other sectors with high correlations include cement plants (NOx, PM, PM10, and VOCs) and hydrogen plants (TOG, VOCs).

Case Study: Cement Plants

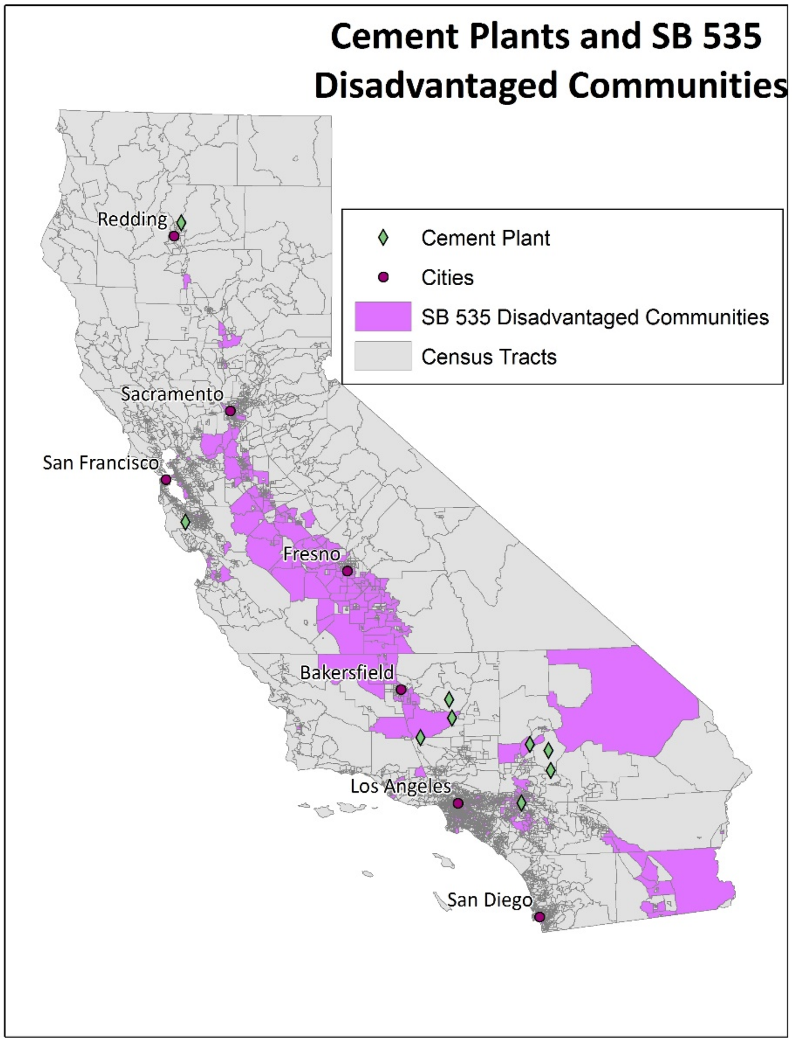
Cement manufacturing facilities were selected for a further analysis of the relationship between GHG emissions and emissions of toxic air contaminants. This sector was selected because (1) many of these facilities are among the highest scoring with respect to toxicity-weighted emissions to air (see Table 9) and (2) multi-year air toxics and criteria air pollutant emissions data are available from US EPA's Toxic Release Inventory (TRI) Program and ARB, respectively. While TRI data have not yet been broadly matched for each facility across all Cap-and-Trade facility sectors, TRI emissions data are available for the nine cement plants that are currently covered by the Cap-and-Trade Program. The nine facilities are listed in Table 12 below and shown on the map in Figure 6.

Table 12. California Cement Plants Evaluated for GHG and Air Toxics Emissions.

Facility Name	Approx. Location
*CalPortland Co Colton Plant**	Colton
CalPortland Co Mojave Plant	Mojave
Cemex Construction Materials Pacific LLC	Victorville
Lehigh Southwest Cement Co Cupertino	Cupertino
Lehigh Southwest Cement Co Redding	Redding
Lehigh Southwest Cement Co Tehachapi	Tehachapi
Mitsubishi Cement Corp	Lucerne Valley
National Cement Co Of California Inc	Lebec
Riverside Cement Oro Grande Plant	Oro Grande

*This facility ceased kilning operations in 2009; however, the plant retains grinding and distribution activities.

Figure 6. Location of Cement Plants Covered by the Cap-and-Trade Program.



The emissions data for these facilities were obtained for the years 2011-2014. GHG emissions were represented by those emissions that occurred locally and were covered by the Cap-and-Trade Program (emitter-covered emissions). TRI data obtained were toxicity-weighted emissions to air, as described above.[27] Since US EPA provides a calculated toxicity-weighted score for each facility, it was not necessary to adapt any of the chemical-specific scores, as was done for the data that originated from California's "Hot Spots" Program.[28] PM2.5 emissions data were obtained from ARB's CEIDARS (California Emission Inventory Development and Reporting System) data, which was downloaded from ARB's Integrated Emissions Visualization Tool.

Trends in emissions of both GHGs, air toxics, and PM2.5 are represented in Figure 7 below for each cement plant. One plant, CalPortland Colton, reported very low levels of GHGs and air toxics across all four years because it ceased kilning operations in 2009, though it continued to grind cement products. (This facility was excluded from the chart.) Across years within a given facility, there tended to be reasonable correlations in trends over time between GHG and toxicity-weighted emissions (for example, Cemex Construction Materials Pacific, Lehigh Southwest Cement Cupertino, Mitsubishi Cement, and Riverside Cement Oro Grande). Others showed poorer correlation (for example, CalPortland Mojave and National Cement). The pattern for National Cement is notable for a sudden increase in toxicity-weighted emissions in 2014. Further investigation of the specific chemical emissions data for this facility revealed that this increase was attributable to new reporting of chromium compound emissions in 2014, a departure from previous years. Since chromium emissions are generally consistently reported from cement plants, it is likely that the lack of chromium emissions for 2011-2013 is anomalous.

While year-over-year emissions at individual cement plants show some positive correlations, relative emissions of GHGs and toxicity-weighted air pollutants across facilities show fewer positive relationships. For example, Cemex Construction Materials Pacific had among the highest GHG emissions in this sector, while it was among the lower-scoring facilities for overall toxicity-weighted emissions, as reported to US EPA in their TRI program.

Although the observations from this specific industry are not directly applicable to other industries, this limited set of data suggests that year-over-year changes in GHGs within a facility are potentially meaningful in estimating changes in more toxic pollutants.

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[27] TRI data were obtained through the TRI.NET tool available at URL: https://www.epa.gov/toxics-release-inventory-tri-program/download-trinet.

[28] Toxicity-weighted emissions from TRI are not directly comparable to those calculated from California "Hot Spots" emissions data. These are different regulatory programs with different reporting requirements.

Figure 7. Cement Plants: Emitter Covered Emissions of GHGs (MTCO2e, MRR Data) (Top), Toxicity-Weight Air Emissions (TRI Data) (Middle) and PM2.5 Emissions (in tons, CEIDARS Data) (Bottom) over the Years 2011-2014.

Pearson and Spearman correlation coefficients were calculated using 2014 data on emissions of GHGs, air toxics, and PM2.5 and are shown in Table 13. The 2014 data used to calculate the correlations is shown graphically in Figure 7. GHG emissions and toxicity-weighted air emissions (TRI data) were not found to be correlated. A significant relationship (Spearman r ≅ 0.786, p-value = 0.0208) was observed between GHG emissions and PM2.5 emissions.

Table 13. Correlations for Emitter Covered Emissions of GHGs (MRR Data) vs. Toxicity-Weighted Air Emissions (TRI Data) or PM2.5 Emissions (CEIDARS Data) for Eight Cement Plants

GHG Emissions vs. --	No.	Pearson (r-value)	Stat. Sig. (p-value)	Spearman (r-value)	Stat. Sig. (p-value)
Toxicity-weighted air emissions	8	0.097	0.82	0.405	0.32
PM2.5	8	0.593	0.122	0.786	0.0208

*2014 Emissions Data; Shaded r-Values Represent Statistically Significant Results, p<0.05

Case Study: Refineries

Refineries represent another industrial sector covered by the Cap-and-Trade Program for which both GHG emissions and air toxics emissions data are available. Facilities from this sector were also identified as having among the highest toxicity-weighted emissions (see Table 9 above). Table 14 below lists 19 refineries reporting covered emissions in 2014. Most of these facilities are within one-half mile of an SB 535 disadvantaged census tract. Facilities have been grouped here by additional activities performed by the facilities that are relevant to GHG emissions, namely hydrogen production (generally for use by the refinery) and CO_2 production for off-site distribution.

Table 14. California Refineries Evaluated for GHG and Air Toxics Emissions. Shaded Rows Indicate Facilities within One-Half Mile of an SB 535 Disadvantaged Census Tract.

Facility Name	Approx. Location	Sectors*
Alon Bakersfield Refinery, Areas 1 & 2	Bakersfield	Refinery
Edgington Oil Company	Long Beach	Refinery
Kern Oil Refinery	Bakersfield	Refinery
Lunday-Thagard Company, DBA World Oil Refining	South Gate	Refinery
Paramount Petroleum Corporation Refinery	Paramount	Refinery
Phillips 66 Company, Santa Maria Refinery	Arroyo Grande	Refinery
Ultramar Inc, Valero Wilmington	Wilmington	Refinery
Phillips 66 Company, San Francisco Refinery	Rodeo	Refinery, H_2
San Joaquin Refining Company	Bakersfield	Refinery, H_2
Shell Oil Products US	Martinez	Refinery, H_2
Chevron Products Company	El Segundo	Refinery, H_2, CO_2
Chevron Products Company	Richmond	Refinery, H_2, CO_2
ExxonMobil Oil Corporation	Torrance	Refinery, H_2, CO_2
Phillips 66 Company, Los Angeles Refinery	Carson	Refinery, H_2, CO_2
Phillips 66 Company, Los Angeles Refinery	Wilmington	Refinery, H_2, CO_2
Tesoro Refining & Marketing Company LLC, Los Angeles Refinery	Carson	Refinery, H_2, CO_2
Tesoro Refining and Marketing Company	Martinez	Refinery, H_2, CO_2
Valero Refining Company, Refinery and Asphalt Plant	Benicia	Refinery, H_2, CO_2

* Refinery activities include production of hydrogen (H_2) on-site and production of CO_2 for distribution.

Figure 8. Location of Refineries Covered by the Cap-and-Trade Program.

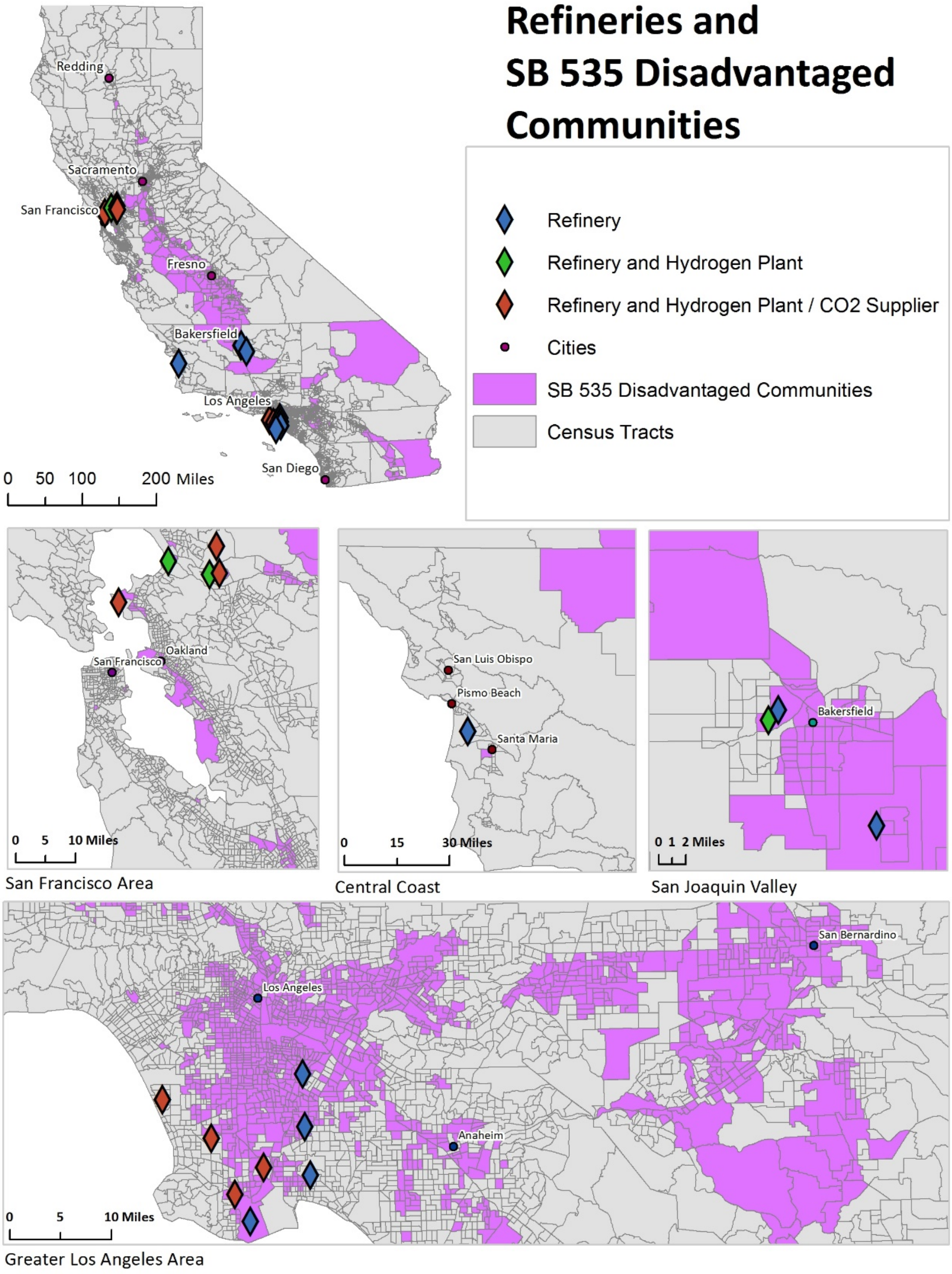
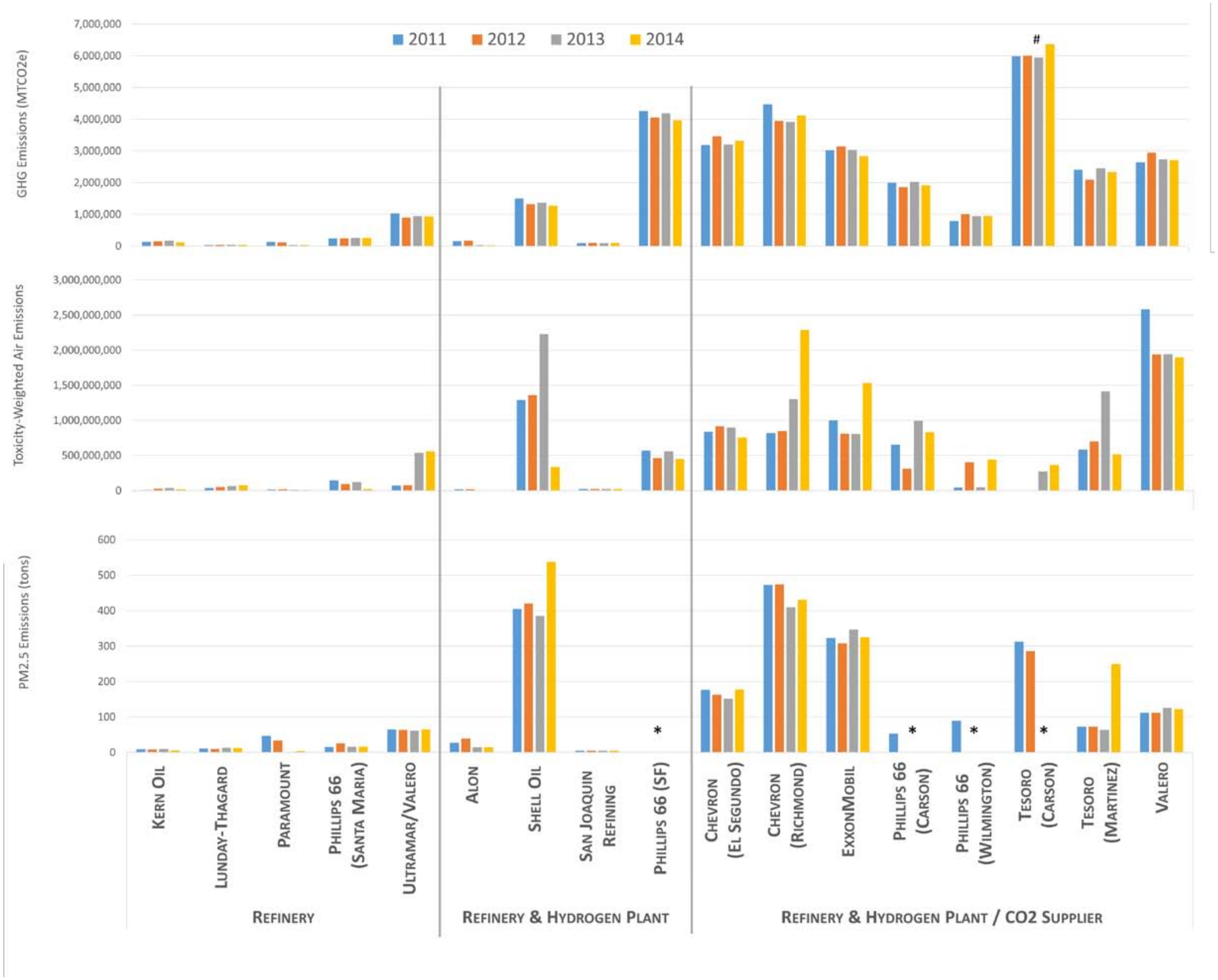


Figure 9. Refineries: Emitter Covered Emissions of GHGs (MRR Data) (Top), Toxicity-Weighted Air Emissions (TRI Data) (Middle), and PM2.5 Emissions (CEIDARS Data) (Bottom) for 18 Refineries Over the Years 2011-2014.



* Complete data (2011-2014) for PM2.5 emissions were not available for four facilities.

\# Emissions for three Tesoro refineries in Carson were combined in 2014 and are reported here as Tesoro (Carson). The emissions from the three facilities were added for the each of the 2011-2013 reporting years to produce the Tesoro (Carson) estimates.

Charts showing the trends in GHG, air toxics, and PM2.5 emissions over the years 2011-2014 are shown in Figure 8. Edgington Oil Company was omitted from the chart because emissions levels were negligible over this reporting period.

Correlations between covered GHG emissions and toxicity-weighted air emissions from refineries were positive and statistically significant using this US EPA data set for air toxics emissions (Pearson r-value = 0.56; p = 0.015; Spearman r-value 0.81, p<0.0001); the correlations increased with logarithmic transformation (Pearson r-value = 0.87, p<0.00001). Visual inspection of the overall patterns also suggests facilities with higher emissions of GHGs tend to have higher emissions of both toxicity-weighted emissions and PM2.5.

In certain cases, the emission levels across these types of facilities did not correlate well. For example, the Shell Oil refinery and hydrogen plant (Martinez) produced moderate GHG emissions, but it was one of the highest sources of PM2.5 emissions across all facilities. Similarly, the Valero refinery, hydrogen plant, and CO_2 distributor (Benicia) also produced modest levels of GHGs, but it had among the highest rates of toxicity-weighted air emissions. Differences in relative emissions may correspond, for example, to the types of products that are made at different facilities.

Table 15. Correlations for Emitter Covered Emissions of GHGs (MRR Data) vs. PM2.5 Emissions (CEIDARS Data) or Toxicity-Weighted Air Emissions (TRI Data) for Refineries*.

GHG Emissions vs. --	No.	Pearson (r-value)	Stat. Sig. (p-value)	Spearman (r-value)	Stat. Sig. (p-value)
Toxicity-weighted air emissions	18	0.563	0.0150	0.806	<0.0001
PM2.5	14	0.914	< 0.00001	0.916	< 0.00001

*2014 Emissions Data; Shaded r-Values Represent Statistically Significant Results, p<0.05

VIII Discussion & Conclusions

This initial analysis is intended to inform future investigation of potential benefits and impacts to disadvantaged communities from emissions of toxic air pollutants, especially to the extent they are influenced by the greenhouse gas limits put in place through activities pursuant to AB 32. However, there are not enough emissions data available at this time to allow for a comprehensive and conclusive analysis. This report makes some preliminary findings that OEHHA expects to build upon in future analyses as it acquires and evaluates more data, but does not provide definitive findings regarding the effects of the GHG limit on any individual community, or disadvantaged communities in general.

Still, at this point in time, the analysis shows that many SB 535 disadvantaged communities are likely to see benefits or impacts from changes in emissions from the facilities covered under the Cap-and-Trade Program. This is because a disproportionate number of these facilities are located in or very close to these communities, and 2014 data show that overall GHG emissions appear to be positively correlated with criteria air pollutants and toxic air contaminants, although within specific industrial sectors not all correlations are statistically significant. In addition, some of the most highly polluting of these facilities are more likely to be located in these communities.

The relationship between greenhouse gas and toxic air pollutant emissions is complex. Fuel combustion is a primary source of GHG emissions across many of the industrial sectors that are currently covered by the Cap-and-Trade Program. Fuel combustion is also likely to produce a number of toxic air pollutants. For this reason, responses by facilities to the Cap-and-Trade Program that result in reductions in fuel use or increases in fuel efficiency are likely to have benefits from reductions of toxic pollutants at similar levels of production. Toxic air pollutants from activities other than fuel combustion are likely to vary widely by industrial processes. Additional investigation is warranted to understand how industrial facilities will comply with the Cap-and-Trade Program’s requirements over time and how this may affect the release of air toxics.

For calendar year 2014 data, there are positive correlations between GHG, PM2.5 and toxic air pollutant emissions. The correlation between GHG and toxic emissions is especially notable in this initial analysis for refineries, hydrogen plants, and cement plants, although the total number of facilities in each of these sectors is relatively small. Further analysis by industrial sector and by specific chemical pollutants may reveal additional important relationships.

Future Data Collection and Analysis

The key challenge in analyzing the benefits and impacts of climate-change programs on disadvantaged communities is acquiring adequate data. As discussed in this report, data on emissions of GHGs, criteria air pollutants and toxic air pollutants are collected by multiple entities under different programs and statutory mandates. To date, there is no co-reporting of GHG and toxic emissions, and differences in reporting requirements across regulatory programs can complicate data analysis. In addition, toxic emissions data for many facilities are only updated every four years, further limiting conclusions that can be reached. Co-reporting of criteria, air-toxic and GHG emissions for the facilities subject to the Cap-and-Trade Program would aid investigation of emissions impacts. OEHHA will continue to acquire and analyze data for future reports, which will build upon the initial findings presented in this report.

Also, the Cap-and-Trade Program is still new, making it difficult to discern trends in how the program over time may be affecting emissions of criteria air pollutants and toxic air contaminants. As the program continues to generate data over the next several years, it will be easier to detect and evaluate any such trends. It will also be important to evaluate the Cap-and-Trade Program in concert with other climate policies to evaluate the entire climate change program in aggregate.

In the near-term, OEHHA intends to obtain pre-2014 toxic air pollutant data to investigate how such data can be used to analyze impacts in SB 535 disadvantaged communities. OEHHA will also explore how Cap-and-Trade Program data may be helpful to understanding the drivers of changes in toxic pollutant emissions.

OEHHA also intends to further examine relationships between the emissions of GHGs and toxic air pollutants in specific industrial sectors in order to gain a better understanding of likely benefits or impacts that may result from changes in GHG emissions, even if air toxics emissions data are not available.

Lastly, OEHHA will explore opportunities to examine potential benefits and impacts in disadvantaged communities for other AB 32 programs outside of the Cap-and-Trade Program. OEHHA will work with ARB in developing analyses to support implementation of the Cap-and-Trade Adaptive Management Program to identify and track any emissions increases that could be attributable to the Cap-and-Trade Program.

Appendix A

California’s Cap-and-Trade Program, Air Toxics “Hot Spots” Program, and US EPA’s Toxic Release Inventory Program each has slightly different definitions of “facility”. Some of these differences may have implications for how emissions data are reported such that there may not be an exact one-to-one relationship.

The following definitions of “facilities” are from different programs:

Cap-and-Trade Program

(144) (A) “Facility,” unless otherwise specified in relation to natural gas distribution facilities and onshore petroleum and natural gas production facilities as defined in section 95802(a), means any physical property, plant, building, structure, source, or stationary equipment located on one or more contiguous or adjacent properties in actual physical contact or separated solely by a public roadway or other public right-of-way and under common ownership or common control, that emits or may emit any greenhouse gas. Operators of military installations may classify such installations as more than a single facility based on distinct and independent functional groupings within contiguous military properties.

(B) “Facility,” with respect to natural gas distribution for the purposes of sections 95150 through 95158 of MRR, means the collection of all distribution pipelines and metering-regulating stations that are operated by a Local Distribution Company (LDC) within the State of California that is regulated as a separate operating company by a public utility commission or that are operated as an independent municipally-owned distribution system.

(C) “Facility,” with respect to onshore petroleum and natural gas production for the purposes of sections 95150 through 95158 of MRR, means all petroleum and natural gas equipment on a well-pad, or associated with a well pad or to which emulsion is transferred and CO_2 EOR operations that are under common ownership or common control including leased, rented, or contracted activities by an onshore petroleum and natural gas production owner or operator and that are located in a single hydrocarbon basin as defined in section 95102(a) of MRR.

When a commonly owned cogeneration plant is within the basin, the cogeneration plant is only considered part of the onshore petroleum and natural gas production facility if the onshore petroleum and natural gas production facility operator or owner has a greater than fifty percent ownership share in the cogeneration plant. Where a person or entity owns or operates more than one well in a basin, then all onshore petroleum and natural gas production equipment associated with all wells that the person or entity owns or operates in the basin would be considered one facility.

Air Toxics ‘Hot Spots’ Program

Health and Safety Code, Section 44304 defines facility as “every structure, appurtenance, installation, and improvement on land which is associated with a source of air releases or potential air releases of a hazardous material.” The Guidelines further state that: “[e]xcept for the oil production operations defined in section X.14(b), for purposes of this regulation, the phrase "every structure, appurtenance, installation" shall mean all equipment, buildings, and other stationary items, or aggregations thereof, (A) which are associated with a source of air emission or potential air emission of a listed substance; (B) which involve activities that belong to the same two-digit Standard Industrial Classification code, or are part of a common operation; (C) which are located on a single site or on contiguous or adjacent sites; and (D) which are under common ownership, operation, or control, or which are owned or operated by entities which are under common ownership, operation, or control."

US EPA Toxic Release Inventory Program

Facility definition: "An entire facility means all buildings, equipment, structures, and other stationary items which are located on a single site or on contiguous or adjacent sites and which are owned or operated by the same person (or by any person which controls, is controlled by, or under common control with such person). A facility may contain more than one establishment."

Table A1. Pearson (P) & Spearman (S) Correlation Coefficient R-Values for Criteria Air Pollutants and GHGs by Industrial Sector. Shaded Boxes Indicate Statistically Significant Correlations.

	Cement Plants		Cogeneration		Hydrogen Plants		Electricity Generation		Oil & Gas Production		Refineries		Other Combustion	
	P	S	P	S	P	S	P	S	P	S	P	S	P	S
CO	0.094	0.050	-0.031	0.197	-0.072	0.464	0.262	0.465	0.519	0.073	0.802	0.918	0.318	0.186
NOx	0.877	0.883	0.128	0.363	0.612	0.786	0.472	0.728	-0.026	0.122	0.913	0.921	0.884	0.306
SOx	0.193	0.467	0.211	0.484	0.574	0.771	0.487	0.651	0.265	0.361	0.675	0.797	0.202	0.544
PM	0.785	0.867	0.025	0.220	0.538	0.500	0.699	0.648	0.259	0.184	0.883	0.906	0.414	0.442
PM10	0.748	0.833	0.095	0.294	0.574	0.679	0.711	0.655	0.260	0.190	0.898	0.944	0.509	0.499
PM2.5	0.645	0.817	0.137	0.377	0.608	0.786	0.713	0.663	0.261	0.189	0.908	0.944	0.616	0.598
ROG	0.604	0.467	0.267	0.108	0.547	0.643	0.441	0.439	0.155	0.207	0.833	0.965	-0.003	0.043
TOG	0.525	0.467	0.331	0.148	0.799	0.821	0.556	0.660	0.255	0.271	0.892	0.959	0.075	0.141
VOCs	0.698	0.667	0.267	0.152	0.765	0.714	0.505	0.480	0.155	0.207	0.845	0.956	0.006	0.044

Environmental Science & Technology

Model to Investigate Energy and Greenhouse Gas Emissions Implications of Refining Petroleum: Impacts of Crude Quality and Refinery Configuration

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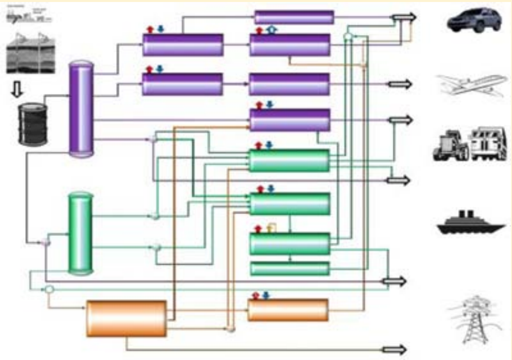
Ⓢ *Supporting Information*



ABSTRACT: A petroleum refinery model, Petroleum Refinery Life-cycle Inventory Model (PRELIM), which quantifies energy use and greenhouse gas (GHG) emissions with the detail and transparency sufficient to inform policy analysis is developed. PRELIM improves on prior models by representing a more comprehensive range of crude oil quality and refinery configuration, using publicly available information, and supported by refinery operating data and experts' input. The potential use of PRELIM is demonstrated through a scenario analysis to explore the implications of processing crudes of different qualities, with a focus on oil sands products, in different refinery configurations. The variability in GHG emissions estimates resulting from all cases considered in the model application shows differences of up to 14 g CO_2eq/MJ of crude, or up to 11 g CO_2eq/MJ of gasoline and 19 g CO_2eq/MJ of diesel (the margin of deviation in the emissions estimates is roughly 10%). This variability is comparable to the magnitude of upstream emissions and therefore has implications for both policy and mitigation of GHG emissions.

■ INTRODUCTION

The petroleum refining industry is the second-largest stationary emitter of greenhouse gases (GHG) in the U.S.[1] (third-largest in the world[2]). Annual GHG emissions from a large refinery are comparable to the emissions of a typical (i.e., 500 MW) coal-fired power plant.[3,4] For U.S. refineries, where most of the North American production of petroleum-derived fuels occurs, annual emissions were reported to be close to 180 million tonnes of CO_2eq in 2010, representing nearly 12% of U.S. industrial sector emissions or 3% of the total U.S. GHG emissions.[1,5−7]

This industry faces difficult investment decisions due to the shift toward "heavier" crude in the market, both domestic and imported. For example, in 1990, the fraction of imported crude into the U.S. classified as heavy (at or below API gravity, a measure of density, of 20) was roughly 4%. By 2010 this fraction had increased to 15%.[8] Between 2008 and 2015, it is estimated that more than $15 billion will be spent to add processing capacity specifically for heavy crude blends in U.S. refineries.[9] Each refinery must decide whether and how much they will process heavy crude while considering that processing such crudes requires more energy and results in higher refinery GHG emissions. These major capital investment decisions will impact the carbon footprint of the refining industry for decades to come.

Current and future environmental regulations will also affect the decisions faced by this industry. Life cycle assessment (LCA) has been expanded as a tool to enforce GHG emissions policies. For example, California's Low Carbon Fuel Standard[10] (CA-LCFS) embeds life cycle assessment within the policy to measure emissions intensity of various transportation fuel pathways through their full life cycle (including extraction, recovery, and transport). Using LCA in this way requires more accurate assessments of the emissions intensity upstream of the refinery for each crude. However, the varying quality of these crudes will also have significant implications for refinery GHG emissions. Therefore, in this paper we argue that more accurate assessments of the impact of crude qualities on refinery emissions are also required to appropriately account for the variations in emissions and avoid potential unintended consequences from such policies.

The implications for refinery GHG emissions of processing oil sands (OS) products provide a good case study due to the link between upstream processing decisions and refinery emissions, as well as the wide variety of OS products. Canada has the world's third largest petroleum reserves and is the top supplier of imported oil to the U.S.[11] The OS resource represents over 97% of Canada's oil reserves.[12] Current OS operations produce bitumen (an ultraheavy petroleum product) that undergoes either dilution (to produce diluted bitumen referred to as dilbit, synbit, or syndilbit) or upgrading processes

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Table 1. Canadian Crudes under Analysis[a]

	Crude Categories	*Production Volumes*	*Configuration selected in Base Case*	*Description*	*S wt%*	*API*	*H wt%*	*MCR wt%*	*~Kw*	*Tb$_{50}$ (°C)*
Bitumen 1	**Bitumen** No bitumen currently goes to refinery. Bitumen case may apply if diluent (condensate) is not used at the refinery.	1.4 M bpd in 2009 including bitumen processed at upgraders[b]	Deep Conversion: Coking and fluid catalytic cracking	Confidential	5.0	8.2	10.1	14.7	11.6	427
Bitumen 2				Confidential	4.1	12.1	10.3	10.9	11.0	442
Dilbit 2	**Diluted bitumen**: (Dilbits) using condensate at a 25:75 % diluents-to-bitumen ratio. Synthetic bitumen blend (Synbit) 50:50 % Light SCO -to-crude ratio. Syndilbit is a bitumen blend with Light SCO and condensate.	Synbit and Syndilbit comprise nearly 2% OS production[b]	Deep Conversion: Coking and fluid catalytic cracking	**Cold Lake (CL):** Asphaltic heavy crude blend of bitumen (11API/5.5%S) and condensate (65API/0.1%S). CL Production ranges from 150 kbd to 200kbd of blend	3.9	20.7	11.2	10.6	11.8	458
Syn-dilbit 1		All diluted bitumens comprise nearly 49% OS production[b]		**Albian Heavy Synthetic** (AHS) contains vacuum residuum (which is an exception for SCOs). It is a blend of sweet SCO crude with unconverted oil from resid hydrocracking	2.2	19.5	10.7	10.9	11.6	447
SCO, So,H1	**Synthetic Crude Oil (SCO)** is a blend of naphtha, distillate, and gas oil range crude fractions. Sweet (Sw) blends comprise majority of SCO production. It has been estimated that 75% of the 2007 SCO production was light Sw SCO without vacuum resid[56]	Nearly 13% OS production[b]	Deep Conversion: Coking and fluid catalytic cracking	**Suncor Synthetic H (OSH)** is a sour synthetic blend. It is comprised of roughly 75% virgin gas oil and 25% lighter fractions.	3.1	19.9	11.1	0.6	11.4	393
SCO, Sw, M1		Nearly 38% OS production[b]	Medium Conversion: fluid catalytic cracking	**Syncrude Synthetic** (SYN) sweet SCO derived from combination of hydroprocessing and fluid coking technologies at upstream upgrading operations. SYN production 58.9 kbd	0.1	31.5	12.5	0.1	11.8	321
SCO, Sw, L1			Hydroskimming	**Husky Synthetic Blend** (HSB) sweet SCO derived from combination of hydroprocessing and delayed coking technologies at upstream upgrading operations. Upgrading production is around 53 kbd	0.1	32.6	12.9	0.1	11.9	329
SCO, Sw, L2				**Suncor Synthetic A (OSA)** sweet SCO. Suncor Upgrading production is around 280 kbd; 60% production is light Sw SCO. i.e., OSA production close to 168kbd	0.2	33.1	12.7	0.02	11.9	315
Conv, So,H1	**Canadian Conventional crude (Conv)**, as oil sands products, are classified based on API (Light API>32, Medium 32>API>22, Heavy API <22) and sulfur content (Sweet S< 0.5wt%, Sour S> 0.5wt%)	6% U.S. Crude oil imports[c]	Deep Conversion: Coking and fluid catalytic cracking	**Bow River North.** Conventional benchmark.	2.7	21.1	11.64	8.57	11.7	427
Conv, So, M1			Medium Conversion: Fluid catalytic cracking	**Midale** (Benchmark medium sour crude)	2.3	29.6	12.1	5.8	11.9	361
Conv, So, L2				**Sour High Edmonton**	1.4	34.9	12.8	3.8	12.8	323
Conv, Sw, L2			Hydroskimming	**Mixed Sweet Blend**	0.4	39.2	13.2	2.0	12.2	298

[a] S: Sulfur content; API: gravity; H: hydrogen content; MCR: micro carbon residuum; ~Kw: approximated Watson characterization factor using Tb$_{50}$ in wt.; Tb$_{50}$: temperature at which 50% of the mass is recovered through distillation of the whole crude; wt: weight basis; So: sour; Sw: sweet; H: heavy; L: light; kbpd: thousand barrels per day. [b] Calculation basis (2009): 1361 kbpd of oil sands products derived from 1269 kbd of raw bitumen,[57] and 75% of the SCO production ends in sweet light products. [c] Calculation basis (2009): 1269 kbpd U.S crude oil imports from Canada (i.e., 21% of U.S. crude oil imports).[8] 898 kbpd oil sands products exported to U.S. (i.e., 67% of oil sands products[57]); thus, 371 kbpd conventional crude oils exported to U.S. (i.e., 4% of U.S. crude oil imports).

(to produce a high quality synthetic crude oil, SCO) prior to sale to petroleum refineries. Therefore, a diversity of product quality is possible from these operations. Table 1 lists and describes the main characteristics of each category of OS products. The impacts of different OS processing decisions on refinery GHG emissions have the potential to be large and have yet to be explored in depth.

A petroleum refinery is a set of interconnected but distinct process units that convert relatively low value liquid hydrocarbon material (resulting from blending multiple streams of crude feedstock) into more valuable products by increasing its hydrogen to carbon ratio. Different combinations of process units (configurations) are possible leading to a wide variety of potential refinery configurations. In a refinery, a distillation process separates the "whole crude" into groups or "fractions". These fractions are made up of molecules with a particular boiling point temperature range. These ranges are defined by "cut temperatures". Each fraction is then sent to different process units where chemical and thermal processes fragment and/or rearrange the carbon and hydrogen bonds of the hydrocarbon while eliminating the undesired components such as sulfur and nitrogen that are also present in each fraction. Each refinery has a final product specification which dictates the volume and quality of each desired end product (e.g., *X* barrels of gasoline with Y% sulfur). A combination of input crudes is selected and process units are operated to satisfy such specifications.

Crude quality and refinery configuration affect GHG emissions related to processing a particular crude. Crude quality is defined by physical and chemical properties (e.g., the hydrogen content of the crude fractions) that determine the amount and type of processing needed to transform the crude into final products. The technologies employed, as well as how they are combined in operation in a refinery, will require different types and amounts of energy inputs and will produce different types and amounts of energy byproducts (e.g., coke) and final products (e.g., gasoline). For example, heavier crudes generally require more energy to process into final products than lighter crudes due to their need for additional conversion processes and their low hydrogen content.

Two prominent North American life cycle (LC) tools are now forming the basis of regulation as opposed to their original objective of informing policy: Natural Resource Canada's GHGenius[13] and Argonne National Laboratory's Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation (GREET).[14] The GREET model and the CA-GREET version, used as the basis of CA-LCFS, do not account for the effects of crude quality at the refinery stage in their calculations (i.e., all crudes will have the same energy requirements and GHG emissions). GHGenius accounts for crude quality by modifying a default energy intensity value using the average API gravity and sulfur content of an entire refinery crude slate (i.e., a combination of crudes blended as they enter the refinery) and a regression model based on historic regional refinery performance data. [15] The LC models' approaches do not decouple the effects of changes in energy requirements due to changes in crude quality and the changes in each refinery's performance (e.g., process unit efficiencies), nor do they develop a consensus on the impact of allocation (how environmental impacts are split across products in a multiproduct industry).[16] It is possible to combine the use of LC-based models and refinery simulators to calculate LC energy use and GHG emissions for a particular crude and refinery;[17] however, this is not a straightforward effort as will be demonstrated by this paper.

Peer-reviewed analysis that investigates energy and GHG implications of shifting to heavier crudes in refineries has only recently started to appear (since 2010).[18,19] However, these studies did not explore differences in emissions intensity of selected technologies nor investigate the full range of different qualities of crudes derived from the OS operations. Three nonpeer reviewed studies, conducted using a LC framework, have investigated OS crude quality effects on refinery GHG emissions.[17,20−22] However, these studies have used proprietary refinery models limited in the transparency needed to understand the boundaries, assumptions, and data used as well as the ability to evaluate alternate scenarios or pathways.[23] The literature does not present a transparent tool nor recommend a method that predicts GHG emissions with the ability to capture the impact of crude quality and refinery configuration (see Supporting Information (SI) for detailed review of the literature).

This paper (1) provides an overview of the development of the Petroleum Refinery Life-cycle Inventory Model, PRELIM, including model structure and crude assay inventory as well as calculations and assumptions; (2) applies the model to assess the impact of crude quality and refinery configuration on energy use and GHG emissions including a comprehensive set of OS products and conventional crudes; (3) explores the most influential parameters in the model for determining energy use and GHG emissions through scenario analysis; and (4) compares results from previous studies with those from the application of PRELIM.

■ METHOD

PRELIM is a stand-alone, spreadsheet-based model built using a LC approach by employing refinery linear programming modeling methods to represent a range of possible configurations reflecting currently operating refineries in North America. The LC/systems-level approach provides the structure to obtain a tool of wide applicability (i.e., not specific to any one refinery but capable of representing a wide variety of refinery configurations) in the assessment of refinery LC energy use and GHG emissions for crudes of different quality, and allows for the easy incorporation of model results into Well-To-Wheel analyses (WTW). WTWs are a variant of LCAs focused on transportation fuels. The refinery linear programming modeling methods[24] allow for process unit and overall refinery mass balances. These methods overcome the lack of crude specificity of previous LC models[16,25,26] and facilitate exploration of alternative LC inventory allocation methods at the refinery subprocess (i.e., process unit) level. Because the model structure allows for the investigation of two key LCA concepts (i.e., functional unit and allocation[27−29]) as recommended by the International Standard ISO 14041,[30] the model has been called the Petroleum Refinery Life-cycle Inventory Model.

Model Structure and Key Assumptions. Scheme S.1 in the SI presents a basic flow diagram of the overall refinery model structure and how the process units are connected. PRELIM can simulate up to ten specific refinery process configurations. All refinery configurations include crude distillation, hydrotreating, and naphtha catalytic reforming processes. The configurations are differentiated by whether or not the following conversion technologies are present: gas oil hydrocracking, fluid catalytic cracking (referred to hereafter as FCC), delayed coking, and residual hydrocracking. Supporting unit processes such as steam methane reforming (SMR) and acid gas treatment are also included.

Each configuration requires a different amount of energy to process a crude and produces a different slate (i.e., volume and type) of refinery final products including transportation fuels (i.e., gasoline, kerosene, and diesel) as well as heavy fuel oil, hydrogen from the naphtha catalytic reforming process, refinery fuel gas (i.e., gas produced as a byproduct in process units within the refinery), and the possible production of coke or hydrocracking residue. To run the model, a user must select the crude, the configuration, and the allocation method desired through the spreadsheet-based interface. Default values can be used to represent the crude properties and energy requirements of each process unit. Crude properties can be represented by selecting a crude from the crude assay inventory in the model. Alternatively, a user can input a new crude assay and/or can modify any of the process unit model parameters either by selecting a value from the range of parameter values available in the model or by inputting their own parameter value(s). To characterize the whole crude and its fractions, a total of 62 parameters are input to the model, accounting for five crude oil properties: crude distillation curve (i.e., information about mass and volume yields of each fraction, and individual fraction characteristic boiling point), API gravity, sulfur content, hydrogen content, and carbon residue. Supporting information describes how these crude properties affect the refinery energy use and GHG emissions estimates. Two additional crude properties, aromatic content and crude light ends content, impact refinery GHG emissions estimates and are modeled indirectly in PRELIM. PRELIM uses information about the quantity and type of energy required by an individual refinery process unit and assumes that the process energy requirements (electricity, heat, and steam) are linearly related to the process unit's volumetric feed flow rate.[31] This assumption is key to differentiate the energy required to refine crudes with different distillation curves (and therefore different volumes of each fraction that will pass through each process unit). Justification is provided in the SI.

PRELIM calculations include the upstream energy use and GHG emissions associated with the energy sources (i.e., electricity and natural gas).[32] Fugitive GHG emissions from a refinery tend to be an order of magnitude lower than combustion emissions[33] and are not considered in the current version of PRELIM.

The data available in the model for process unit energy requirements are presented as a default as well as a range of plausible values for each parameter derived from the literature.[24,34−37] The data were compared with confidential information and evaluated in consultation with experts from industry to verify that the values and their ranges are appropriate. PRELIM default values for process unit energy requirements are mostly from Gary et al.[35,38]

PRELIM can calculate overall refinery energy use and GHG emissions on a per barrel of crude or per megajoule (MJ) of crude basis, as well as energy use and GHG emissions attributed to a particular final product on a per MJ of product basis (e.g., per MJ of gasoline). For the latter type of functional unit, refinery energy use is allocated to final products at the refinery process unit level (SI details PRELIM allocation procedures, available options in the model, and the implications of different allocation methods). Summing the energy use across all refinery final products on a mass flow rate basis, and comparing to the total energy requirements summed across all process units, verifies the energy balance in the system (all results are reported on a lower heating value basis).

Differences in hydrogen content among crude feedstock and refinery final products are important factors that drive refinery CO_2 emissions.[19] In PRELIM, a global hydrogen mass balance method[39] is used to determine hydrogen requirements for each hydroprocessing unit (hydrotreating and hydrocracking) as well as byproduct hydrogen production from the naphtha catalytic reforming process unit. The method accounts for differences in the hydrogen content of different crudes and the assumption that all crudes are to be processed to meet intermediate and final product hydrogen specifications. Accurately estimating hydrogen requirements is one of the most critical model components (see SI for a more detailed discussion).

PRELIM uses correlations to determine yields of intermediate and final refinery products for each process unit. All correlations used in PRELIM are based on Gary et al.[35] The SI details assumptions about product yields for each process unit.

PRELIM Crude Assay Inventory. The PRELIM crude assay inventory is developed to allow a user the option to select from a predetermined list of crude assays. The current inventory includes publicly available data representing 22 Western Canadian crudes tracked by the Canadian Crude Quality Monitoring Program (CCQMP).[40] Also, the inventory includes seven additional assays from confidential sources to characterize a comprehensive range of qualities for OS-derived products (i.e., bitumen, diluted bitumen, SCO). Currently, there are at least two crude assays representing each category of crude (e.g., bitumen, diluted bitumen, and SCO are all categories of crudes). Western Canadian Conventional crudes are well-characterized using the data available in the public realm. Due to data availability we do not include a full suite of conventional crudes in our analysis. However, preliminary analysis of international crudes shows that the range of emissions presented for Canadian conventional crudes provides a rough approximation of the range of refinery emissions for light crudes globally. However, further analysis is required to confirm this and provide a complete LC comparison.

PRELIM requires characterization of the properties for nine crude fractions (see Scheme S.1). The method of separating the crude into nine fractions is selected to allow the flexibility needed to model different refinery configurations. CCQMP assays must be transformed to obtain the complete set of information needed. The SI details the transformation methods and the results of an evaluation of the methods used. In PRELIM, each particular crude assay is run individually, as opposed to running a crude slate. A crude-by-crude analysis was also suggested and tested in ref 22, and the impact of this simplification on emissions estimates is expected to be small.

Model Evaluation. PRELIM reduces the level of complexity in modeling refinery operations compared to the models used by the industry to optimize their operations. Confidential data (associated with crude assays, operating conditions, and energy requirement estimates) and consultation with refining experts were necessary to assess the validity of PRELIM input data and assumptions. In addition, sensitivity analyses and/or alternative logic calculations to estimate particular parameters were conducted. Finally, a covalidation exercise was conducted by comparing PRELIM's outputs with those of a more detailed refinery model to assess PRELIM's performance, identify any improvements required, and specify the level of accuracy that can be expected when using the model to inform policy.

The covalidation shows that the PRELIM model is capable of replicating the estimates of CO_2 emissions from a more complex model with a reasonable range of error/variability. Overall, the margin of deviation in the emissions estimates due to both assay data quality and the modeling approach is below 10% in almost all cases, which is within the error bounds of typical LC inventories.[41−43] Deviations in energy requirements, which lead to emissions deviations, are mainly associated with estimates for the hydrogen required which is also an uncertain variable in actual refinery operations.[39,44] The deviations are also explained in part by flexibility exhibited by real refinery operating conditions as well as assumptions in modeling. The SI details methods and results of this exercise.

Model Application. A scenario analysis[45] is used to explore the effects that crude quality and refinery configuration have on refinery energy use and GHG emissions estimates.

The starting point for the analysis is a "Base Case Scenario" (referred to hereafter as base case): a set of conditions (e.g., different crudes, emission factors, process unit energy intensities, allocation assumptions) to determine the refinery energy use and GHG emissions of a crude in a "default" refinery configuration. The purpose of the base case is to explore plausible scenarios in which only energy use and GHG emissions associated with the minimum processing capacity needed to transform each crude into transportation fuels or

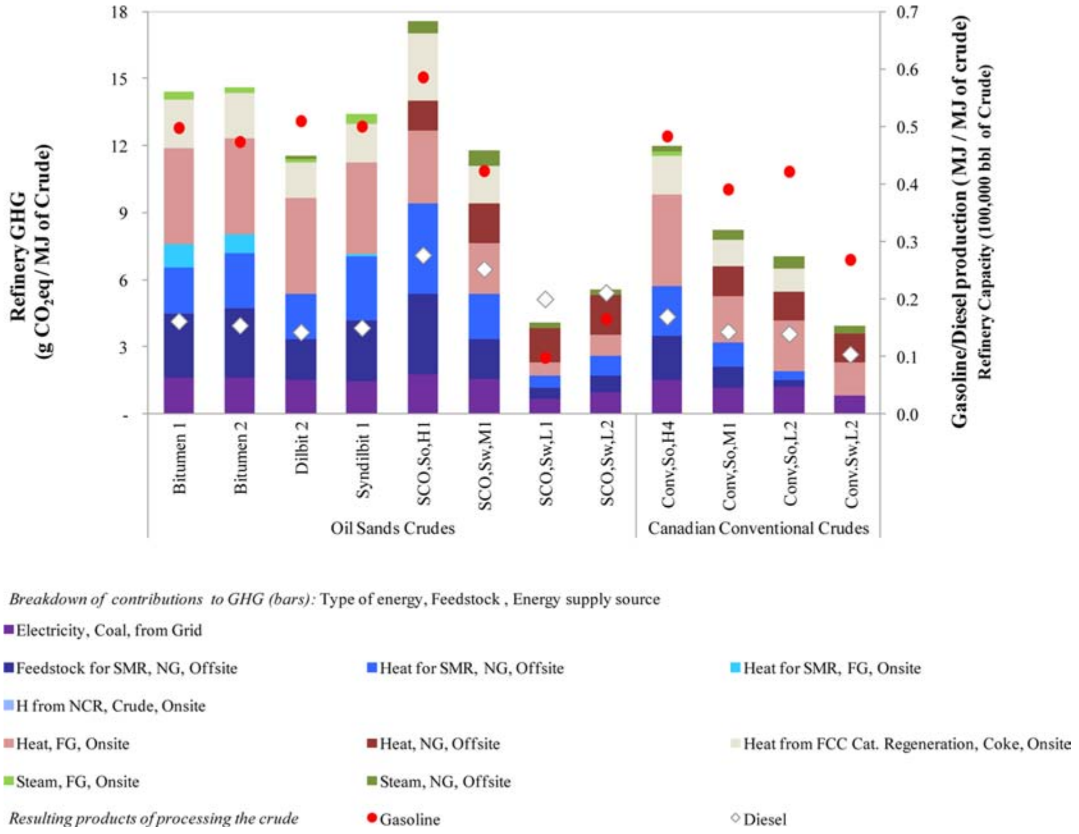

Figure 1. Base case greenhouse gas (GHG) emissions estimates and gasoline and diesel production from refining 100 000 bbl of different crudes. Major assumptions about base case: (1) Refining configuration is based on API and sulfur properties of the whole crude for both crude categories Conventional and OS-derived crudes: API (light API > 32, medium 32 > API > 22, heavy API <22) and sulfur content (S) (sweet S < 0.5 wt %, sour S > 0.5 wt %). Sweet light crudes (Sw, L) are run in a hydroskimming refinery; sour light (So, L), sweet medium (Sw, M), and sour medium (So, M) crudes are run in a medium conversion refinery; and heavy crudes (H: conventional, bitumen, dilbits) are run in a full conversion refinery. (2) Upgrading process units for the medium conversion refinery include a fluid catalytic cracking (FCC) process unit, and upgrading process units for full/deep conversion refinery include FCC and delayed coking process units. (3) A float case is assumed where crude properties and the refinery configuration (i.e., level of refining) determine the amount of gasoline and diesel produced. (4) Energy sources: hydrogen (H) via steam methane reforming (SMR) of natural gas (NG); refinery fuel gas (FG) from the crude and refining process units (RP) offsets NG consumption. FG is allocated through prioritizing the different NG requirements in the refinery (i.e., heat for processing, heat for steam, heat for SMR, and SMR feedstock) based on its heating value until it is exhausted. Heating values: 46.50 MJ/kg RFG low heating value (LHV) on mass basis and 47.14 MJ/kg NG LHV on mass basis.[58] Byproducts such as H via naphtha catalytic reforming (NCR) and coke deposited on FCC catalyst offset energy requirements as well. FCC regeneration must burn off the coke deposited on FCC catalyst to restore catalyst activity, which releases heat that satisfies most of the heat requirements of the FCC. FCC regeneration coke burned to complete combustion (coke yield 5.5 wt % FCC feed[35] and coke carbon content 85 wt %).[59] (5) Combustion GHG emissions factor is assumed the same for NG and FG combustion (56.6 g CO$_2$eq/MJ). H via NCR does not have any share of emissions due to allocation method employed. Electricity 100% coal-fired power (329 g CO$_2$ eq/MJ).[58] SI shows GHG emissions attributed to gasoline and diesel on a per MJ of product basis (Figure S5).

other final products is taken into account. In PRELIM, the default refinery configuration is set based on a set of three broad refinery categories: hydroskimming refinery, medium conversion refinery, and deep conversion refinery[46] as suggested by Marano.[47] All 10 refinery configurations in PRELIM fit into one of these three categories. The base case assigns each crude (OS and conventional) to the appropriate default refinery category, using API gravity and sulfur content of the whole crude as the criteria. Default process energy requirements are represented by literature values. A float case is assumed where crude properties and the refinery configuration determine the final product slate. When the alternative functional units are explored, refinery emissions are allocated to transportation fuels (i.e., gasoline, diesel, and jet fuel) on a hydrogen content basis (based on discussion in 19) across the scenarios. The SI details additional assumptions.

Four possible alternative refinery operating scenarios are created from a screening of parameters through sensitivity analysis and a collection of a range of plausible values for each parameter. These scenarios explore the impact of different refinery configurations available in PRELIM (crudes will not always end up in the default refinery configuration); variations in process energy requirements (greater efficiencies are possible than currently represented by the default values used); and, variations in fuel gas production calculations (a parameter that greatly varies throughout the industry).

Results are presented for a total of 12 assays out of the 29 present in PRELIM's assay inventory, selected to represent a range of qualities of crude for each category of crude (Table 1). For example, diluted bitumen is represented by "dilbit 2" and "syndilbit 1". These two assays are selected as they represent the highest and lowest overall refinery GHG emissions estimates respectively from the eight assays of diluted bitumen

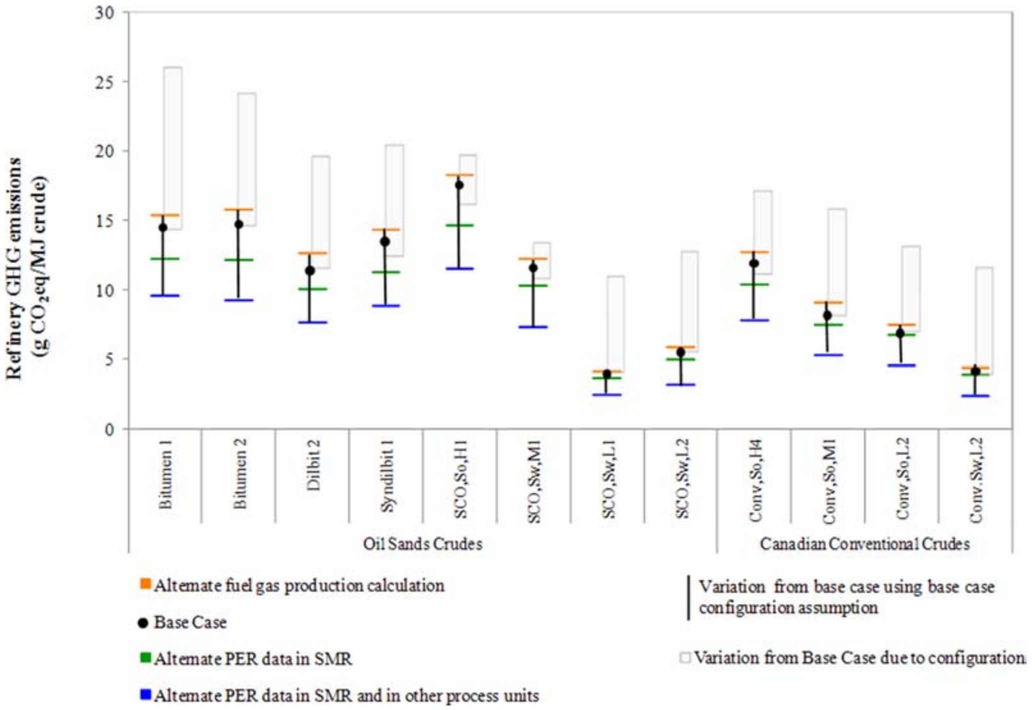

Figure 2. Scenario analysis overall refinery greenhouse gas (GHG) emissions. Scenarios: The base case represents the assumptions presented in Figure 1. Alternate process energy requirements (PER) data in steam methane reforming (SMR) uses a 91% energy efficiency as MJ hydrogen produced/MJ net energy use; energy use accounts for steam production inside SMR that is exported to other process units.[26] Alternate PER in SMR and in other process units simulate additional improvements on energy requirements in other refinery process units based on process energy use confidential data (overall efficiency improvement of approximately 30%). Alternate fuel gas production calculation assesses increasing refinery fuel gas production using an alternative calculation method to determine fuel gas production in hydrotreating process units. PRELIM uses a simple method to determine the amount of refinery fuel gas. The alternative calculation is based on hydrogen requirement specific to each crude while holding other base case assumptions constant that ends in high estimates in the amount of refinery fuel gas (average increase of 2.5% across all process units); variations in emissions are mainly associated with the hydrogen content of the total amount of refinery fuel gas. Variation from Base Case due to configuration defines range of GHG estimates associated with use of different refinery configurations while holding other base case assumptions constant. The SI shows scenario analysis estimates of GHG emissions attributed to gasoline and diesel on a per MJ of product basis (Figure S5).

in the assay inventory. Publicly available assay data are used for all OS assays with the exception of raw bitumen which is currently not processed directly in a refinery so data are not publicly available. The publicly available assays are streams or blends of crudes of different qualities flowing through pipelines in Canada. These streams were used to represent specific crude categories (e.g., diluted bitumen, SCO) through consultation with industry and academic experts to ensure that they represent an accurate range of characteristics for each category of OS-derived crudes. Conventional crudes are presented for the purposes of comparison. Table 1 provides a summary of all 12 assays, current production volumes of each crude category, source of data, and properties of the whole crude.

■ RESULTS

Base Case Results. Under the base case assumptions, total refinery energy use ranges from 0.06 to 0.24 MJ/MJ of crude (340−1400 MJ/bbl of crude). A detailed discussion of energy use is presented in SI. As expected, energy use has a positive linear relationship with the GHG emissions. The resulting GHG emissions of processing crudes of different qualities can vary widely, mainly due to differences in hydrogen requirements. Total refinery GHG emissions range from 4 to 18 g CO_2eq/MJ of crude being processed (23−110 kg CO_2eq/bbl of crude). For the 12 crudes considered in the base case, the supply of hydrogen contributes from 0 to 44% of refinery emissions, process heating contributes 26−71%, FCC catalyst regeneration contributes 0−17%, steam contributes 2−7%, and electricity contributes 10−21%. Up to 48% of the emissions associated with hydrogen requirements result from the chemical transformation of natural gas into hydrogen in the SMR process unit. Zero emissions from hydrogen supply are possible where hydrogen requirements are low enough to be met by coproduction of hydrogen via naphtha catalytic reforming. This form of hydrogen is considered to be a byproduct and therefore a CO_2eq emissions-free stream as the base case assumes that emissions are allocated only to final refinery products. Generally, the GHG emissions estimates from each energy type are proportional to their contribution to overall energy use with the exception of electricity, for which emissions are determined by the emissions intensity of electricity production (further discussion in SI).

Figure 1 shows that the amount of gasoline and diesel produced from the same amount of input (i.e., 100 000 barrels of crude) also varies with crude quality, but to different extents (further details in SI).

Alternative Scenario Results. Figure 2 presents the base case GHG emissions (also presented in Figure 1) for each crude as well as variation from the base case due to changes in assumptions regarding refinery configuration, process energy requirements, energy use for production of hydrogen via SMR, and refinery fuel gas production.

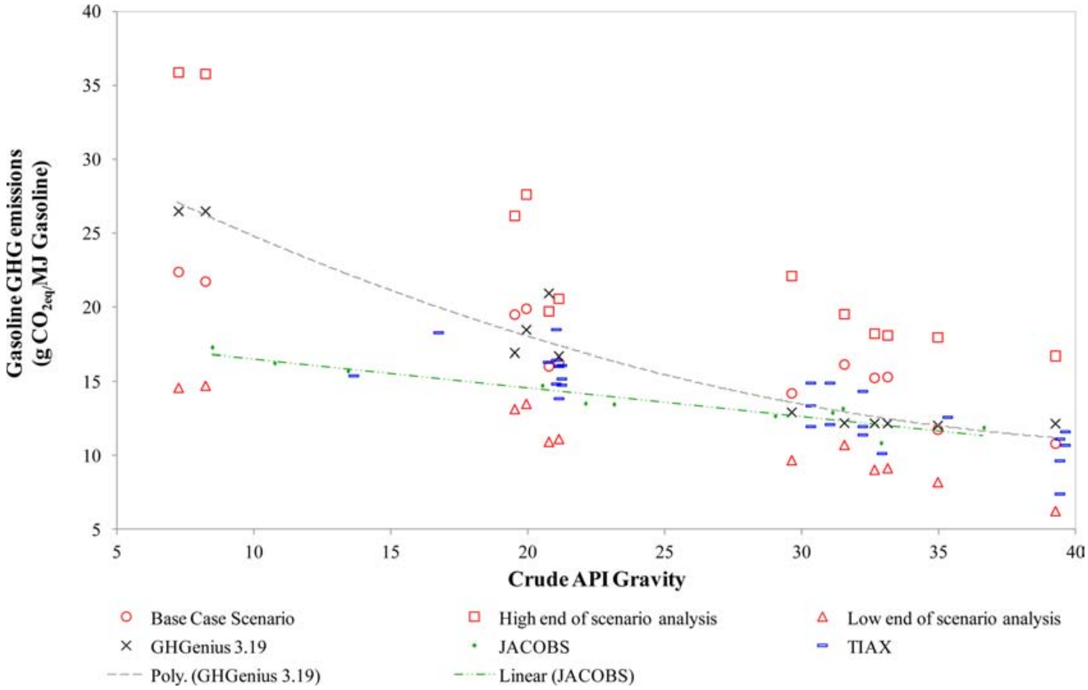

Figure 3. Comparison of GHGenius, JACOBS, TIAX, and PRELIM gasoline greenhouse gas (GHG) estimates. Base case estimates and variation from the scenario analysis presented in Figure 1. Variation from base case can be compared with variation in TIAX estimates;[17] TIAX study accounted for alternative configurations and/or energy efficiencies (i.e., different U.S. production regions). If PRELIM uses the same configuration as JACOBS[22] while holding other assumptions to base case constants, PRELIM replicates similar linear regression as JACOBS results suggest. GHGenius[60] estimates are from default GHGenius v.3.19 assumptions while varying API gravity and sulfur of crude using PRELIM assay inventory (polynomial regression built in GHGenius from crude slates of API > 25.4 and using Canadian industry forecast data). The GREET model emissions estimates are not included in the figure as there is no variation presented due to crude quality (the default gasoline carbon intensity is estimated at 10.5 g CO2eq/MJ of gasoline). Gerdes model estimates[25] and recent GHGenius estimates[61] using a linear relationship approach (which are not included in the figure) are also in the range of gasoline GHG emissions estimates resulting from the low end of the scenario analysis and TIAX as illustrated by Brandt.[49] These estimates are not included in the figure as they are either duplications of the same data or present very similar trends and ranges.

The magnitude of the impact on results from varying the refinery configuration is crude-specific but in general this factor has a greater impact than any other individual factor considered. When the full range of refinery configurations are run for each crude, the emissions can change as much as 12 g CO_2eq/MJ of crude (71 kg/bbl of Bitumen1) or up to 190% (Conv,Sw,L2: conventional sweet light crude 2 as indicated in Figure 2). Lighter and sweeter (lower in sulfur) crudes have increased GHG emissions above the base case since the base case assumes a simple hydroskimming configuration, and for heavier crudes (OS and conventional) there are deep conversion configurations in which the GHG emissions are higher or lower than those estimated in the base case. Therefore, the method used in the base case for assigning crudes to a default or "ideal" level of conversion is incomplete if the goal is to predict the full range of potential GHG emissions associated with refining a particular crude (as a crude could be processed in a variety of refineries with different configurations). Therefore, the specific refinery configuration and the associated process units play an important role.

Process unit energy requirements, as well as refinery fuel gas production, can vary significantly and collectively; this variation can result in a wide range of emissions estimates, implying that attention has to be placed on these assumptions and their implications for policy. Improving energy use in hydrotreating, FCC, naphtha catalytic reforming, delayed coking, and SMR process units (represented by real refinery operating data with higher levels of efficiency than the literature data used in the base case—overall efficiency improvement of approximately 30%) decrease GHG emissions by 34% (5 g CO_2eq/MJ of Bitumen1) to 43% (2 g CO_2eq/MJ of SCO,Sw,L2). Increasing the estimated production of refinery fuel gas (average increase of 2.5% across all process units) can increase GHG emissions by as little as 1% (0.02 g CO_2eq/MJ of SCO,Sw,L1) or as much as 10% (0.8 g CO_2eq/MJ of Conv,So,M1; up to 1 g CO_2eq/MJ of Bitumen 1). The SI details results of other scenarios.

As a whole, Figure 2 illustrates that a wider range of GHG emissions estimates is seen for OS products (2.5–26 g CO_2eq/MJ of crude) compared to conventional crudes (2.4–17 kg CO_2eq/MJ of crude). Generally, the highest estimates are for bitumen (9.3–26 kg CO_2eq/MJ of crude). This represents potential cases such as dilbit being sent to a refinery and the diluent being separated and returned to the OS operation. GHG emissions from refining diluted bitumen range between 7.6 and 20 g CO_2eq/MJ of crude. The SCOs represent one of the highest and the lowest GHG emissions of all crudes considered. The heavy SCO crude category can have GHG emissions as high as 20 g CO_2eq/MJ of crude. Light sweet SCO can have GHG emissions as low as 2.5 g CO_2eq/MJ of crude. Light/heavy crude differentials may provide an incentive for the production of light SCO; however, this differential can decrease in a market with increasing supply of heavy oil and refineries increasing their capabilities to manage that feedstock. The SI discusses PRELIM's SCO refinery GHG emissions estimates in detail. It is important to note that the high and low ends of the GHG emissions for OS crudes represent the cases of recycling of diluent (bitumen as a feedstock) and upgrading the bitumen prior to entering the refinery (high quality SCO) which have upstream processing requirements quite different from conventional crudes and will have different implications on a full LC basis.[48]

Alternative Functional Units. Given recent regulations such as the CA-LCFS, there has been increased interest in representing LC emissions on a per product basis. This requires allocation of total refinery emissions to each product. Assuming GHG emissions are allocated only to transportation fuels (i.e., gasoline, diesel, and jet fuel) on a hydrogen content basis (based on discussion in 19) across the scenarios, conventional crudes' gasoline GHG emissions estimates range from 6.2 to 22 g CO_2eq/MJ of gasoline, and OS products' GHG emissions estimates range from 9.0 to 36 g CO_2eq/MJ of gasoline. Diesel GHG emissions estimates for conventional crudes and OS products range from 2.3 to 26 g CO_2eq/of MJ of diesel and 3.3 to 36 g CO_2eq/MJ of diesel, respectively. Figure S5 illustrates gasoline and diesel GHG emissions estimates for the scenario analysis. The implications of different allocation methods are explored in the SI.

Overall refinery GHG emissions (i.e., per bbl or MJ of crude) will be greatly influenced by the refinery configuration employed. However, for some crudes, when the emissions are calculated on a per product basis (e.g., per MJ gasoline) the impact of the configuration can play a lesser role as the significant differences in emissions between configurations are tempered by the differences in the amount of product produced (Figure S5). For example, if light sweet SCO is processed in a deep conversion refinery instead of a hydroskimming refinery, it will undergo more intense processing and therefore result in both higher overall emissions as well as a higher volume of gasoline produced. This difference has implications in terms of potentially providing an incentive for one action (e.g., sell SCO to hydroskimming refinery) if the crude is being evaluated on an overall crude basis (i.e., all products) and a second action if it is evaluated on an individual product basis (e.g., sell SCO to deep conversion refinery).

Comparison with Other Studies. In the absence of a public-domain refinery modeling tool, the use of regression models based on sulfur content and API gravity of the whole crude is being generalized for the purposes of modeling crude quality effects on refinery GHG emissions.[49] Some studies assume a linear relationship[18,22,25] while others assume a quadratic relationship[15] for the regression model, and consensus has not yet been reached. The results reported by previous refinery models/studies are within the ranges calculated by the PRELIM model (Figures S6–S7). Figure 3 demonstrates that the degree of correlation between the gasoline GHG emissions estimates from refining and the whole crude API gravity is affected by assumptions about configuration and process energy requirements. This is also true for diesel (Figure S8). In addition, sulfur does not make a large contribution to predicting GHG emissions. PRELIM can replicate the results of previous studies when similar assumptions are made. However, the figure shows that previous studies do not provide the full range of emissions possible.

■ DISCUSSION

PRELIM goes beyond public LC-based modeling approaches by adding the detail required to evaluate the impact of crude quality and refinery configuration on energy use and GHG emissions of refining while remaining a transparent spreadsheet-based tool. The model is based on public data but is validated by confidential operating data and expert review. This approach allows for improved confidence in the model results while providing the detail required for users to replicate the results and make use of the framework. It provides more detailed calculations (e.g., includes a hydrogen balance at a process unit level) than current LC models but with less detail (thereby increasing manageability/transparency) than proprietary refinery energy optimization models. PRELIM is capable of replicating the findings from more complex models with an overall margin deviation below 10% in almost all cases, which is within the bounds of typical LC inventories.[41−43] PRELIM provides a data framework that can be integrated as a module in Well-To-Wheel models and used by academia, industry, and government to develop a consistent reporting structure for data in support of GHG emissions modeling for policy purposes.

Further model development should include the establishment of a statistical relationship between hydrogen content, aromatic hydrocarbon content, and the emissions intensity of processing a specific crude. The current assumption of processing all crudes to the same intermediate product specification may overestimate energy requirements for high quality crudes in medium and deep conversion refineries. Also, it is recommended that opportunities to improve the accuracy of hydrogen requirement estimates be explored. The inclusion of modeling crude input slates instead of individual crudes, economic data, and other environmental impacts, as well as tools for decision-making analysis such as Monte Carlo simulation, will enhance model capabilities.

The PRELIM application presented in this paper demonstrates that crude quality and the selected process units employed (i.e., the refinery configuration), as well as the energy efficiency of the process units, all play important roles in determining the energy requirements and emissions of processing a crude. The unique amount of hydrogen required to process each crude is dictated by the quality of the crude entering the refinery. It can be the major contributor to refinery energy use and GHG emissions for every crude. Therefore, this should be a key parameter used in estimating emissions. Emissions associated with providing the hydrogen required should also be the focus of emissions reductions at refineries.

This analysis provides insights that can help to inform emissions reductions decisions at refineries. Based on this analysis, the top three ways to reduce GHG emissions at refineries processing heavier crude will be to (1) reduce the amount of hydrogen consumed, (2) increase hydrogen production efficiency (and/or lower GHG emissions intensity of hydrogen production), and (3) capture CO_2 from the most concentrated, highest volume sources (i.e., FCC and SMR). All of these alternatives involve several technologies that require further study and can be included as new modules in future versions of PRELIM. Moreover, the results suggest that there may be a "preferred" configuration to process a specific crude. Opportunities for reductions in GHG emissions such as processing high quality crudes in low complexity refineries (hydroskimming and medium conversion) instead of deep conversion refineries could be investigated. However, these opportunities will be limited by the decreasing number of low complexity refineries in North America available to process these types of crude feedstocks. This serves as a reminder that the range of refinery emissions for OS products, as for other crudes, is linked to refining industry investments made over the next decade.

This analysis substantiates the claim that more accurate assessments of refinery emissions are required to better inform LC-based policies and avoid potential unintended consequences. Putting the refinery emissions variations into context, the variability in GHG emissions in the refining stage that results from processing crudes of different qualities is as significant as the magnitude expected in upstream operations (e.g., in this paper, the variability is up to 14 g CO_2eq/MJ of crude, or up to 11 g CO_2eq/MJ of gasoline and 19 CO_2eq/MJ of diesel—based on the full range of base case crudes). If crudes are run through the same configuration, refinery performance (defined by efficiency of energy use) introduces important variation. The PRELIM application demonstrated up to 43% deviation in the GHG emissions burden attributed to a crude solely by varying the efficiency of the process units in one configuration. This implies that impacts of crude quality and refinery configuration should be modeled in the refining stage of LC analyses of petroleum-based fuels. Also, climate policies based on LCA should equally engage both parts of the supply chain (i.e., crude production/processing/transport and refining stages) to encourage the most cost-effective GHG emissions mitigation pathways. Directives such as the current High Carbon Intensity Crude Oil (HCICO) provision in the CA-LCFS that do not explicitly include these differences in the definition and principles/goals could lead to unintended consequences.[50,51]

The results also show that API gravity and sulfur content of the whole crude are not sufficient to characterize the refinery energy use and GHG emissions specific to a crude. The use of these simple metrics within policies that are intended to differentiate the LC emissions of different crudes can also lead to unintended consequences. Energy efficiency of the process units and refinery configuration play a large role in explaining the variation in possible estimates. Ideally, the assay data like those presented in PRELIM should be collected and used as it improves accuracy beyond whole crude properties. However, since these data tend to be highly proprietary, we recommend that at minimum the crude distillation curve and the hydrogen content of the crude fractions be accounted for. Future efforts should focus on striking the balance between reporting the best data in a transparent way and protecting sensitive information. A starting point could be exploring the use of refining industry data and methods such as the Nelson index and/or Solomon energy efficiency index to simplify the characterization of refinery configurations;[52−55] however, an innovative approach will also be needed to represent crude quality parameters.

The PRELIM application shown in this paper demonstrates the strengths of detailed process modeling for understanding and assessing petroleum refinery GHG emissions sources with the ultimate goal of more informed decisions regarding the increased use of heavy oil in North America.

■ ASSOCIATED CONTENT

Ⓢ Supporting Information

Details on literature review, methods, and results. This material is available free of charge via the Internet at http://pubs.acs.org.

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Notes

The authors declare no competing financial interest.

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Crude Oil Assay Inventory [excerpts from "Prelim" database (www.ucalgary.ca/lcaost/prelim)] Page 1 of 4.

Brazil Lula_BG Group											
Assay #	57	**Cutoff Temp [°C]**	80	180	290	340	400	450	525	525	400
Property	Units	**Full Crude**	**LSR**	**Naphtha**	**Kerosene**	**Diesel**	**AGO**	**LVGO**	**HVGO**	**VR**	**AR**
Vol Flow	bpd	102,092	5,809	12,644	18,066	9,143	15,922	15,611	17,313	7,584	40,510
Vol Flow	m^3/d	16,232.60	924	2,010	2,872	1,454	2,532	2,482	2,753	1,206	6,441
Mass Flow	kg/d	13,995,180	629,783	1,539,470	2,379,181	1,259,566	2,239,229	2,239,229	2,519,132	1,119,614	5,877,976
Sulphur	wt%	0.27	0.05	0.00	0.11	0.22	0.30	0.38	0.44	0.50	0.43
Nitrogen	mass ppm	1119.63	0.0	0.0	83.2	449.2	856.4	1572.4	2390.9	3076.09	2209.6
API gravity	oAPI	29.3	75.81	53.10	39.17	31.65	28.32	25.20	22.97	20.76	23.40
Density	kg/m^3	880.20	681.88	765.77	828.27	866.43	884.50	902.13	915.14	928.44	912.57
Hydrogen	wt%	12.74	15.00	13.86	13.08	12.69	12.53	12.39	12.29	12.19	12.31
MCR	wt%	3.24								40.46	7.71
Characterization Factor	Kw (Approximate)	11.78	12.23	11.80	11.82	11.75	11.86	11.92	12.11	12.61	12.27
Tb(50%) weight basis	[°C]	345.00	50	138	250	315	370	420	485	620	510

Iraq Basra_BP											
Assay #	30	**Cutoff Temp [°C]**	80	180	290	340	400	450	525	525	400
Property	Units	**Full Crude**	**LSR**	**Naphtha**	**Kerosene**	**Diesel**	**AGO**	**LVGO**	**HVGO**	**VR**	**AR**
Vol Flow	bpd	101,031	9,036	16,592	15,984	7,981	8,678	7,522	9,221	26,016	42,683
Vol Flow	m^3/d	16,063.93	1,437	2,638	2,541	1,269	1,380	1,196	1,466	4,137	6,787
Mass Flow	kg/d	13,904,550	973,319	1,946,637	2,085,683	1,112,364	1,251,410	1,112,364	1,390,455	4,032,320	6,535,139
Sulphur	wt%	2.66	0.00	0.00	1.23	2.17	2.81	3.40	3.93	4.77	4.36
Nitrogen	mass ppm	798.48	0.0	0.0	28.1	294.8	558.3	856.9	1192.2	1836.77	1532.8
API gravity	oAPI	30.16192967	77.16	60.08	40.75	29.76	24.37	20.50	17.56	13.52	15.30
Density	kg/m^3	874.5	677.46	737.87	820.68	876.60	906.91	930.01	948.35	974.80	962.94
Hydrogen	wt%	12.52	15.54	14.48	13.16	12.93	12.28	11.81	11.48	11.03	11.26
MCR	wt%	6.33								21.81	13.47
Characterization Factor	Kw (Approximate)	12.06	12.44	12.12	11.74	11.58	11.57	11.62	11.74	12.05	11.90
Tb(50%) weight basis	[°C]	380	60	125	225	310	370	430	495	630	565

Albian Heavy Synthetic_Crude Monitor	SCO,So,H	AHS	Stream								
Assay #	1	**Cutoff Temp [°C]**	84.466	177.726	282.468	342.062	394.806	452.558	522.148	522.148	394.806
Property	Units	**Full Crude**	**LSR**	**Naphtha**	**Kerosene**	**Diesel**	**AGO**	**LVGO**	**HVGO**	**VR**	**AR**
Vol Flow	bpd	99,920	5,637	10,225	12,286	7,233	9,877	10,428	13,761	30,473	53,967
Vol Flow	m^3/d	15,887.23	896	1,626	1,953	1,150	1,570	1,658	2,188	4,845	8,581
Mass Flow	kg/d	14,886,832	595,473	1,190,947	1,637,552	1,042,078	1,488,683	1,637,552	2,233,025	5,061,523	8,932,099
Sulphur	wt%	2.24	0.00	0.26	1.09	1.43	1.64	1.93	2.39	3.72	3.06
Nitrogen	mass ppm	2581.33	0.0	0.0	29.0	733.4	1390.2	2203.4	3116.3	4935.20	3979.6
API gravity	oAPI	19.48134328	81.26	61.48	37.13	24.51	17.62	11.64	7.01	3.82	4.30
Density	kg/m^3	936.2787443	664.43	732.53	838.28	906.09	947.98	987.60	1020.58	1044.65	1040.95
Hydrogen	wt%	10.72	16.01	14.76	12.88	12.19	11.21	10.30	9.57	8.65	9.18
MCR	wt%	10.90078261								32.03	18.17
Characterization Factor	Kw (Approximate)	11.64	12.64	12.28	11.65	11.28	11.08	10.94	10.88	11.30	10.95
Tb(50%) weight basis	[°C]	447.934	56.754	131.97	245.37	321.318	372.956	429.496	490.614	643.4122449	551.7

Crude Oil Assay Inventory [excerpts from "Prelim" database (www.ucalgary.ca/lcaost/prelim)] Page 2 of 4.

Cold Lake_Crude Monitor	Dilbit	CL	Stream							
Assay#	4	**Cutoff Temp [°C]**	84.85108696	172.373913	284.0402174	341.4423913	395.0586957	451.2565217	519.0554348	519.0554348	395.0586957
Property	Units	**Full Crude**	**LSR**	**Naphtha**	**Kerosene**	**Diesel**	**AGO**	**LVGO**	**HVGO**	**VR**	**AR**
Vol Flow	bpd	101,435	12,417	8,818	10,710	7,073	8,875	7,778	10,529	35,235	52,917
Vol Flow	m^3/d	16,128.13	1,974	1,402	1,703	1,125	1,411	1,237	1,674	5,602	8,414
Mass Flow	kg/d	14,764,716	1,181,177	1,033,530	1,476,472	1,033,530	1,328,824	1,181,177	1,624,119	5,905,886	8,711,183
Sulphur	wt%	3.89	0.00	0.09	1.43	2.09	2.61	3.14	3.91	6.68	5.68
Nitrogen	mass ppm	2200.95	0.0	0.0	28.7	249.6	550.6	956.1	1665.5	4678.43	3612.0
API gravity	oAPI	20.73007813	104.79	60.26	31.53	22.32	18.61	16.51	14.21	2.60	5.04
Density	kg/m^3	928.598502	598.26	737.16	867.07	918.99	941.72	955.07	970.18	1054.17	1035.34
Hydrogen	wt%	11.19	18.86	14.71	12.21	11.84	11.38	11.14	10.90	8.72	9.46
MCR	wt%	10.62700535								26.54	18.01
Characterization Factor	Kw (Approximate)	11.79	13.92	12.28	11.28	11.12	11.17	11.29	11.45	11.27	11.25
Tb(50%) weight basis	[°C]	457.673913	48.50217391	140.3641304	248.6804348	320.6956522	375.2913043	426.2891304	490.5913043	661.786747	606.8086957

Husky Synthetic Blend_Crude Monitor	SCO,Sw,L	HSB	Stream							
Assay #	5	**Cutoff Temp [°C]**	91.20833333	177.4222222	290.6416667	342.6805556	399.6166667	455.0166667	526.4805556	526.4805556	399.6166667
Property	Units	**Full Crude**	**C5s**	**Naphtha**	**Kerosene**	**Diesel**	**AGO**	**LVGO**	**HVGO**	**VR**	**AR**
Vol Flow	bpd	99,990	3,733	7,964	27,113	18,871	18,284	14,035	8,214	1,778	24,110
Vol Flow	m^3/d	15,898.46	594	1,266	4,311	3,000	2,907	2,232	1,306	283	3,833
Mass Flow	kg/d	13,694,379	410,831	958,607	3,560,539	2,601,932	2,601,932	2,054,157	1,232,494	273,888	3,560,539
Sulphur	wt%	0.09	0.06	0.04	0.02	0.05	0.09	0.18	0.31	0.10	0.22
Nitrogen	mass ppm	349.74	0.0	0.0	40.4	191.4	401.4	726.2	1200.7	481.00	871.6
API gravity	oAPI	32.62820513	72.74	55.23	39.65	31.51	26.44	22.07	18.29	14.39	20.69
Density	kg/m^3	861.2817181	692.12	757.05	825.94	867.19	895.02	920.52	943.71	968.97	928.81
Hydrogen	wt%	12.87	15.04	14.17	13.20	13.20	12.59	12.05	11.58	11.95	11.88
MCR	wt%	0.060416667								3.02	0.23
Characterization Factor	Kw (Approximate)	11.91	12.21	12.02	11.84	11.76	11.73	11.72	11.73	11.78	11.72
Tb(50%) weight basis	[°C]	328.7472222	63.38611111	147.2138889	248.0277778	317.9638889	371.325	426.3777778	483.4305556	556.5055556	445.8944444

Seal Heavy_Crude Monitor	Dilbit	SH	Stream							
Assay #	14	**Cutoff Temp [°C]**	80.33214286	169.3714286	284.4464286	339.6821429	393.9107143	452.5214286	522.175	522.175	393.9107143
Property	Units	**Full Crude**	**LSR**	**Naphtha**	**Kerosene**	**Diesel**	**AGO**	**LVGO**	**HVGO**	**VR**	**AR**
Vol Flow	bpd	100,406	8,855	11,207	12,947	6,102	7,918	6,785	8,565	38,026	51,478
Vol Flow	m^3/d	15,964.55	1,408	1,782	2,059	970	1,259	1,079	1,362	6,046	8,185
Mass Flow	kg/d	14,774,632	886,478	1,329,717	1,772,956	886,478	1,181,971	1,034,224	1,329,717	6,353,092	8,717,033
Sulphur	wt%	5.14	0.00	0.14	2.14	2.98	3.54	4.18	4.90	8.55	7.47
Nitrogen	mass ppm	1978.54	0.0	0.0	0.0	195.3	447.3	842.0	1363.8	4068.27	3273.0
API gravity	oAPI	20.62790698	93.01	57.94	32.64	23.23	19.08	15.96	13.27	3.03	1.23
Density	kg/m^3	929.2221612	629.65	746.20	861.24	913.62	938.79	958.65	976.44	1050.77	1065.00
Hydrogen	wt%	10.60	17.27	14.33	12.29	11.98	11.44	11.06	10.73	7.95	8.75
MCR	wt%	9.384722222								21.80	15.91
Characterization Factor	Kw (Approximate)	11.83	13.18	12.06	11.31	11.15	11.18	11.28	11.37	11.41	11.05
Tb(50%) weight basis	[°C]	467.3321429	45.29285714	133.3464286	241.3892857	316.3535714	370.8142857	430.8428571	490.1857143	686.975	636.0678571

Crude Oil Assay Inventory [excerpts from "Prelim" database (www.ucalgary.ca/lcaost/prelim)] Page 3 of 4.

Suncor Synthetic A_Crude Monitor	SCO,Sw,L	OSA	Stream							
Assay #	12	**Cutoff Temp [°C]**	84.84210526	179.5368421	289.4052632	343.9342105	400.3657895	457.1710526	533.7842105	533.7842105	400.3657895
Property	Units	**Full Crude**	**C5s**	**Naphtha**	**Kerosene**	**Diesel**	**AGO**	**LVGO**	**HVGO**	**VR**	**AR**
Vol Flow	bpd	99,885	4,978	14,653	24,626	19,472	18,874	11,929	4,474	880	17,328
Vol Flow	m^3/d	15,881.76	791	2,330	3,916	3,096	3,001	1,897	711	140	2,755
Mass Flow	kg/d	13,654,443	546,178	1,775,078	3,277,066	2,730,889	2,730,889	1,775,078	682,722	136,544	2,594,344
Sulphur	wt%	0.16	0.01	0.01	0.04	0.13	0.23	0.38	0.62	0.10	0.43
Nitrogen	mass ppm	488.71	8.9	3.8	125.9	381.6	686.7	1147.4	1832.1	321.13	1284.1
API gravity	oAPI	33.10824742	73.34	54.04	37.40	28.76	23.84	19.55	15.78	13.28	18.63
Density	kg/m^3	858.769987	690.10	761.88	836.93	882.08	910.00	935.85	959.81	976.36	941.61
Hydrogen	wt%	12.70	14.95	13.94	12.90	12.81	12.20	11.65	11.16	11.82	11.53
MCR	wt%	0.022916667								2.29	0.12
Characterization Factor	Kw (Approximate)	11.86	12.16	11.89	11.66	11.56	11.53	11.52	11.55	11.59	11.53
Tb(50%) weight basis	[°C]	315.0105263	55.72368421	141.1657895	244.1210526	317.6631579	370.1263158	425.6421053	485.5868421	533.7842105	439.1921053

Syncrude Synthetic_Crude Monitor	**SCO,Sw,L**	**SYN, SSB**	**Stream**							
Assay #	17	**Cutoff Temp [°C]**	80.04	177.08	290.64	342.22	397.58	451.91	521.41	521 +	398 +
Property	Units	**Full Crude**	**C5s**	**Naphtha**	**Kerosene**	**Diesel**	**AGO**	**LVGO**	**HVGO**	**VR**	**AR**
Vol Flow	bpd	99,796	3,703	12,478	26,897	16,704	16,206	13,004	8,161	2,643	23,893
Vol Flow	m^3/d	15,867.60	589	1,984	4,277	2,656	2,577	2,068	1,298	420	3,799
Mass Flow	kg/d	13,786,921	413,608	1,516,561	3,584,599	2,343,777	2,343,777	1,930,169	1,240,823	413,608	3,584,599
Sulphur	wt%	0.14	0.01	0.00	0.01	0.08	0.16	0.29	0.48	0.35	0.36
Nitrogen	mass ppm	487.44	0.0	0.0	45.1	271.1	570.4	1015.9	1702.5	1240.05	1279.4
API gravity	oAPI	31.5	69.73	53.44	37.15	28.69	23.91	19.93	16.32	12.13	18.31
Density	kg/m^3	867.10	702.50	764.37	838.19	882.45	909.58	933.52	956.28	984.19	943.58
Hydrogen	wt%	12.55	14.63	13.84	12.86	12.80	12.21	11.70	11.24	11.30	11.49
MCR	wt%	0.05								1.72	0.20
Characterization Factor	Kw (Approximate)	11.78	12.02	11.83	11.64	11.56	11.54	11.54	11.56	11.65	11.55
Tb(50%) weight basis	[°C]	320.99	63	139	244	318	370	423	480	566	447

Western Canadian Select_Crude Monitor	Syndilbit	WCS	**Stream**							
Assay #	20	**Cutoff Temp [°C]**	78.62	175.17	289.93	339.77	393.55	451.35	524.06	524 +	394 +
Property	Units	**Full Crude**	**LSR**	**Naphtha**	**Kerosene**	**Diesel**	**AGO**	**LVGO**	**HVGO**	**VR**	**AR**
Vol Flow	bpd	100,306	6,197	8,855	13,033	9,199	8,974	8,841	10,648	34,559	53,786
Vol Flow	m^3/d	15,948.60	985	1,408	2,072	1,463	1,427	1,406	1,693	5,495	8,552
Mass Flow	kg/d	14,783,214	591,329	1,034,825	1,773,986	1,330,489	1,330,489	1,330,489	1,626,154	5,765,453	8,722,096
Sulphur	wt%	3.38	0.00	0.26	0.96	1.52	1.99	2.53	3.24	6.01	4.97
Nitrogen	mass ppm	1998.50	0.0	0.0	49.5	221.6	468.9	844.2	1457.9	4343.75	3271.9
API gravity	oAPI	20.5	104.04	60.83	33.63	23.90	20.11	17.86	15.67	3.23	7.10
Density	kg/m^3	929.76	600.16	734.98	856.08	909.67	932.42	946.44	960.52	1049.25	1019.89
Hydrogen	wt%	11.21	18.75	14.76	12.40	12.07	11.60	11.36	11.13	9.12	9.84
MCR	wt%	9.36								23.97	15.86
Characterization Factor	Kw (Approximate)	11.74	13.87	12.30	11.37	11.19	11.24	11.37	11.52	11.35	11.37
Tb(50%) weight basis	[°C]	451.35	48	138	240	314	369	422	482	668	595

Crude Oil Assay Inventory [excerpts from "Prelim" database (www.ucalgary.ca/lcaost/prelim)] Page 4 of 4.

Alaskan North Slope_Exxon	Conv,So,L	ANS									
Assay #	23	**Cutoff Temp [°C]**	80.00	178.00	287.00	342.00	399.00	450.00	523.00	523 +	399 +
Property	Units	**Full Crude**	**LSR**	**Naphtha**	**Kerosene**	**Diesel**	**AGO**	**LVGO**	**HVGO**	**VR**	**AR**
Vol Flow	bpd	101,197	9,489	17,342	16,512	7,858	7,690	6,626	8,420	27,259	42,843
Vol Flow	m^3/d	16,090.29	1,509	2,757	2,625	1,249	1,223	1,054	1,339	4,334	6,812
Mass Flow	kg/d	13,810,740	966,752	2,071,611	2,209,718	1,104,859	1,104,859	966,752	1,242,967	4,143,222	6,352,940
Sulphur	wt%	0.85	0.00	0.00	0.25	0.59	0.85	1.12	1.39	1.63	1.50
Nitrogen	mass ppm	908.14	0.0	0.0	36.4	355.7	673.2	1071.1	1548.1	2018.95	1782.6
API gravity	oAPI	31.4	89.12	56.66	36.45	28.35	24.95	22.55	20.76	16.38	20.07
Density	kg/m^3	868.60	640.75	751.29	841.68	884.31	903.56	917.61	928.42	955.94	932.61
Hydrogen	wt%	12.81	16.24	14.37	13.30	12.94	12.72	12.41	11.91	11.34	11.61
MCR	wt%	4.86								16.18	10.57
Characterization Factor	Kw (Approximate)	11.67	12.81	11.88	11.50	11.51	11.61	11.74	11.89	12.24	11.96
Tb(50%) weight basis	[°C]	305.61	35	123	232	315	370	424	477	620	500

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CARBON FOOTPRINTING

Factors driving refinery CO_2 intensity, with allocation into products

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Abstract

Background and scope Attempts to develop adequate allocation methods for CO_2 emissions from petroleum products have been reported in the literature. The common features in those studies are the use of energy, mass, and/or market prices as parameters to allocate the emissions to individual products. The crude barrel is changing, as are refinery complexities and the severity of conversion to gasoline or diesel leading to changes in the emissions intensity of refining. This paper estimates the consequences for CO_2 emissions at refineries of allowing these parameters to vary.

Materials and methods A detailed model of a typical refinery was used to determine CO_2 emissions as a function of key operational parameters. Once that functionality was determined, an allocation scheme was developed which calculated CO_2 intensity of the various products consistent with the actual refinery CO_2 functionality.

Results The results reveal that the most important factor driving the refinery energy requirement is the H_2 content of the products in relation to the H_2 content of the crude. Refinery energy use is increased either by heavier crude or by increasing the conversion of residual products into transportation fuels. It was observed that the total refinery emissions did not change as refinery shifted from gasoline to diesel production.

Discussion The energy allocation method fails to properly allocate the refinery emissions associated with H_2 production. It can be concluded that the reformer from a refinery energy and CO_2 emissions standpoint is an energy/CO_2-equalizing device, shifting energy/CO_2 from gasoline into distillates. A modified allocation method is proposed, including a hydrogen transfer term, which would give results consistent with the refinery behavior.

Conclusions The results indicate that the refinery CO_2 emissions are not affected by the ratio of gasoline to distillate production. The most important factors driving the CO_2 emissions are the refinery configuration (crude heaviness and residual upgrading) which link to the refinery H_2 requirement. Using the H_2-energy equivalent allocation proposed in this study provides a more reliable method to correctly allocate CO_2 emissions to products in a refinery in a transparent way, which follows the ISO recommendations of cause-effect and physical relationship between emissions and products.

Recommendations and perspectives Regulatory activity should recognize that there is no functional relationship between refinery CO_2 emissions and the production ratio of gasoline, jet, and diesel, and adopt a methodology which more accurately mirrors actual refinery behavior.

Keywords CO_2 allocation methods · Carbon footprint · Crude oil refining CO_2 emissions · Diesel production · Energy-consuming products · Gasoline production · H_2 effects on refinery CO_2 · Life cycle assessment · Refining emissions

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1 Background, aim, and scope

Policy makers and regulators are seeking to impose greenhouse gases (GHG) performance standards on fuel lifecycles, e.g., California's Low Carbon Fuel Standard (LCFS 2007) and the European Union's Fuels Quality and Renewables Directives (COD 2008). The common feature of these regulations is that fuel providers will be required to track the lifecycle (i.e., well to wheels) GHG emissions intensity of their products, measured per unit of fuel energy, and reduce this value over time. Furthermore, the US Environmental Protection Agency is assessing fuel lifecycle GHG emissions intensities for the Energy Information and Security Act. Models describing emissions in the fuel lifecycle, which were designed to meet academic scenario forecasting needs, now have to be redesigned to suit regulatory applications, with the associated legal and commercial implications.

Crude oil based transport fuels are produced concurrently with other fuel and non-fuel products. Consequently, overall CO_2 emissions generated by the refining process can be distributed between the individual products through "allocation" rules. Historically, such rules have reflected the scope and goals of the study, the modeler's understanding of the process, the available data and end-use options for the products because there is no theoretical basis for choosing one allocation scheme over another. When some refining products are regulated on their carbon content but not others, it is important to ensure that the allocation rules reflect the actual climate impacts of the regulated products as fairly as possible, whilst at the same time, minimizing incentives to transfer responsibility for the impacts onto unregulated products.

The International Standard Organization (ISO) guidelines for lifecycle assessment (LCA) recommend that allocation should be avoided wherever possible, but where this is not possible, the allocation should reflect quantitatively or qualitatively how environmental impact changes with product yield. Some authors have suggested options to refine the ISO methodology and the accuracy of the results (Ekvall and Finnveden 2001). Ultimately, however, it is left to the LCA practitioner to decide how to follow these recommendations. As a result, the literature contains several different estimates for the carbon intensity of gasoline and diesel production even for similar systems (Furuholt 1995).

The problems faced in solving the issue of allocation in multi-product systems are fairly well known, and they have been extensively discussed in the literature (Azapagic and Clift 1999; Ekvall 1999; Babusiaux 2003; Ekvall and Weidema 2004). Different accounting schemes have been proposed to assign emissions to the plant products typically based on mass, energy, or market value shares of products. More recently, linear programming (LP) models, which have a long tradition in the refining industry (Charnes et al. 1952; Griffin 1972; Palmer et al. 1984), have been extended to calculate CO_2 emissions, and to assign individual product contributions to the CO_2 emissions in refineries through a marginal approach (Azapagic and Clift 1999; Babusiaux 2003). These models follow a similar logic to that used in assigning costs to refinery products: global CO_2 emissions are allocated to products based on the incremental CO_2 emissions generated in manufacturing an additional volume of the products. The resulting product CO_2 intensities are sometimes, but not always, different from those estimated under traditional mass/energy allocation schemes. Neither type of method is superior; but each has its domain of validity and applicability.

Furuholt (1995) compared the energy consumption and pollutant emissions in the production and end use of regular gasoline, gasoline with MTBE, and diesel. Energy consumption and emissions were tracked through the production chain and emissions were allocated to products based on their energy content. The results were highly sensitive to the product specifications, and it was predicted that emissions from diesel production were significantly lower than those from production of gasoline as a consequence of "diesel's lower process energy requirement".

Wang and coworkers (Wang et al. 2004) compared the impact of different allocation rules applied at the process unit level in a US refinery. They used as an archetype refinery a detailed quantitative process-step model of petroleum refining developed in the late 1970s at Drexel University (Brown et al. 1996). The mass and energy balances at each process step of this archetype constitute the reference process-step model for petroleum refineries (Ozalp and Hyman 2007). Wang et al. (2004) compared the use of mass, energy content, and market value share of final and intermediate petroleum products as allocation weight factors at the process unit and the refinery levels. They defined product energy intensities for major refinery products (defined as the fraction of process energy invested in producing a particular product relative to its weight factor), and concluded that wherever possible, energy use allocation should be made at the lowest sub-process level (Wang et al. 2004). They found diesel production to be less energy intensive than gasoline production in each of the allocation weighting methods used (mass/energy/market value; refinery/process unit level) as predicted by Furuholt (Furuholt 1995).

Tehrani (Tehrani 2007) used an LP model to study the CO_2 emissions allocation problem for a European price-taking refinery operating in a cost-minimizing environment. It was assumed that the refiner's objective is to satisfy a petroleum production target at the minimum cost and subject to constraints of prevailing technology, commodity prices, input availabilities, oil product demand, capacity constraints, material balance, and product quality. Tehrani concluded that emissions could be allocated among products using "average allocation" coefficients containing two contributions, a direct one, which is its marginal CO_2 intensity, and an indirect contribution, which depends upon the production elasticity of unit processes and is calculated at the LP optimal solution ex-post. This approach was later used (Tehrani and Saint-Antonin 2007) to assess the impact of reducing sulfur in European automotive fuels on the refining emissions intensity of gasoline and diesel. It was shown that, contrary to prior results (Furuholt 1995; Wang et al. 2004), gasoline refining could be less emissions intensive than diesel refining.

Pierru (2007) used an alternative LP optimization function including operating costs and cost associated with the refinery's CO_2 emissions to calculate the marginal emissions (in accordance with economic theory) from the various refinery products. The study highlights the impact of constraints such as demand, refinery capacity, and raw material supply on the CO_2 emissions originated at refineries. It was concluded that contrary to traditional LCA studies, diesel has a higher marginal contribution to refinery emissions than gasoline.

The common features in the above studies, notwithstanding the different approaches, constraints, and results are: single-fixed refinery configuration, fixed unit throughput capacities and fixed crude diet.

The crude barrel is changing, as are fuel specifications, and these will lead to changes in refining emissions intensities. In this paper, we therefore focus on the consequences of varying the crude diet, the severity of conversion to gasoline or diesel, and the complexity of the refinery. The critical element is the hydrogen requirement, since its production and consumption is highly carbon intensive. A detailed analysis of the hydrogen flow through the refinery is carried out at each refinery unit, in order to establish the carbon footprint of products. Based on this work, we propose a more realistic way to estimate the energy and emissions intensities of refinery products.

2 Materials and methods

The refinery simulation model is a case study model used by Shell to select crude type, determine refinery products, and calculate refinery economics for major investment decisions. Shell has high confidence in its accuracy.

Yield representations reflect crude boiling curve, hydrogen content, aromaticity, sulfur, nitrogen, and other relevant parameters associated with the refinery crude diet. Several of those terms (boiling curve, hydrogen content, and aromaticity) are at least partially covariant with crude density (API gravity), but it is more accurate to handle them individually. Processing severity can be adjusted by distributing feeds differently within the refinery flow matrix, by changing reactor severity of individual processes, and by varying fractionator cut points. Energy consumption was determined by summing feed-rate-based consumption factors for each process unit (some of which are functions of that unit's severity). Feed gas and fuel gas energy for H_2 manufacture are included. Hydrogen balance is maintained throughout the model, meaning the hydrogen contained in all feeds equals the hydrogen contained in all products from each unit. Relatively few refinery models have that feature; meaning that their prediction of how much hydrogen is required from the hydrogen plant is less reliable. Since hydrogen plant size is critical to refinery CO_2 emissions, this is an important advantage for this study.

Specific process units included were: crude distillation, delayed coking, fluid catalytic cracking, hydrocracking, naphtha reforming, alkylation, hydrotreating (naphtha, distillates, fluid catalytic cracking (FCC) feed), hydrogen manufacture, sulfur recovery, and various other enabling process units typically included in a refinery (the refinery flow chart is available as Online Resource 1).

Product specifications were gasoline was US reformulated gasoline in a typical grade mix of regular to premium. Diesel was US ultra low sulfur diesel. Jet was Jet-A, and in cases where produced, residual was US Gulf Coast high sulfur Fuel Oil #6. Naphtha from the catalytic cracker was hydrotreated such that gasoline pool sulfur was 25 ppm. Jet smoke and diesel cetane number using a normal severity distillate hydrotreating unit were inside fuel specifications for all except two of the crudes analyzed. This was ignored because real refineries have some scope to blend streams to meet specifications, and if not, the refinery would run a blend of crude rather than neat crude. The three low value residual streams (Cat slurry, Fuel Oil #6 and Coker Coke) were summed into a single product class called residual/coke. To summarize, the product streams considered were liquefied petroleum gas (LPG), gasoline, distillate (including gasoil and kerosene), and residual/coke.

It was considered critical that the results from the allocation methods and the results from the model runs be consistent. In other words, if the refinery runs showed no difference in total refinery CO_2 emissions as the gasoline to diesel ratio was varied, then the CO_2 intensity of those two fuels should be the same.

3 Results

Three issues were studied explicitly: crude heaviness (fraction boiling >1,000°F/540°C), production ratio of gasoline to distillates, and whether the refinery processed its 1,000°F/540°C+vacuum resid in a delayed coker or blended it to Fuel Oil no. 6. Issues such as ratio of FCC to hydrocracking capacity, the type of benzene production controls employed, whether C_5/C_6 isomerization is employed, in cases with residue reduction, whether the residue reduction unit was a delayed coker, other type of coker, or other type of unit such as LC-Finer or resid hydrotreater, and any number of similar configurational issues could perturb the numerical results. Pair cases simulations (base Vs base + δ), where δ refers to a perturbation on the variable under analysis were run to assess the robustness of the results and to ensure that they did not have a material impact on the conclusion reached through the study

3.1 Matrix of cases

Crude heaviness was studied by selecting six crudes with quantity of vacuum bottoms (>550°C) ranging from 10% to 35% (lightest Brent, heaviest Maya). Production ratio of gasoline to distillate was varied by shifting from gasoline to distillate mode which means lowering FCC and HCU reactor severities, and changing cut points at crude unit, cat cracker, and hydrocracker. Cut points were shifted on both ends, lowering naphtha/distillate cut point and raising distillate to FCC feed cut point. Production of resid was changed by shutting down the coker, and sending coker feed to #6 oil blending instead. Case names of these conditions were captured in a four character code. The first character was either K or 6, representing a coker case or a case that produced #6 residual fuel oil. The second and third characters were C for crude, and a number, meaning the crude heaviness choices from 1 to 6. The final case was H or L meaning high or low severity to gasoline. So for example, KC3L was a coker case on crude 3, with low severity to gasoline. Or case 6C5H was a #6 fuel oil case on crude 5 with high severity to gasoline. In all, the refinery was run in four modes (high/low gasoline, with/without coker) with six different crudes to produce a matrix of 24 data points. For each case, refinery yields and fuel/CO_2 data were generated. Refinery yields data are available as Online Resource 2. The fuel/CO_2 data were split by process needs and H_2 generation needs.

One aspect of these runs was different from typical model running strategy. In most model studies, one must stay within capacity constraints of the various process units. But in this study, there are wide variations of crude heaviness, which would far exceed the acceptable flow rate variations for individual units in any given refinery. So individual process unit throughputs were allowed to vary as needed, such that each intermediate stream in the refinery headed to its normal consuming unit. Had that not been done, the results would have been strongly and inappropriately biased by internal constraints. This way, it was as though each case had a custom tailored refinery to allow ideal flows for that case.

3.2 Numerical results

Consider the results as being four blocks of data, with six cases in each block. The four blocks are with/without coker (i.e., high/low resid production), high/low conversion to gasoline, and within each of those four blocks, the six crudes of varying heaviness. These four blocks are shown in Fig. 1.

Comparing the left two with the right two blocks on Fig. 1 shows that adding the coker to eliminate the no. 6 fuel oil production clearly increases CO_2 emissions for all case pairs involving that switch. Not only does the coker consume energy in its own right, it upgrades a low hydrogen content product stream (no. 6 fuel oil). This in turn requires the refinery to run other cracking and hydrogen consuming units harder to boost the hydrogen content up from resid hydrogen levels (because resid is no longer being produced) to mogas/jet/diesel hydrogen levels (because those higher hydrogen content products are being produced instead of resid).

Changing the severity and cut points to vary the ratio of gasoline to distillate has very little effect in any of the cases in any of the case pairs where that change was made (see Fig. 1). At first, this might seem illogical because to go to lower boiling point gasoline, the level of cracking needed is harder, and that would seem to require more energy. The counter-balancing point is H_2 content. In gasoline production, aromatics are favored due to higher octane ratings and this is where the reformer's H_2 production comes into play. To make more gasoline, reformer feed rate increases and as reformers also produce H_2, the amount of H_2 that must be made in the CO_2 intensive H_2 plant decreases, and on balance, the overall CO_2 emissions do not change very much. In contrast, for jet and diesel production, paraffins are favored. In fact, despite its lower boiling point, H_2 content of gasoline is similar to jet and diesel.

What happens with crude heaviness depends on whether there is a coker (or other residue reduction unit). The left two blocks of Fig. 1 show that if there is a coker to eliminate resid, heavier crude needs a bigger coker, which consumes more energy, and demands more hydrogen consumption in downstream units, thus increasing CO_2 emissions (from running the hydrogen plant at a higher rate). The right two blocks of Fig. 1 show that without a coker, the refinery produces resid as a product, so CO_2 emissions do not change very much with crude heaviness. However, the heavier crude makes more resid in comparison to transportation fuel, and that is an indirect CO_2 penalty because more carbon intensive resid product fuels

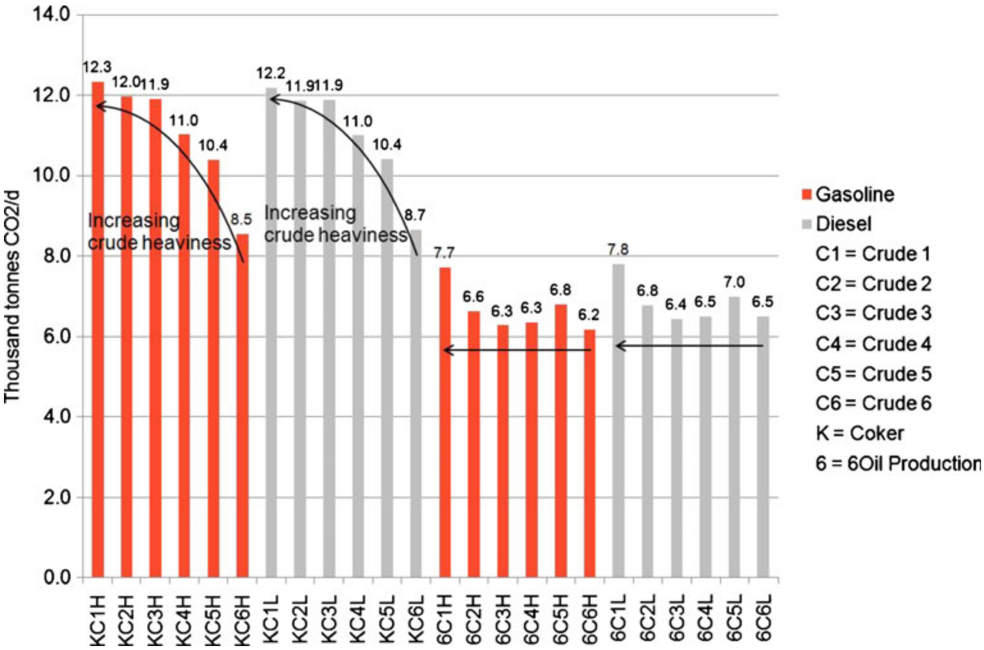

Fig. 1 Overall refinery CO_2 emissions

are being produced. Note that this issue of with/without coker, or higher/lower residual fuel production is sometimes referred to as refinery complexity. The coker (or other residue reduction unit) adds complexity not only because it is an added large process unit, but also because products from residue reduction units are low quality, which requires other units within the refinery to be larger and higher severity in order to upgrade them.

The fact that CO_2 emissions are practically independent of light product ratio shifts from gasoline to diesel shows that the CO_2 emissions at refinery level are not driven by the differential energy demands of these products, but by other factors: crude heaviness and whether the refinery has a coker to eliminate production of residual fuel. A third route to CO_2 emissions reductions is energy conservation; all routes can be influenced by external issues such as crude availability, product demands, and prices.

4 Discussion

It was shown in Section 3 that two operational routes significantly lowered total refinery CO_2 emissions. The production ratio of gasoline to diesel fuel was not one of those factors, because interaction of some non-obvious hydrogen issues equalizes the total refinery CO_2 emissions from production of gasoline and diesel fuel. The hydrogen balance at the refinery, together with the results from tracking products through process units in terms of the energy consumed during their production and their associated CO_2 emissions are described in the next sections. Both results are used to develop an allocation strategy consistent with refinery CO_2 emissions behavior.

4.1 Hydrogen balance

One of the most critical factors in refining is hydrogen balance. This is not just hydrogen balance in the sense of flows of elemental hydrogen gas as a processing stream but also the hydrogen content of feeds and products. Since crude oil is generally low in hydrogen content, and refined products (except for residual fuel and coke) are high in hydrogen content, refineries are forced to produce the additional H_2 that satisfies their needs in a process that its intrinsically highly CO_2 emissions intensive.

Carrying this hydrogen issue a bit further, if the crude has less hydrogen coming in (most common explanation being that it is heavier), or the products have more hydrogen going out (most common explanation being more transportation fuel with correspondingly less residual fuel), the refinery energy consumption will invariably be higher. While it is true that there are many possible routes and configurations of refineries (for example, cat cracking versus hydrocracking), all refineries by all routes are bound by this hydrogen balance issue. The exact configuration of a refinery can cause minor variations in energy/CO_2, but the simple difference in hydrogen content between crude coming in and products going out are by far, the controlling factor.

In a typical refinery, roughly half of the H_2 is produced as a by-product from the catalytic reformer (and in the few refineries that have them, from the olefins plant) (NETL 2008). Most allocation schemes allocate the energy and CO_2 from the "on purpose" H_2 plant properly, but they ignore the impact of the reformer H_2, and if applicable, from the H_2 produced at the olefins plant. Ignoring the reformer H_2 production means that the H_2 consuming units get a substantial part of their H_2 requirements as a CO_2-free stream, and also that the reformer is not credited for the large CO_2 avoidance associated with its H_2 production and the displaced H_2 from the "on purpose" H_2 plant.

Production of gaseous H_2 in "on purpose" H_2 plants can be typically characterized by a well to tank footprint of circa 108 gCO_2e/MJ (GREET 2008). By comparison, the gasoline footprint is around 90 gCO_2e/MJ in GREET. This highlights the importance of correctly accounting for CO_2 emissions in processes involving hydrogen production.

If one looks at what drives hydrogen content of crude, it is mostly the heaviness, i.e., how much boils above 1,000°F/540°C. There is a modest added effect for whether the crude is of naphthenic or paraffinic character, but heaviness is more important. One would expect that the heavier the crude, and thus the less hydrogen that the crude contains, the higher the energy requirement and CO_2 intensity of the refinery.

On the product side, gasoline, jet, and diesel have roughly equivalent hydrogen content: For the main transport fuels[1], the C/H ratio would range for gasoline (EN220) ~1.7–1.9, for diesel (EN590) ~1.7–1.9 and for jet A-1 (AFQRJOS[2]) ~1.7–1.9. The mass ratio (carbon to hydrogen) estimated for these fuels range between 6.3 and 6.9 m/m for all of them (see footnote 1). It might seem logical to think that gasoline should have more hydrogen than jet or diesel because it has a lower boiling temperature range, and hydrogen content is normally higher as boiling point gets lower. But actually, because quality issues force a bias toward aromatic species for gasoline to maintain its octane rating, while at the same time there is an opposite bias toward paraffinic content for jet and diesel to maintain their smoke point and cetane ratings things balance out in such a way that the main transportation fuels are similar in hydrogen content, and thus should be similar in their CO_2 emissions intensity.

LPG (generally C_3 and C_4 molecules) contains more hydrogen than gasoline, jet, and diesel, so should have higher CO_2 intensity. Some might think LPG should be low CO_2 intensity since much of it comes from simple fractionators. But LPG is not an "on-purpose" product, it is a byproduct. If more LPG were made by choosing catalysts that did more overcracking, the LPG would carry away more hydrogen in the product, requiring more refining and hydrogen manufacturing energy.

By contrast to high hydrogen LPG, residual fuel oil has very low hydrogen content. Resid can either be produced by the refinery as a product, or cracked in a resid cracking unit such as a coker. Coking is energy intensive, not only because of the coker itself, but also because the coker makes hydrogen deficient products which need extra hydrogen to be added in subsequent refining steps. Allowing the resid to go out as residual product rather than cracking it to lighter products saves large amounts of energy, thus making resid a very low energy product.

While not explicitly studied in the model runs described in this paper, other factors can influence refinery CO_2 emissions. One example has already been mentioned, namely, energy conservation which would lower CO_2 emissions. Others would include product specification changes such as lower sulfur or lower aromatics, which would raise CO_2 emissions. And finally, going to production ratios of products outside "normal ranges" could negate the conclusion that all of the light transportation fuels have "roughly equal" CO_2 emissions. If a refinery is forced to make more of a particular fuel than can be accommodated within "natural refinery flexibility" (such as very high diesel production, with very low gasoline production), CO_2 emissions would clearly increase. Variations in production ratios modeled in this paper were all within normal ranges of refinery flexibility, with an average swing between gasoline and diesel for high to low gasoline cases of around 4% on crude, and ranged between 2% and 6% depending on crude type and refinery configuration.

Subject to these caveats, we might expect that the refinery production of CO_2 (i.e., consumption of fuel, including the fuel needed to manufacture hydrogen) to produce gasoline, jet, and diesel should be roughly equal. Because refinery energy is mostly proportional to product versus feed hydrogen content, and the hydrogen content of gasoline, jet, and diesel products are similar. Using this same logic, LPG should be higher in CO_2 intensity and bunker-type residual fuel lower. CO_2 emission and energy consumption will be higher for heavier crudes than light, and slightly higher for naphthenic than for paraffinic crudes. Other factors should not influence refinery energy consumption as shown by the refinery model runs described in Section 3. Hydrogen content of the various feed and product streams is the main driver of refinery CO_2 intensity critically important in developing a proper allocation scheme.

4.2 Allocation approaches

Many allocation methods have concluded that refining to gasoline is much more energy intensive than distillate, which is inconsistent with the findings in the previous section, where varying gasoline/distillate ratio did not have much effect on CO_2 emissions. To understand why, a typical allocation approach was applied to the data from Section 3.

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[1] Shell Internal data

[2] Join Inspection Group, Products Specifications. Aviation Fuel Quality Requirements for Jointly Operated Systems (AFQRJOS). Issue 22–28 June 2007

The energy consumptions of the individual process units from the 24 runs in Section 3 were distributed into products according to process unit yields from those runs. For example, if a given unit consumed 10 units of energy, and its yields were 40% gasoline, 40% distillate 10% LPG, and 10% resid; its 10 units of energy would be allocated 4, 4, 1, 1 to those products. For the hydrogen plant, energy was distributed to the individual units according to the relative hydrogen consumption of that unit and from there by-product, as with the normal fuel. Using this approach, gasoline was approaching a factor of two times more energy intense than distillate. But this handles hydrogen incorrectly.

In the above scheme, the fuel and feed gas associated with the hydrogen plant is allocated to the hydrogen-consuming units on the basis of their relative hydrogen consumptions, and from there to products. However, only about half of the refinery's hydrogen comes from the hydrogen plant. The remaining half comes from the catalytic reformer, which is totally associated with gasoline production. Recall from Section 4.1 that gasoline is biased toward aromatics for quality purposes (i.e., octane rating), and the reformer is the process step that gives this bias. If the refinery makes less gasoline, it would have a smaller reformer, which would make less hydrogen, which would then require a larger hydrogen plant, which would consume more energy. So the reformer, from a refinery energy and CO_2 emissions standpoint, is an energy/CO_2 equalizing device, shifting energy/CO_2 from gasoline into distillates.

If the allocation scheme does not recognize this hydrogen-equalizing feature of catalytic reforming, it will conclude that gasoline has greater CO_2 and energy intensity than jet or diesel. But once the hydrogen production of the reformer is included in the allocation, the allocation will correctly show essentially equivalent energy intensity for gasoline, jet, and diesel. Note that this decision on how to allocate is not arbitrary. Without the reformer hydrogen correction, the allocation does not match actual refinery behavior, while with it, it does. So refinery reality, not arbitrary shifting, is being used to guide the allocation method.

There are various algebraic ways of including the reformer hydrogen production in the allocation scheme. The one chosen counts the energy equivalent of hydrogen as a credit/debit to each unit (credit to H_2 producing units, debit to consuming units), and does not count the hydrogen plant (because it is implicitly counted by debiting the consuming units for the energy equivalent of their hydrogen consumption). Using this technique, the consuming units pay the CO_2 penalty for all of their hydrogen, not just the fraction of hydrogen coming from the hydrogen plant. With this technique, the CO_2 intensity of gasoline versus distillate equals out, which agrees with the observed refinery behavior, which is that refinery energy consumption does not change as gasoline to distillate ratio changes. If gasoline was more energy intensive than distillate, that would not be true.

4.3 Allocation results

The behavior described in Section 4.2 is shown quantitatively in Figs. 2 and 3. Starting with Fig. 2, which has only the coker cases, the right hand side has the results from the simple allocation without hydrogen correction. It shows much greater CO_2 intensity for gasoline using that approach. The left side of the figure includes the hydrogen correction, and gasoline is similar to distillate in CO_2 intensity. There is a slope in both blocks, with heavier crudes showing more energy consumption. This is the same slope as was seen in the left two blocks of Fig. 1 (discussed in Section 3), and is caused by the fact that heavier crudes require more coking. Fig. 3 is similar to Fig. 2, except that it has the #6 oil cases rather than the coker cases. It shows most of the same trends, for the same reasons, as Fig. 2. The only differences are that there is essentially no bias for crude heaviness, and the overall levels are lower than in Fig. 2. These differences also link back to Fig. 1, where the #6 oil cases had similar CO_2 emissions regardless of crude heaviness, and had lower CO_2 emissions than the coker cases. The slight slope with regard to crude heaviness in Fig. 3 is caused by two things: (1) the highly paraffinic far right crude is slightly low, while the highly naphthenic far left crude is slightly high, and (2) there is an eye-catching slope in Fig. 3 with regard to LPG, but LPG is a small flow, explained by other factors (see next paragraph). So concentrating on the gasoline and distillate, Fig. 3 is essentially flat with regard to crude heaviness. But while CO_2 emissions are flat, there is an indirect, heavy crude CO_2 penalty in the Fig. 3 cases because with no coker, more carbon-rich resid product leaves the refinery as the crude gets heavier.

Looking at the corrected distributions, a few other observations can be made. First, resid product has very low CO_2 intensity as no energy has been spent cracking it or adding hydrogen to it. Second, LPG has very high CO_2 intensity. While a very small amount of LPG is contained in crude oil, and is thus produced with low CO_2 intensity through simple fractionation, most of it is produced by cracking in the high CO_2 intensity cracking units. Indeed, the LPG CO_2 intensity increases with heavier crude. As crude gets heavier, the cracking units get larger, so a larger proportion of LPG comes from cracking rather than simple fractionation. And if a refinery were forced to make even more LPG on purpose by over-cracking, the LPG energy intensity would go up even further. So LPG over and above the very small quantity contained in crude oil should not be regarded as a low energy intensity product.

Fig. 2 Comparison between allocation methods for coker cases

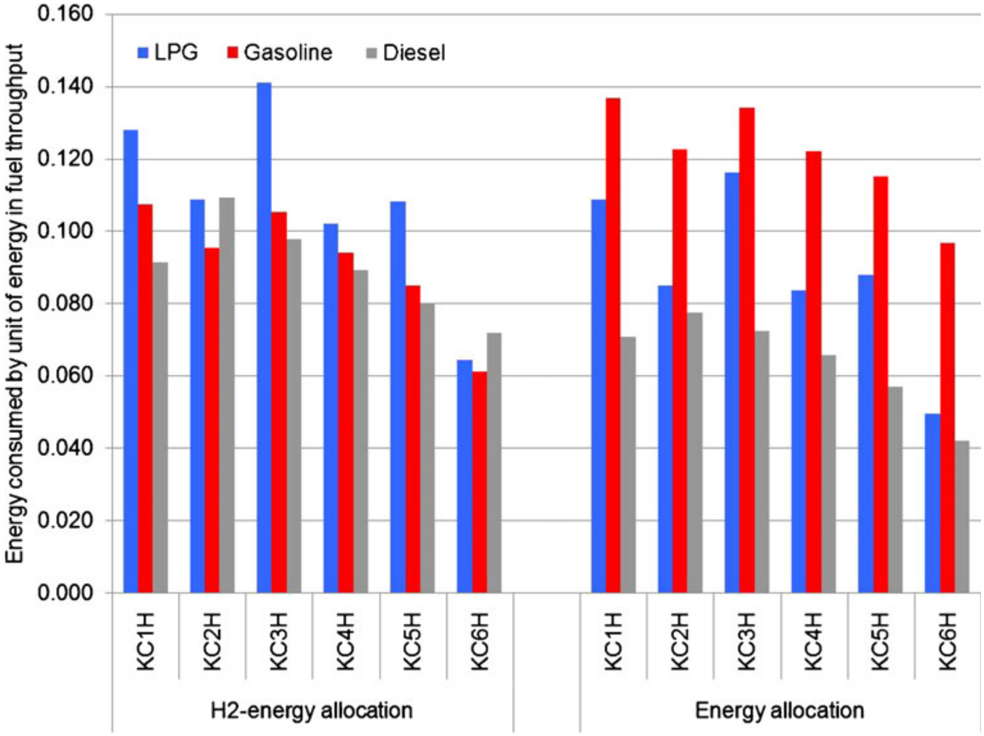
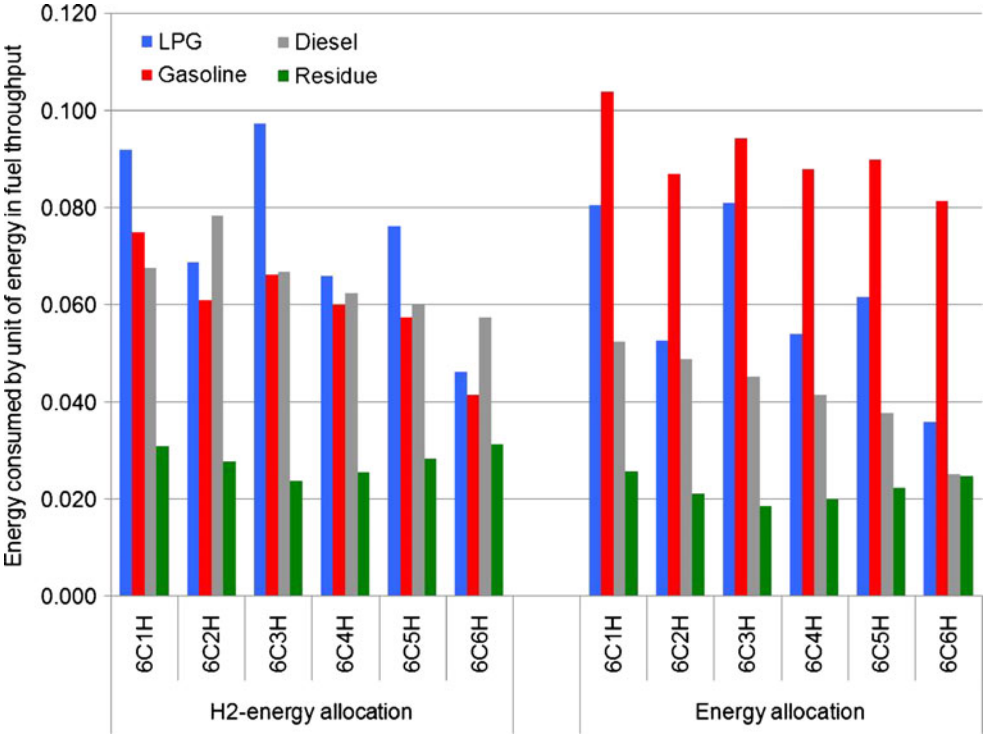


Fig. 3 Comparison between allocation methods for six oil cases



5 Conclusions

Total refinery CO_2 emissions are not strongly affected by ratio of gasoline to distillate product.

To agree with the above conclusion, an allocation scheme cannot conclude that gasoline is more CO_2 emissions intensive than distillate. To avoid that result, the allocation scheme must distribute energy into the various refinery products in a way that takes reformer hydrogen into account.

Refinery CO_2 emissions increase as it produces more transportation fuel and correspondingly less resid product. Operationally, this means that the refinery has a coker or other residue reduction unit, or said in another way, it is more complex.

In a complex refinery with a coker (or other residue reduction unit), making little or no residual fuel product, refinery CO_2 intensity is increased by running heavier crude. In a refinery that does not have a coker, and thus produces substantial quantities of residual fuel product, crude heaviness has little impact on total CO_2 emissions.

Refineries cannot vary LPG production by much, but if forced to make more LPG, total CO_2 emissions would increase. There is no way to make less LPG, it is minimized already.

While not studied explicitly in this paper, it should be self-evident that total refinery CO_2 emissions are also affected by degree of energy conservation excellence (i.e., capital equipment for energy conservation purposes) and by product specifications such as sulfur and aromatics.

6 Recommendations and perspectives

The conclusions on what impacts CO_2 intensity would seem to have obvious implications for regulatory methodologies. But there are a few added considerations that may not be immediately obvious from the conclusions themselves.

Allocation of refinery CO_2 emissions to individual products which does not stick to the technical reality is, by its very nature, rather arbitrary. This can be seen from the fact that using or not using the hydrogen corrections described in this paper has a dramatic impact on the allocation results. That arbitrariness should caution one against taking allocation results too literally. But if one insists on doing an allocation, at least it should be consistent with observed refinery behavior. The refinery behavior is that CO_2 emissions do not change very much with production ratio of gasoline to distillate. Thus, any allocation scheme which shows CO_2 intensities of gasoline and distillate are substantially different must be seen with caution, and special care should be put into understanding the handling of internal flows, the technical premises assumed, and how they align with the scope and goals of the LCA. Only with the understanding of the full context it is possible to conclude about the results and their implications.

The conclusion that CO_2 can be reduced by making more residual product in less complex refineries without cokers must be tempered with recognition that: (1) it would also lead to a carbon-rich stream (the resid) leaving the refinery; (2) refinery configurations and decision on make yield are driven many other external factors, for example, supply/demand balance of different products; and (3) well-to-wheels or life cycle effect should be considered in determining CO_2 reduction.

Similarly, the conclusion that CO_2 can be reduced by running lighter crude must be tempered with the realization that world crude demand is expected to continue to increase while world supply of light crude is limited [LBST 2007; EIA 2009]. Given that, it is likely that world demand for heavier crudes will continue to increase in the near future to meet consumer demand for transportation fuels.

Areas for further development This paper has not thoroughly handled jet versus diesel, grouping them instead as combined “distillate” fuel. If done simplistically, jet would show as being less energy intensive, because most jet comes via the crude unit and a low severity hydrotreater. But in similar fashion to LPG, if forced to make added jet, a refinery would need to include hydrocracked jet, and that is very energy intensive, often requiring a post-saturation step. Allocation methods could be developed to handle that complication, but that was thought to be beyond the scope of this paper. Instead, the simplifying step of combining jet and diesel into “distillate fuel” was adopted. However, this simplification does not undermine the conclusion that gasoline and diesel have similar overall refinery CO_2 emissions intensity. Simplistically, if jet is viewed as low CO_2 intensity, the algebra of the situation would force the intensity of diesel to be higher to balance. Thus, it does not offer a path back to the conclusion that gasoline is worse than diesel.

It is also acknowledged that precise refinery configuration or exact fuels specifications have not been studied in this study. Some runs were conducted to verify that those issues are far less important than the factors described herein, but it cannot be concluded that their effect is zero. In fact, the next phase of our work will be to study those issues more closely to determine which, if any, of such effects are non-trivial.

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Variability and Uncertainty in Life Cycle Assessment Models for Greenhouse Gas Emissions from Canadian Oil Sands Production

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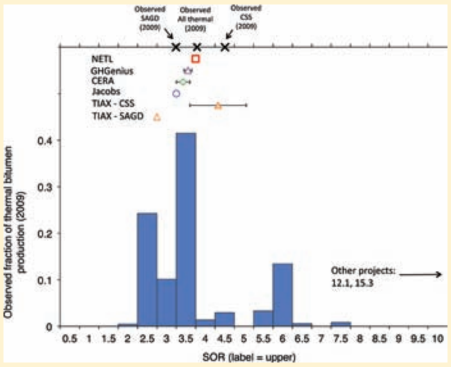
S Supporting Information

ABSTRACT: Because of interest in greenhouse gas (GHG) emissions from transportation fuels production, a number of recent life cycle assessment (LCA) studies have calculated GHG emissions from oil sands extraction, upgrading, and refining pathways. The results from these studies vary considerably. This paper reviews factors affecting energy consumption and GHG emissions from oil sands extraction. It then uses publicly available data to analyze the assumptions made in the LCA models to better understand the causes of variability in emissions estimates. It is found that the variation in oil sands GHG estimates is due to a variety of causes. In approximate order of importance, these are scope of modeling and choice of projects analyzed (e.g., specific projects vs industry averages); differences in assumed energy intensities of extraction and upgrading; differences in the fuel mix assumptions; treatment of secondary noncombustion emissions sources, such as venting, flaring, and fugitive emissions; and treatment of ecological emissions sources, such as land-use change-associated emissions. The GHGenius model is recommended as the LCA model that is most congruent with reported industry average data. GHGenius also has the most comprehensive system boundaries. Last, remaining uncertainties and future research needs are discussed.



■ INTRODUCTION

As conventional oil production becomes constrained, transportation fuels are being produced from low-quality hydrocarbon resources, such as bitumen deposits and other unconventional fossil resources. These include oil sands, enhanced oil recovery, coal-to-liquids and gas-to-liquids synthetic fuels, and oil shale.

Production of crude bitumen from the oil sands was almost 1.5 M bbl/d in 2009.[1,2] Production of liquid products from oil sands, including raw bitumen and synthetic crude oil (SCO), reached 1.35 M bbl/d in 2009. This represents an increase from ≈600 k bbl/d in 2000.[3] Current plans for expansion of production suggest over 7000 k bbl/d of capacity in all stages of operation, construction, and planning.[2]

In general, liquid fuels produced from unconventional resources have higher energy consumption per unit of fuel produced than those produced from conventional petroleum deposits. This is due to the higher energy intensity of primary resource extraction and the energy requirements of hydrocarbon processing and upgrading. Greenhouse gas (GHG) regulations such as the California Low Carbon Fuel Standard (LCFS) and European Union Fuel Quality Directive seek to properly account for the GHG intensities of these new fuel sources.

This paper examines models of upstream GHG emissions from Alberta oil sands production. The goal of this work is to understand the validity and comparability of previously published life cycle assessment models of GHGs from oil-sands-derived fuels, and to compile a range of emissions factors for oil-sands-derived fuel streams. Assumptions and data inputs to models are compared with observed data. Recommendations are then made for the use of these LCA results and for future research needs.

■ OVERVIEW OF OIL SANDS PRODUCTION METHODS

Oil sands are a mixture of sand and other mineral matter (80–85%), water (5–10%), and bitumen (10–18%).[4] Bitumen is a dense, viscous mixture of high-molecular-weight hydrocarbons. Bitumen is either diluted or upgraded to SCO before shipment to refineries for processing into liquid fuels.

Oil sands extraction. Bitumen is produced through surface mining or in situ production processes. Surface mining requires removal of overburden and mining of the bitumen/sand mixture (ore). The ore is transported to processing facilities where it is mixed with hot water, screened, and separated into bitumen and tailings.[4] A variety of in situ techniques exist, the most commonly applied being steam-assisted gravity drainage (SAGD) and cyclic steam stimulation (CSS).

Mining-Based Bitumen Production. Overburden removal is typically performed with a truck-and-shovel operation.[5] Bitumen ore is mined with diesel or electric hydraulic shovels. Large haul trucks move the ore to crushing and slurrying

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centers for hydrotransport to extraction centers (diesel-powered using fuel generated on site as SCO). Some processing equipment is powered with electricity coproduced on site from natural gas, upgrading process gas, or coke.[6] Published estimates of mining energy consumption vary by an order of magnitude (0.3–3.6 GJ/m^3 of SCO).[6−8] Given that the high end of this range (3.6 GJ/m^3 SCO) represents some 10% of the energy content of the SCO, this is most likely an overestimate of mining energy inputs.

At the extraction facilities, bitumen froth (60%+ bitumen, remainder water) is separated from sand, requiring warm water and consuming ≈40% of the energy used to produce a barrel of SCO.[5] Within integrated mining operations, upgrader by-products such as process gas and coke provide heat and power for the separation process.[6] After primary separation, bitumen froth is treated to remove water and solids, using naphtha or parrafinic solvents. This produces clean bitumen ready for upgrading to synthetic crude oil. Energy costs for separation of the bitumen are estimated at 0.9 GJ/m^3.[8,9]

In Situ Bitumen Production. Bitumen and heavy oil in the oil sands region are generally produced in situ using thermal methods such as CSS and SAGD, although smaller amounts of cold (primary) production of extra-heavy oil does occur in the oil sands region.[5,10] A significant reduction in hydrocarbon viscosity with modest increases in temperature allows bitumen to flow to the well for production. Thermal in situ production is generally more energy-intensive than mining-based production.

GHG emissions from in situ production result primarily from fuels combusted for steam generation. A key indicator is the steam oil ratio (SOR), often measured as cubic meters of cold-water equivalent (CWE) steam injected per cubic meter of oil produced. SORs for commercial thermal in situ recovery projects generally range from 2 to 5, with the production-weighted industry average being 3.6 in 2009.[10] This represents the volume-weighted average of projects listed in Energy Resources Conservation Board data sets as “commercial-CSS” and “commercial-SAGD”. Primary production of bitumen is not included because steam is not injected. SORs above 10 have been reported, but these represent transient effects at the outset of SAGD operations.[10] SORs have tended to improve over time with the maturation of SAGD technology.

The SOR is not the sole driver of in situ extraction emissions.[11] The amount of energy required to convert water to steam for injection depends on steam quality and pressure, the efficiency of steam generation, and heat recovery from produced fluids. Because of the requirement for 100% quality steam, the energy content of steam for SAGD projects is higher than that in heavy oil TEOR projects,[12] at ≈2.8 GJ/m^3.[11,13] Steam enthalpy varies little at relevant SAGD pressures, but the partitioning between sensible and latent heat changes across low- and high-pressure SAGD operating pressures.[11] To produce 100% quality steam, 80% quality steam is first produced in once-through steam generators (OTSGs), and condensate is returned to the boiler using vapor–liquid separators. This requires rejection of solute-laden water (“blowdown” water). Energy can be lost as a result of warm blowdown water. This energy requirement can be offset by the fact that produced fluids in a mature SAGD operation are hot, allowing heat recovery from the produced fluids stream. This produced fluid heat recovery has been suggested to equal some 10–30% of the heat content of the steam.[11] Literature estimates for steam energy requirements vary: Charpentier cites up to 2.8 GJ/m^3 of steam, whereas Butler cites ≈3.4 GJ/m^3 for 100% quality steam generation with heat recovery.[14,15] Electricity consumption for in situ production has been estimated as 190 MJ/m^3 bitumen (8.25 kWh/bbl bitumen) but will vary with SOR due to dependence on pumping and separation loads.[5]

Steam generation for in situ production is generally fueled with natural gas. An exception is the OPTI-Nexen Long Lake project, which consumes gasified bitumen residues,[16,17] increasing GHG emissions compared with natural-gas-fueled SAGD.[17,18]

Bitumen Upgrading. Because contaminants are concentrated in heavy hydrocarbon fractions, bitumen has a high sulfur and metals content. In addition, bitumen is carbon-rich, hydrogen-deficient, and contains a larger fraction of asphaltenes than conventional crude oil. Thus, bitumen requires more intensive upgrading and refining than conventional crude oil.

Raw bitumen will not flow through a pipeline at ambient temperatures so it is upgraded to SCO or diluted with a light hydrocarbon diluent (creating “dilbit”, or “synbit” if synthetic crude oil is used as the diluent) before transport. Diluent can be either returned to the processing site or included with bitumen to the refinery stream.

Greenhouse gas emissions from upgrading have three causes:

1 Combustion of fuels for process heat, including process gas, natural gas, and petroleum coke.
2 Hydrogen production using steam reformation of natural gas or, less commonly, from gasification of coke or bitumen residues.
3 Combustion for electricity generation (whether in cogeneration or off-site for from purchased electricity).

Upgrading bitumen to SCO is performed in two stages. Primary upgrading separates the bitumen into fractions and reduces the density of the resulting SCO. Secondary upgrading treats resulting SCO fractions to remove impurities such as sulfur, nitrogen, and metals.

Primary upgrading adjusts the H/C ratio by adding hydrogen or rejecting carbon from bitumen feedstock. The most common upgrading processes rely on fluid or delayed coking to reject carbon.[4,19,20] Coking generates upgraded oils as well as coke and process gas;[5] for example, Suncor’s delayed coking upgrading resulted in 85% SCO, 9% process gas, and 6% coke by heating value.[21] Natural gas or coproduced process gas is often used to drive coking, but in a fluid coker, a portion of the coke is combusted to fuel the coking process. In existing operations, coke disposition varies: in 2009, Suncor combusted 26% of produced coke and exported another 7% for offsite use, and the rest was stockpiled or landfilled. In contrast, the CNRL Horizon project stockpiled all produced coke.[21]

A competing primary upgrading method uses hydrogen addition for primary upgrading. The Shell Scotford upgrader[22] uses an ebullating-bed catalytic hydrotreating process. Treating bitumen with hydrogen addition results in larger volumes of SCO produced from a given bitumen stream and a high-quality product. It also requires larger volumes of H_2, with associated natural gas consumption and GHG emissions. The Scotford upgrader produced 82% of process outputs as SCO, 18% as process gas, and no coke (on an energy content basis).[21]

In secondary upgrading, the heavier fractions of primary upgrading processes (which contain the majority of the contaminants) are hydrotreated (i.e., treated through the addition of H_2 in the presence of heat, pressure, and a catalyst). Light refinery-ready SCO of 30–34°API, 0.1 wt %

sulfur, and 500 ppm nitrogen is a common product.[23] Heavy SCO products, such as Suncor Synthetic H, are also produced, but in smaller quantities (≈20°API and sulfur content of ≈3 wt %).[24] In chemical composition, dilbit looks similar to heavy synthetic blends.

Hydrogen consumption by hydrotreaters is often in excess of 3 times the stoichiometric requirement for heteroatom removal because of simultaneous hydrogenation of unsaturated hydrocarbons.[23] Hydrogen consumed in secondary upgrading is generally produced via steam methane reformation of natural gas, regardless of primary upgrading process.[6] Current exceptions include the OPTI-Nexen integrated SAGD to SCO project, which gasifies bitumen residues for H_2 production. Consumption of H_2 in upgrading processes ranges from 1.2 to 3.1 GJ/m^3 of bitumen upgraded.[25]

Nearly all of the bitumen produced from mining is upgraded, while most of the in situ-based production is shipped as a bitumen/diluent mixture to refineries.[5] There is no fundamental physical or chemical reason that in situ-produced bitumen cannot be upgraded.[17]

SCO and Bitumen Refining. Nonupgraded bitumen supplied to refineries requires intensive refining because of quality deficiencies. Refining of bitumen also produces a less desirable slate of outputs without extensive processing as a result of high asphaltenes content. Light SCO is a high-value product with low sulfur content compared with conventional oils of similar density, because light SCOs lack the typical "bottoms" of a conventional crude oil (i.e., residual products from distillation). This is because components that would form the bottom of the distillation output profile are destroyed during upgrading.

Refining energy consumption is well correlated with the specific gravity and contaminant loading (e.g., sulfur) of input crude oil.[26,27] This is due to need for additional coking or additional hydrogen consumption, both of which are energy-intensive.

Noncombustion Process Emissions. Other process emissions include emissions from venting, flaring, and fugitive emissions (hereafter, VFF emissions). Environment Canada reported emissions of ~3 g CO_2/MJ bitumen mined and in situ emissions of less than 1 g CO_2/MJ of bitumen produced.[28] Yeh et al.[29] found for mining operations that tailings ponds fugitive emissions had a wider range than fugitive emissions reported by Environment Canada, with a range of 0–8.7 g CO_2/MJ and a representative value of 2.3 g CO_2/MJ. It is not clear whether Environment Canada incorporates tailings pond emissions in these figures.

Land Use Change Associated Emissions. Land use change emissions are associated with biomass disturbance and oxidation due to land clearing, soil disturbance, and peat disturbance. These emissions are likely smaller than venting and fugitive emissions, with values ranging from 1.0 to 2.3 g CO_2/MJ of bitumen produced (representative value 1.4 g CO_2/MJ) for mining operations.[29] In a case that development is 100% on peatlands, land use emissions would increase by a factor of 3, suggesting that peat disturbance is a key driver of oil sands land use GHG emissions.[29] In situ operations have negligible land use emissions, ≈0.1 g CO_2 equiv/MJ of crude produced.

COMPARING PREVIOUS OIL SANDS LCA RESULTS

A number of LCAs of oil sands production have been performed, although none are yet comprehensive with detailed coverage of all oil sands production processes.[25,30,31] Over time, LCA studies have improved in quality and quantity of documentation, although gaps remain in the realm of publicly available models (see the Discussion and Recommendations section, below).

This paper reviews recent studies to determine the differences between study assumptions and to explore the uncertainty in resulting GHG emissions. The studies reviewed include

- **GREET**, the Greenhouse gases Regulated Emissions and Energy in Transportation model by Wang et al., Argonne National Laboratory;[32,33]
- **GHGenius**, the GHGenius model by O'Connor S&T[2] Consultants;.[34,35]
- **Jacobs**, a study by Keesom et al., Jacobs Consultancy;[25]
- **TIAX**, a study by Rosenfeld et al., TIAX LLC, and MathPro Inc.;[18]
- **NETL**, two studies by Gerdes and Skone, National Energy Technology Laboratory.[36,37]

A previous comprehensive comparison of oil sands GHG studies[6,19,38−41] was produced by Charpentier et al.[14] Other useful reviews are provided by Mui et al.[42,43] and by Hobbs et al., IHS-CERA Inc.[44] We will not attempt to recreate the analysis of these studies but in some cases use their results. One study reviewed but not included above is the Oil sands technology roadmap,[5] which is the source for GREET energy inputs to oil sands production.[45]

DIFFERENCES IN MODEL TREATMENT OF OIL SANDS PROCESSES

Determining the exact causes of differences between the results of reviewed models is impossible without access to original model calculations, but analysis of reported inputs and assumptions can give insight into reasons for divergence between estimates. These inputs can also suggest which model produces the most accurate estimates of project-specific or industry-wide emissions.

In all discussion below, energy content is reported on higher heating value basis (MJ or GJ HHV), and volumes are converted to cubic meters at standard conditions. Where required, volume- and mass-to-energy content conversions are made with fuel-specific compositions and relations between hydrocarbon density and chemical composition and heating values[46] (see the Supporting Information for calculation details).

System Boundaries and Study Scope. A main cause of variability between observed study results is the differences in broad methodological choices, such as study scope, system boundaries, and processes modeled (see Table 1).

A key difference between models is that some models assess emissions for an "average" oil-sands-derived fuel pathway, or generate industry averages (GREET, GHGenius, NETL), whereas others model emissions from specific oil sands projects (TIAX and Jacobs). This methodological difference overshadows many other sources of between-model variability.

The use of differing data sources of differing qualities is another major factor. As Charpentier et al. note, "the nature of the data used for the analysis varies significantly from theoretical literature values to project-specific material and energy balances".[14]

Another important difference is the study system boundary. Studies differ in the their treatment of indirect emissions (e.g.,

Table 1. Study Scope and System Boundaries by Reviewed Study

	scope of coverage	indirect emissions	embodied energy	venting, flaring, fugitives	land use
GREET	ind., pathway average	yes	no	yes	no
GHGenius	ind., pathway average	yes	no	yes	yes
Jacobs	process	NG + elec	no	no	no
TIAX	process	yes	no	yes	no
NETL	ind. average	yes	no	yes	no

emissions associated with producing natural gas consumed in upgrading operations), venting, flaring, and fugitive emissions as well as emissions from land use changes associated with oil sands mining. No study included emissions embodied in capital equipment (e.g., steel or cement upstream emissions).

Surface Mining. Emissions from mining are driven by the fuel consumed per unit of bitumen produced and the consumed fuel mix. In integrated operations, it is difficult to separate mining and upgrading inputs. Surface mining assumptions for each model are described below. The assumed fuel mixes and magnitudes of fuel consumption for mining and upgrading are shown by model in Figure 1. For comparison, industry reported fuel consumption (from regulatory data provided by the Alberta Energy Resources Conservation Board, or ERCB) are plotted in the right-most column.[47]

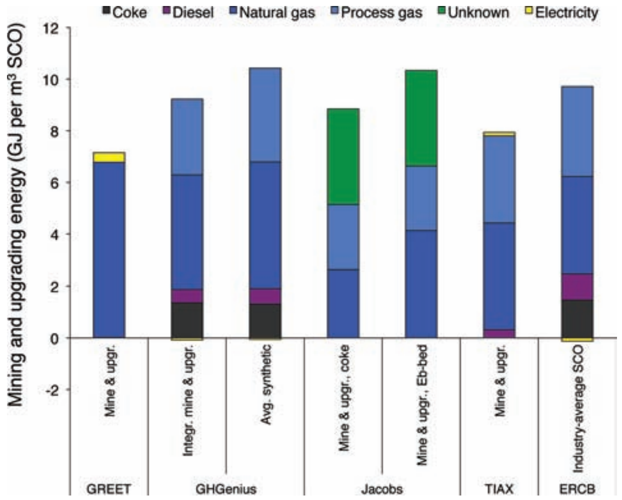

Figure 1. Fuel mix for mining and upgrading assumed by LCA models and industry average fuel mix (right). Fuel mix assumptions calculated from model inputs as described in text. Industry average fuel mix calculated from fuel consumption rates reported by ERCB for 2010 mining and upgrading operations.[47] See the Supporting Information for more detail on figure construction.

GREET. Estimates for diesel use are derived from Alberta Chamber of Resources data, which includes 340 MJ of electricity (94 kWh), 1573 MJ of natural gas, and 9 MJ diesel used/m^3 of bitumen mined.[45] This low diesel use is a possible difference between GREET results and those of other oil sands LCAs.

GREET assumes no coke consumption, which is at odds with empirical fuel mixes presented in Figure 1 and other reports.[6,19] In addition, although GREET figures are based on ACR fuel use data, GREET emissions are 15.9 g CO_2/MJ refined fuel delivered, whereas ACR emissions results are ≈19−22 g CO_2/MJ. (These figures are only approximate comparisons because ACR data are measured in kg CO_2/bbl of SCO produced, and conversion factors to energetic units are not provided in ACR.[5] SCO density and heating value were set to values for 31°API oil to allow comparison.) This is likely due to the omission of coke combustion in the GREET model. Charpentier previously noted these discrepancies, stating that "the energy balance in GREET appears to omit the diesel fuel used in mining and the coke used in upgrading".[14]

GHGenius. Data include emissions from off-site power and hydrogen production[35] as well as on-site cogeneration. Standalone mining operations consume 1.35 GJ diesel/m^3 of bitumen produced, 2.78 GJ natural gas, and coproduce 250 MJ of electricity for export. The weighted fuel mix in GHGenius for mining and upgrading to synthetic crude assumes 15% of energy content from coke,[34] closely in line with observed industry average mining fuel mix (see Figure 1).

Jacobs. The surface mining process model is not described in detail. It is stated that the energy for mining is "one-half of energy needed for SAGD at an SOR of 3." This represents an energy cost of ≈3.7 GJ/m^3 of bitumen of unknown fuel mix. Process model represents an integrated operation fueled with natural gas and using either ebullating-bed hydrogen-based upgrading or coking (no coke combustion). It is therefore similar to the CNRL Horizon oil sands project.

TIAX. The model represents the CNRL Horizon mining and upgrading project, which consumes natural gas and stockpiles coke generated during upgrading.[18] Total consumption for mining and upgrading is ≈8 GJ/m^3 of SCO.

NETL. The model uses emissions reported by Syncrude for integrated mining and upgrading operation,[37] as reported in Environment Canada facilities emission database.[48]

The TIAX and GREET models assume lower energy consumption than the industry average, whereas the Jacobs and GHGenius models are in line with observed consumption values. The GHGenius model has the most accurate fuel mix assumption for an industry average. Because Jacobs and TIAX model a specific project (e.g., CNRL Horizon) that is natural-gas-fueled, they do not replicate the industry average fuel mix.

This importance of fuel mix on emissions has implications for future emissions. Some argue that future projects will rely on coke as much as or more than current operations, because of decreasing availability of low-cost natural gas,[17,19] and others believe that unconventional gas resources will allow low gas prices in the long term.

One complication in comparing these studies is uneven modeling of cogeneration of electric power. This shortcoming is likely to be a secondary source of uncertainty. For example, Suncor exported some 4.1 PJ of electric power in 2009, compared with electricity consumption of 7.5 PJ and total energy consumption of 137.1 PJ,[21] suggesting that credits or debits due to cogeneration will likely be a secondary source of variation.

Upgrading Emissions. Upgrading emissions are driven by the energy consumed per unit of SCO produced plus the fuel mix used in upgrading. Study assumptions regarding upgrading include

GREET. Consumption of natural gas is ≈3.3 GJ/m^3 SCO produced.[45] No consumption of coke or process gas is recorded, which differs from reported fuel mixes by operators.[47]

Upgrading consumption values are low compared with other estimates (e.g., Jacobs).

GHGenius. Imputed upgrading consumption in integrated mining and upgrading is 5.1 GJ/m^3, whereas stand-alone upgrading is much more energy-intensive at ≈9.8 GJ/m^3 SCO.[35] Fuel mix is included in Figure 1.

Jacobs. Consumption is ≈5.7 GJ/m^3 SCO for coking, and 7.4 GJ/m^3 SCO for Eb-bed. Fuel mix includes both natural gas and process gas. The fuel mix is ≈50% each natural gas and process gas for the coking unit, 60% natural gas and 40% process gas in Eb-bed reactor,[25] with no consumption of coke.

TIAX. The study does not report upgrading consumption separately from mining or SAGD consumption. Integrated operations are modeled, and process flows are not delineated by mining and upgrading stages.[18]

NETL. A separate description of upgrading is not given in NETL studies.[36,37] Upgrading emissions are included in emissions from Syncrude integrating mining and upgrading operation, as described above.

Differences in emissions between Jacobs and GHGenius estimates are likely due to fuel mix differences, due to the similar energy consumption values. Given observed consumption of coke (see ERCB data in Figure 1), GHGenius estimates are more representative of industry-wide upgrading emissions. GHG-intensive upgrading using bitumen residues at OPTI-Nexen Long Lake project is neglected in all models except TIAX, but this is a relatively small operation, and therefore, this will not strongly affect model results in other models.

In Situ Production. Because of relatively homogeneous fuel mix consumed for in situ production, the primary determinants of emissions are the SOR and the energy consumed per unit of steam produced. In some studies, the product of these two terms—the energy consumed per volume of crude bitumen produced—is reported. Model assumptions include

GREET. Natural gas consumption is ~6.8 GJ/m^3 bitumen.[45] Because no SOR is reported, the energy consumed per cubic meter of steam cannot be calculated.

GHGenius. SORs of 3.2 and 3.4 assumed for SAGD and CSS, respectively.[14,49] Natural gas consumption is 9.6 and 10.2 GJ/m^3 of bitumen produced for CSS and SAGD, respectively.

Jacobs. Jacobs assumes SORs of 3.[25] Energy content of steam is 2.06 GJ/m^3 CWE steam, and efficiency is 85% (LHV basis), for total consumption of ≈8.1 GJ LHV/m^3 bitumen. Cogeneration of electric power provides an emissions offset in some cases.[25] Because SAGD net cogeneration exports are not reported in ERCB data sets, electricity exports cannot be verified using reported industry data.[22]

TIAX. Natural gas consumption rates are at the low end of the above cited range, 4.1 and 7.8 GJ/m^3 bitumen for Christina Lake (SAGD) and Cold Lake (CSS) respectively (without cogeneration).[18] The Christina Lake SAGD case has an SOR of 2.5 and a low implied energy consumption of 1.7 GJ/m^3 CWE of steam. These values are lower than the empirical values shown below, driving the low emissions from the TIAX natural gas case. Cases with cogeneration have somewhat higher effective steam energy requirements (see the Supporting Information). TIAX is the only report to consider integrated in situ production with bitumen residue or coke fueling. The TIAX case with asphaltenes residue gasification for steam generation (analogous to OPTI-Nexen Long Lake project) has a higher energy demand of 5.4 GJ/m^3 of steam generated, resulting in much higher emissions, as should be expected from the carbon intensity of asphaltene residue gasification.[18]

NETL. Emissions calculated for Imperial Oil Cold Lake project using CSS,[37] as reported in the Environment Canada facilities emission database.[48] In 2009, Cold Lake had an SOR of 3.5.[21]

The energy intensity of steam generation for the reviewed studies can be compared with calculated values from engineering fundamentals and values reported in the literature. These comparisons are shown in Figure 2. At top are fundamental computations of energy requirements, including the steam enthalpy at typical SAGD conditions (100% quality steam at 2000 kPa, or $h_g \approx 2.8$ GJ/m^3)[11] and the required energy consumption for steam generation, assuming no heat recovery from produced fluids. Also shown is a consumption band assuming 10−30% heat recovery from produced fluids. Next, estimates from the literature are presented, which are generally in line with fundamental values. Next, monthly energy intensities for 8 in situ projects are calculated from the reported literature. Last, assumptions for energy consumption in steam generation are shown for reviewed LCA models. A key result is that TIAX values are significantly lower than values from the literature. See the Supporting Information for figure construction details.

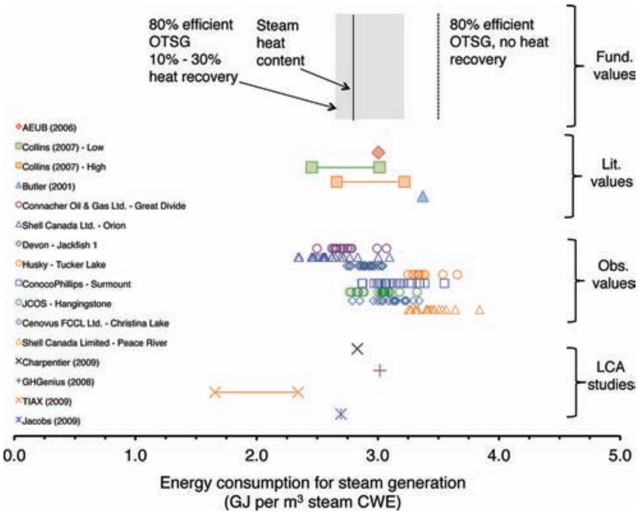

Figure 2. Assumed energy intensity of steam generation for studies and values from literature. Lines and shaded areas represent the energy content of the steam at typical SAGD conditions[11] (solid), the energy cost of obtaining this steam with an 80% efficient OTSG and complete heat recovery from blowdown water (dashed), and the energy cost with 80% efficient OTSG and heat recovery of 10−30% of the enthalpy of steam from warm produced fluids (shaded). Values are from the literature from various sources.[11,15,50]

In addition, the SORs assumed can be compared with SORs observed in practice, as in Figure 3. The SOR histogram shows SORs by fraction of industry output from reported data, as well as averages by process type (top axis). GHGenius and NETL report SORs in line with observed SORs, whereas the TIAX SAGD case is toward the low end of observed SORs.

Refining Emissions. Many LCA studies to date treat the refining of crude inputs (SCO and bitumen) in a simple fashion.[32,51] This is partly due to the absence of publicly available models of refinery operations and due to the fact that some models (such as GREET) have sought to produce a national average result, without modeling refining differences between individual crude oils.

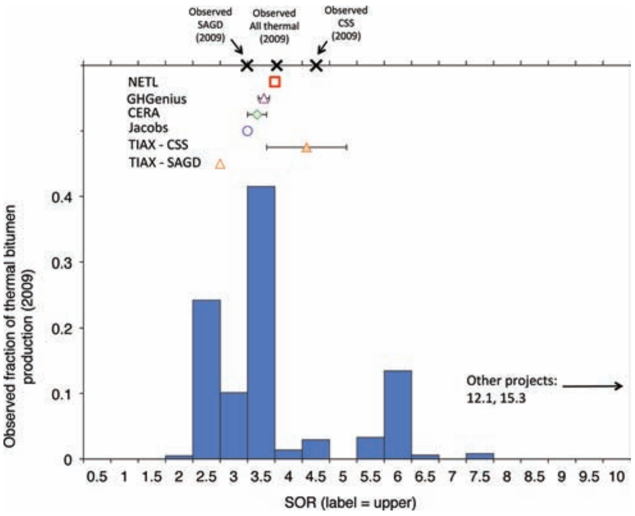

Figure 3. Assumed SORs for each model compared with observed SORs from ERCB data. Top marks represent production-weighted average for CSS and SAGD operations and 2009 full-year production volumes.

Refinery feedstock qualities differ by study, as shown in the Supporting Information. Some studies do not state explicitly the quality of refinery feedstock. SCO characteristics from studies align well with the reported characteristics of commercial SCO products. The resulting estimates of refining emissions as a function of crude specific gravity are plotted in Figure 4.

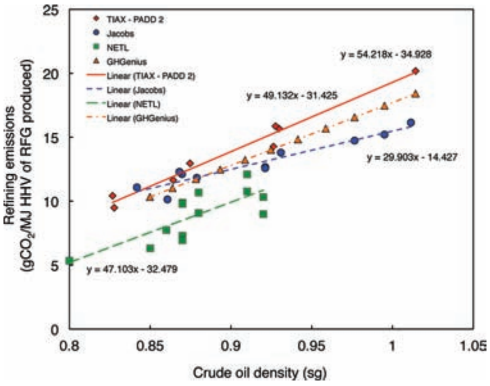

Figure 4. Refining emissions as a function of crude specific gravity for oil sands GHG emissions study. For TIAX, Jacobs, and NETL, the sulfur content varies with crude type. For GHGenius results, model version 3.20 was used with 2 wt % sulfur content for all crude oils.

GREET. The model calculates refinery emissions from processing oil-sands-derived streams as equivalent to processing conventional crude oil streams.[45,40] This assumption will not result in significant errors because GREET assumes bitumen is upgraded to SCO.[40]

GHGenius. The model relies (as of version 3.20) on a linear model of refinery emissions as a function of API gravity and sulfur, derived from Karras.[26] The relationship between sulfur and emissions is from Karras, and the slope of energy consumed as a function of density is set to one-half the Karras value.[34]

Jacobs. Detailed calculation of refinery inputs and outputs with refining simulation software. Results from the commercial refinery process model are presented in detail, with process throughputs and products breakdown provided for SCO, bitumen, and dilbit.[25] Detailed refining utilities consumption by subprocess is presented for Arab Medium crude, but not for oil sands pathways.[25]

TIAX. The model performs a detailed calculation of refinery inputs and outputs, using industry refinery modeling expertise, with extensive documentation. Model results include differential refining emissions based on the quality of the feedstock.[18]

NETL. The approach used by Gerdes et al.[36] is outlined in detail in Skone et al.[37] A novel approach is developed using US nationwide statistical data on refinery configurations, crude throughputs, crude qualities, and utilization factors for different crude processing stages (e.g., distillation utilized capacity vs fluid catalytic cracking utilized capacity). This approach is similar to that taken by Karras.[26] Heuristic models for the effect of crude density and sulfur content on refining intensity are developed.[36]

The Jacobs and TIAX models represent the most thorough efforts to date to model refinery emissions for refining oil-sands-derived fuels. The NETL model represents the most thorough treatment of the problem using public data. Given the relative similarity of refinery emissions model results, it is not clear that enough empirical data exists about refinery emissions to assess the relative merits of the different models. One concern in refinery modeling is that the different quality of SCO as compared with conventional oil will change refinery output slates, possibly indirectly affecting emissions in other sectors (see Discussion and Recommendations, below). In addition, a number of parameters not included in current simple refining models could be causing discrepancies between different model results (for example, Jacobs notes sensitivity to refinery configuration, which is not included in simpler models).

Other Process Emissions. Emissions from venting, fugitive emissions, and flaring (VFF) are unevenly addressed in the above studies. GREET does not include VFF emissions from bitumen extraction or upgrading.[40] GHGenius does include venting and flaring emissions.[34] Jacobs does not explicitly include VFF emissions from oil sands production.[25] TIAX does include VFF emissions, of 0.5 to 3.3 g CO_2 equiv/MJ[18] from regulatory documents related to the Horizon oil sands mine. NETL does include venting and flaring,[36] but does not describe method for estimating bitumen VFF emissions.

Land use emissions are considered only in the GHGenius model, which calculates soil and biomass disturbance per hectare and apportions this according to the type of operation (e.g., 100% disturbance on mined lands, no disturbance for SAGD).[35]

Resulting GHG Emissions Estimates. The resulting upstream GHG emissions estimates by study are shown in Figure 5. For simplicity, vehicular emissions (tank-to-wheel) emissions are given a nominal value of 70 g CO_2/MJ in all cases (TTW results are largely consistent across models and are not a focus of this study). A detailed breakdown of emissions for each data point is given in the Supporting Information.

General trends emerge among pathways as a result of the underlying fundamentals of process operation. In situ and upgrading projects have higher emissions, as should be expected from projects that combine energy-intensive extraction methods with energy-intensive upgrading.

Variability between estimates from a given study arise from varying process assumptions. For example, the four TIAX results for in situ-to-bitumen pathways differ in their

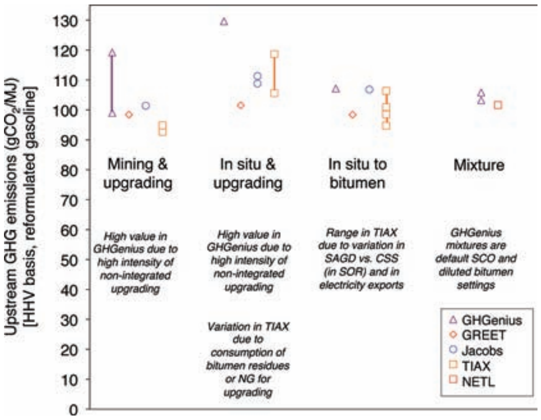

Figure 5. Full-fuel-cycle GHG emissions estimates for reformulated gasoline pathways by study. Nominal value of 70 g CO_2/MJ for combustion emissions is applied evenly across all studies. Details on construction of th estimates are given in the Supporting Information.

assumptions about the method of extraction used (i.e., SAGD vs CSS) and in whether they export cogenerated electric power. Clearly, emissions will vary between among implementations of similar pathways.

In general, GREET and TIAX model results are at the lower end of the emissions range. This should be expected from their assumptions about the energy intensity of extraction, as shown above for mining and in situ production.

In addition, in general, the GHGenius model tends to have somewhat higher emissions than other studies. A driver of these higher emissions is due to more careful accounting of energy consumption in GHGenius and due to industry-average fuel mixes that contain coke combustion. Some additional research is needed with respect to GHGenius stand-alone upgrading emissions, which are assigned a high emissions intensity. This does not strongly affect the overall results from GHGenius (as plotted in Figure 5 in the "mixture" column as default SCO and default bitumen pathways) because stand-alone upgrading is not a major pathway in current operations. In general, given the fidelity of GHGenius in replicating energy inputs to mining and in situ processes, GHGenius emissions estimates should not be considered overly pessimistic.

■ DISCUSSION AND RECOMMENDATIONS

Recommended Use of Model Results. The GHGenius model is recommended for use in generating industry-average GHG emissions values, such as those that might be required to assign default values in regulation. GHGenius contains the most accurate representation of observed energy consumption values for the industry as a whole, as seen in Figure 1 for surface mining and upgrading operations, in Figure 2 for steam energy content, and in Figure 3 for steam/oil ratios. It also includes emissions sources such as VFF and land use emissions that are not covered consistently by other models. In addition, its transparent and extensive documentation is a useful contribution to the literature and allows for fact checking of inputs.

Although the GREET model is publicly available and treats industry average pathways, its use for constructing industry-average emissions is not recommended because of less accurate energy intensity and fuel mix assumptions compared with GHGenius.

The Jacobs and TIAX models represent more detailed LCA studies of project-specific emissions. They provided important advances in refinery models compared with earlier studies. These estimates are useful for understanding specific pathways, but should not be considered representative of industry-wide emissions averages because of their focus on specific projects that may not be representative of general industry conditions.

Comparability of Studies. Figure 5 shows the considerable variation among model results for different processes and even significant variation within similar pathways. The key factor affecting the comparability of studies is whether study results are process-specific or pathway or industry-average emissions estimates. Process-specific emissions estimates and industry-average emissions estimates are useful in different contexts.

For regulatory purposes for determining the potential overall scale of differences in emissions among broad fuel types (e.g., conventional oil and oil sands), industry-wide production-weighted average emissions are more useful than process-specific assessments. For evaluating the GHG intensity of a given process or a given import stream, process-specific emissions estimates are required.

Other factors affecting the comparability of models include the study system boundaries. In the studied LCA models, study system boundaries are broadly commensurate (e.g., all are well-to-wheel LCA analyses), although smaller system boundary considerations were noted above, such as the inclusion or exclusion of land use emissions.

Uncertainties and Need for Future Work. A number of uncertainties remain in the area of oil sands GHG emissions. Treatment of cogenerated electric power varies among models. Given the CO_2 intensity of the Alberta grid, coproduction credits from cogenerated power could be provide emissions offsets. Important future research needs for electricity credits include variation with time, place, and characteristics of Alberta grid in relation to interconnected grids.

Treatment of refining is a difficulty in public-domain studies such as GREET and GHGenius because of a lack of access to industry-vetted refinery models. The Jacobs and TIAX refining models represent the most detailed work to date on refining emissions (although their models are not publicly available). The previous lack of data on refining emissions has been remedied somewhat recently, with increasing public access to correlations between emissions and crude density and sulfur content,[26] but additional work is needed. Importantly, refinery emissions vary with refinery configuration, the type of oil sands product refined (i.e., SCO, dilbit or synbit), and the refinery output slate.

Numerous coproduction issues arise that are not incorporated consistently in current studies. For example, the treatment of coproduced coke is a complex issue. This is noted in the Jacobs study but not treated elsewhere. At remote Alberta upgrading facilities, coproduced coke is generally stockpiled or burned on site to fuel operations. If bitumen is shipped to refineries as dilbit, this will result in coke generation near existing fuels markets, which could result in more coke being consumed, offsetting some coal consumption. Calculating the magnitude of credit or debit associated with such coproduction and displacement is nontrivial and requires understanding of the markets for solid fuels. Similar concerns arise with the treatment of diluent in dilbit pathways.

The interaction of oil sands products with existing fuel production systems and fuel demands is still poorly understood. For example, refinery outputs from refining a light SCO product will differ from outputs from a crude oil input of similar specific gravity and sulfur content (more middle distillate and less residual fuel from SCO). This could have ripple effects on other fuels markets and alter the energy requirements of producing a given refinery mix (e.g., EU refineries might not face as large an energy penalty associated with producing diesel-heavy refinery product slate).

The interaction of markets in LCA (as addressed in "consequential" LCA) is not studied in detail in any of the above models. Given a regulation that reduced the demand for oil sands products in North America (such as an expansion of the California LCFS to the national scale), there could be shifts in shipment of liquid fuels in the global fuels market (also known as crude shuffling). This shift of fuels could offset some of the desired reduction in emissions. The calculation of such impacts would require a combination of fuel market models with detailed LCA models. This is a difficult problem and likely subject to significant uncertainty.

Future work in oil sands GHG emissions should move toward modeling the emissions of specific process configurations. For example, models should be used to model emissions by project and compare those modeled emissions to reported emissions estimates. More vigorous calibration with available data (such as ERCB reported data sets) will help verify model accuracy. Much of the variability seen in the results above is driven by fundamental differences between different process operations (e.g., fuel mix or steam generation efficiency variation between project). Without more transparency and clarity about which processes are being modeled (and how representative they are of industry-wide operations), additional confusion will be introduced into assessing the environmental impacts of oil sands production.

■ ASSOCIATED CONTENT

Ⓢ Supporting Information

Additional results, including tabular results for important results figures. This material is available free of charge via the Internet at http://pubs.acs.org.

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CONTENTS

ACRONYMS

AGO — Atmospheric Gas Oil

ANS — Alaska North Slope

API — measure (in degrees) of an oil’s gravity or weight

AR — Atmospheric Residue

bbl — Barrel

C-B — Coke Burned

CNR — Catalytic Naphtha Reformer

CO_2 — Carbon Dioxide

CO_2 eq. — Carbon Dioxide Equivalent (including all GHGs)

dilbit — Diluted Bitumen

FCC — Fluid Catalytic Cracking

GHGs — Greenhouse Gases

GIS — Geographic Information System

GO — Gas Oil

GO-HC — Gas Oil-Hydrocracker

GOR — Gas-to-Oil Ratio

HC — Hydrocracker

HVGO — Heavy Vacuum Gas Oil

kg — Kilogram

km — Kilometer

LCA — Life-Cycle Assessment

LSR — Light Straight Run

LTO — Light Tight Oil

LVGO — Light Vacuum Gas Oil

mbd — Million barrels per day, also termed “mbpd”

MJ — Megajoule (unit of energy)

OCI — Oil-Climate Index

OPEC — Organization of the Petroleum Exporting Countries

OPEM — Oil Products Emissions Module

OPGEE — Oil Production Greenhouse Gas Emissions Estimator

PRELIM — Petroleum Refinery Life-cycle Inventory Model

RFG — Refinery Fuel Gas

SCO — Synthetic Crude Oil

SMR — Steam Methane Reformer

SOR — Steam-to-Oil Ratio

tonne — Metric Ton

VR — Vacuum Residue

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Naturally, this report's contents remain entirely the responsibility of its authors.

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SUMMARY

OIL IS CHANGING. Conventional oil resources are dwindling as tight oil, oil sands, heavy oils, and others emerge. Technological advances mean that these unconventional hydrocarbon deposits in once-unreachable areas are now viable resources. Meanwhile, scientific evidence is mounting that climate change is occurring, but the climate impacts of these new oils are not well understood. The Carnegie Endowment's Energy and Climate Program, Stanford University, and the University of Calgary have developed a first-of-its-kind Oil-Climate Index (OCI) to compare these resources.

ALL OILS ARE NOT CREATED EQUAL

- Thirty global test oils were modeled during Phase 1 of the index.
- Greenhouse gas (GHG) emissions were analyzed throughout the entire oil supply chain—oil extraction, crude transport, refining, marketing, and product combustion and end use.
- There is an over 80 percent difference in total GHG emissions per barrel of the lowest GHG-emitting Phase 1 oil and the highest.

- Climate impacts vary whether crudes are measured based on their volumes, their products' monetary values, or their products' energy delivered.
- The GHG emission spread between oils is expected to grow as new, unconventional oils are identified.
- Each barrel of oil produces a variety of marketable products. Some are used to fuel cars and trucks, while others—such as petcoke and fuel oils—flow to different sectors. Developing policies that account for leakage of GHG emissions into all sectors is critical.
- The variations in oils' climate impacts are not sufficiently factored into policymaking or priced into the market value of crudes or their petroleum products.
- As competition among new oils for market share mounts, it will be increasingly important to consider climate risks in prioritizing their development.

NEXT STEPS FOR THE OCI

- In order to guide energy and climate decisionmaking, investors need to make realistic asset valuations and industry must make sound infrastructure plans. Policymakers need to condition permits, set standards, and price carbon. And the public needs information and incentives to make wise energy choices.
- The OCI can shape how these stakeholders address the climate impacts of oil, and the use of the index can foster critical public-private discussions about these issues.
- The most GHG-intensive oils currently identified—gassy oils, heavy oils, watery and depleted oils, and extreme oils—merit special attention from investors, oil-field operators, and policymakers.
- To increase transparency on a greater volume and variety of global oil resources, it will be necessary to expand the OCI. This will require more high-quality, consistent, open-source oil data. This information will facilitate the restructuring of oil development in line with climate realities.

INTRODUCTION

THE CHARACTER OF oil is changing. Consumers may not notice the transformation—prices have fluctuated, but little else appears to have changed at the gas pump. Behind the scenes, though, the definition of oil is shifting in substantial ways. There is oil trapped tightly in shale rock, and oil pooled many miles below the oceans. Oil can be found in boreal forests, Arctic permafrost, and isolated geologic formations. Some oils are as thick as molasses or as gummy as tar, while others are solid or contain vastly more water or gas than normal.

As oil is changing, so, too, is the global climate.

Oil resources were once fairly homogeneous, produced using conventional means and refined into a limited number of end products by relatively simple methods. This is no longer the case. Advancements in technology mean that a wider array of hydrocarbon deposits in once-unreachable areas are now viable, extractable resources. And the techniques to turn these unconventional oils into petroleum products are becoming increasingly complex.

As oil is changing, so, too, is the global climate. The year 2014 ranked as the earth's warmest since 1880. Fossil fuels—oil along with coal and methane gas—are the major culprits.

The only way to determine the climate impacts of these previously untapped resources—and to compare how they stack up against one another—is to assess their greenhouse gas (GHG) emissions at each stage in the oil supply chain: exploration, extraction, processing, refining, transport, and end use. The more energy it takes to carry out these processes, the greater the impact on the climate. And in the extreme case of some of these oils, it may take nearly as much energy to produce, refine, and transport them as they provide to consumers. Moreover, each oil yields a different slate of petroleum products with different combustion characteristics and climate footprints.

The Oil-Climate Index (OCI) is a metric that takes into account the total life-cycle GHG emissions of individual oils—from upstream extraction to midstream refining to downstream end use. It offers a powerful, yet user-friendly, tool that allows investors, policymakers, industry, the public, and other stakeholders to compare crudes and assess their climate consequences both before development decisions are made as well as once operations are in progress. The Oil-Climate Index will also inform oil and climate policy making.

The index highlights two central facts: The fate of the entire oil barrel is critical to understanding and designing policies that reduce a crude oil's climate impacts. And oils' different climate impacts are not currently identified or priced into the market value of competing crudes or their petroleum products. As such, different oils may in fact entail very different carbon risks for resource owners or developers.

Different oils may entail very different carbon risks for resource owners or developers.

Analysis of the first 30 test oils to be modeled with the index reveals that emission differences between oils are far greater than currently acknowledged. Wide emission ranges exist whether values are calculated per barrel of crude, per megajoule of products, or per dollar value of products, and it is expected that these emission ranges could grow as new, unconventional oils are identified.

There are several critical variables that lead to these variations in oils' life-cycle climate emissions. They include how gas trapped with the oil is handled by producers, whether significant steam is required for oil production, if a lot of water is present as the oil reservoir depletes, how heavy (viscous) or deep the oil is, what type of refinery is used, and whether bottom-of-the-barrel products like petroleum coke (known as petcoke) are combusted. Given these factors, the most climate-intensive oils currently identified—gassy oils, heavy oils, watery and depleted oils, and extreme oils—require special attention from investors, operators, and policymakers.

Expanding the index to include more global oils is necessary in order to compare greater volumes of crudes. This requires more transparent, high-quality, consistent, accessible, open-source data. As competition mounts between new oils, information about emerging resources is needed to increase market efficiency, expand choices, leverage opportunities, and address climate challenges.

OIL 2.0

CONCERNS ABOUT OIL scarcity beset the world for nearly half a century, but that may no longer be the overriding worry. Larger questions loom about the changing nature of oil resources, their unknown characteristics, their climate and other environmental impacts, and policies to safely guide their development and use.

Indeed, there are thousands of oils available globally for production and use. The earth is stocked with a surfeit of hydrocarbons. As of 2013, there are an estimated 24 trillion barrels of oil in place, of which 6 trillion barrels are deemed technologically recoverable.

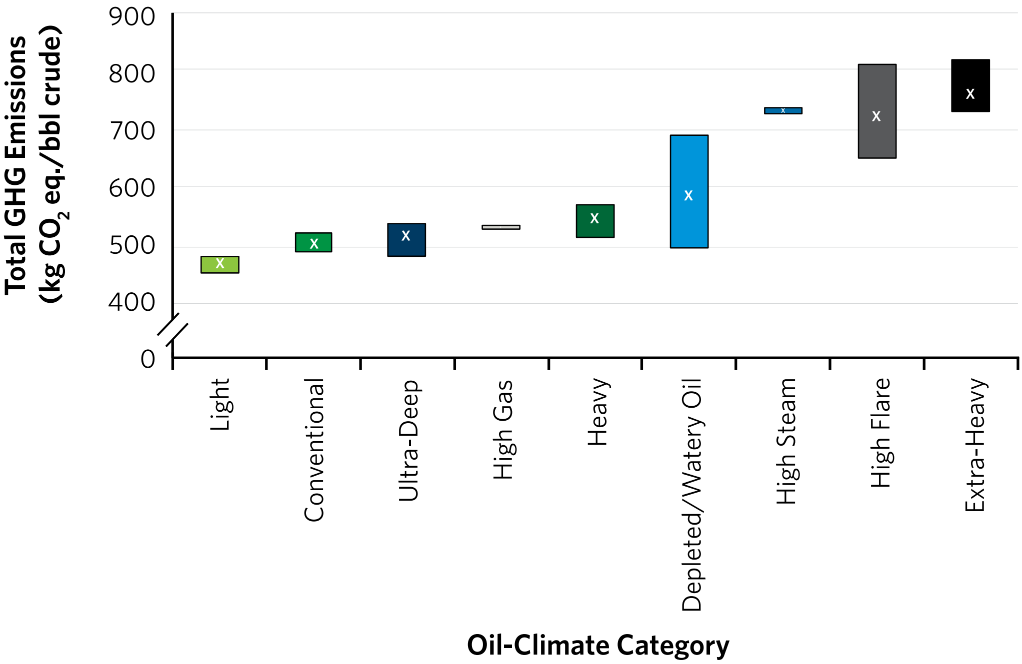
Advancements in technology that have unlocked unconventional hydrocarbon deposits in once-unreachable areas are costly and risky in both private and social terms.

These resources take different forms—from rocky kerogen to sludgy tar to volatile gassy liquids. They exist under vastly different conditions: deep and shallow; onshore and offshore; pooled and dispersed; and in deserts, permafrost, rainforests, and grasslands. An evolving array of techniques must be employed to transform them into a myriad of petroleum products, some more valuable than others, which flow in all directions to every economic sector and most household products.

Advancements in technology that have unlocked unconventional hydrocarbon deposits in once-unreachable areas are costly and risky in both private and social terms. Many of these advancements result in larger GHG emissions than traditional extraction methods, and some oils have more than 80 percent higher emissions per barrel than others (see figure 1).

FIGURE 1

GHG Emission Ranges for 30 Phase 1 OCI Test Oils, by Category



Source: Authors' calculations (calculations will be made available online at CarnegieEndowment.org)

Notes: "X" represents average GHG emissions for OCI test oils in each oil category. Extra-heavy oils include oil sands.

Consider a few examples. For California's Midway Sunset oil field, a sizable portion of the oil's own energy content is used before any of the petroleum products the field ultimately provides reach consumers. This century-old oil field requires large volumes of steam to be injected into the reservoir to loosen the oil and allow it to flow. Generating this steam requires up to one-third of the energy content of the oil itself, in the form of natural gas. The water content of this oil is high and therefore takes extra energy to lift. Much of its oil is very heavy and requires energy-intensive, complex refining techniques. The combination of energy used in extraction and refining means almost half of Midway Sunset's total greenhouse gas emissions are released before the resource even gets to market.

Other oils, such as Norway Ekofisk, fare much better in these regards. This light oil is more easily produced. Extraction operations are tightly regulated by the Norwegian government; as such, the gas produced with the oil is gathered and sold instead of burned (or flared) on-site and wasted. Ekofisk oil is processed by the simplest hydroskimming refinery, and less than 10 percent of its greenhouse gases are emitted before it gets to market.

Oil markets, meanwhile, are durable given the lack of ready substitutes. Oil consumption has marched steadily upward, from 77 million barrels per day (mbd) in 2000 to 92 mbd in 2014, despite a major global economic downturn. Oil dominates the transportation sector, providing 93 percent of motorized transportation energy. Overall, the oil sector is responsible for a reported 35 percent of global GHG emissions.

Parsing oils by their climate impacts allows multiple stakeholders, each with their own objectives, to consider climate risks in prioritizing the development of future oils and the adoption of greater policy oversight of today's oils. While objectives of stakeholders may vary (for example, environmental nongovernmental organizations may have different perspectives than investors), all actors would be better served by accurate, transparent measures of climate risk associated with different oils.

All actors would be better served by accurate, transparent measures of climate risk associated with different oils.

THE MOST CHALLENGING OILS

EVEN WITH THE decline in oil prices that began in August 2014, there remains fierce competition between diverse global oils. A few of them are more challenging in terms of climate change than others.

- Gassy oils: Oil fields typically have some natural gas (or methane) and other lighter gases (ethane and others) associated with them. The more gas that is present, the more challenging and costly it is to safely manage these commodities. When the gas associated with certain gassy oils is not handled properly, usually due to lack of appropriate equipment, the gas is burned or released as a waste byproduct. Both flaring and venting operations are damaging to the climate as they release carbon dioxide, methane, and other GHG emissions. Oils that resort to these practices can result in at least 75 percent larger GHG footprints than comparable light oils that do not flare. Flaring policies vary. For example, it has been illegal to flare associated gas in Norway since the 1970s, making these oils some of the lowest emitting oils produced today.
- Heavy oils: The heavier the oil, the more heat, steam, and hydrogen required to extract, transport, and transform it into high-value petroleum products like gasoline and diesel. These high-carbon oils also yield higher shares of bottom-of-the-barrel products like petcoke that are often priced to sell. The heaviest oils have total GHG footprints that can be nearly twice as large as lighter oils.

- Watery and depleted oils: Depleted oil fields tend to produce significant quantities of water along with the oil. It takes a lot of energy to bring this water to the surface, process it, and reinject or dispose of it. If an oil field has a water-oil ratio of ten to one, that adds nearly 2 tons of water for every barrel of oil produced. Certain depleted oils in California's San Joaquin Valley, for example, produced 25 or 50 barrels of water per barrel of oil. Oils with high water-oil ratios can have total GHG footprints that are more than 60 percent higher than oils that are not so encumbered.

- Extreme oils: Some oils are difficult to access. For example, some oils are buried deeply below the surface, like the Chayvo oil field in Russia's Sakhalin shelf, which is reached by an incredible set of highly deviated wells that are about 7 miles long. How much energy it takes to recover such resources is highly uncertain. Still other oils are located in areas that sequester greenhouse gases like permafrost, boreal peat bogs, and rainforests. Removing these oils disrupts lands that store significant amounts of carbon, releasing substantial volumes of climate-forcing gases. GHG footprints may be significantly larger for oils that are difficult to access or located in climate-sensitive environments, and this merits further investigation.

There is far too little information about the new generation of oil resources.

Whether global oil production returns to record levels, wanes, or fluctuates in the future, there is little doubt that oils will be increasingly unconventional. And there is little doubt that oil extraction, refining, and consumption should be better understood. There is far too little information about the new generation of oil resources.

CREATING AN OIL-CLIMATE INDEX

AS THE CHANGING climate results in higher social costs, the environmental limitations on oil production and consumption will have more significant effects than the industry has heretofore acknowledged.[1] Recent research has shown that to keep the earth from warming more than 2 degrees Celsius from preindustrial times—the limit set in the 2009 Copenhagen Accord as the threshold for “dangerous” human interference in the climate system—at least one-third of the world’s oil reserves should not be burned or the carbon from refined oil products’ combustion should be safely stored.[2] Investors and companies facing such constraints will need data on the total life-cycle emissions from the exploration, extraction, transportation, refining, and combustion of oil resources, data that do not now exist, at least not in a consistent, transparent, and peer-reviewed way.

The Oil-Climate Index is designed to fill that void by analyzing total GHG emissions (including all co-products) for given crudes using three different functional units, or different metrics, for comparison. The first version of the index includes: emissions per barrel of crude produced, emissions per energy content of all final petroleum products, and emissions per dollar value of all petroleum products sold.

The Oil-Climate Index uses the following open-source tools to evaluate actual emissions associated with an individual oil’s supply chain:

- **OPGEE** (Oil Production Greenhouse Gas Emissions Estimator), developed by Adam Brandt at Stanford University,[3] evaluates upstream oil emissions from extraction to transport to the refinery inlet.

- **PRELIM** (Petroleum Refinery Life-Cycle Inventory Model), developed by Joule Bergerson at the University of Calgary,[4] evaluates refining emissions and petroleum product yields.

- **OPEM** (Oil Products Emissions Module), developed by Deborah Gordon and Eugene Tan at the Carnegie Endowment for International Peace's Energy and Climate Program and Jonathan Koomey at Stanford University's Steyer-Taylor Center for Energy Policy and Finance, calculates the emissions that result from the transport and end use of all oil products yielded by a given crude. An overriding goal of the module is to include and thereby avoid carbon leakage from petroleum co-products.

While oil type, production specifications, and geography were initial factors in selecting oils to model in Phase 1 of the Oil-Climate Index, data availability turned out to be the overriding factor. The oils modeled in the first phase are found around the world (see table 1). Oils were analyzed across the entire value chain—the series of transformations and movements from an oil's origin to the consumption of the slate of petroleum products it yields.

TABLE 1

Locations of 30 Phase 1 OCI Test Oils

United States	Canada	Sub-Saharan Africa	Europe	Eurasia	Middle East & North Africa	Latin America & Caribbean	Asia-Pacific
U.S. California Midway Sunset	Canada Midale—Saskatchewan	Nigeria Obagi	UK Brent	Russia Chayvo	Iraq Zubair	Brazil Lula	China Bozhong
U.S. California South Belridge	Canada Syncrude Synthetic (SCO)—Alberta	Nigeria Bonny	UK Forties	Kazakhstan Tengiz	Kuwait Ratawi	Brazil Frade	Indonesia Duri
U.S. California Wilmington	Canada Suncor Synthetic A (SCO)—Alberta	Nigeria Agbami	Norway Ekofisk	Azerbaijan Azeri Light		Venezuela Hamaca	
U.S. Alaska North Slope	Canada Suncor Synthetic H (SCO)—Alberta	Angola Girassol					
U.S. Gulf Mars	Canada Cold Lake (Dilbit)—Alberta	Angola Kuito					
U.S. Gulf Thunder Horse	Canada Hibernia—Newfoundland						

Note: SCO is synthetic crude oil from upgraded oil sands; dilbit is diluted bitumen (a mixture of bitumen and diluent made from natural gas liquids, condensate, and other light hydrocarbons).

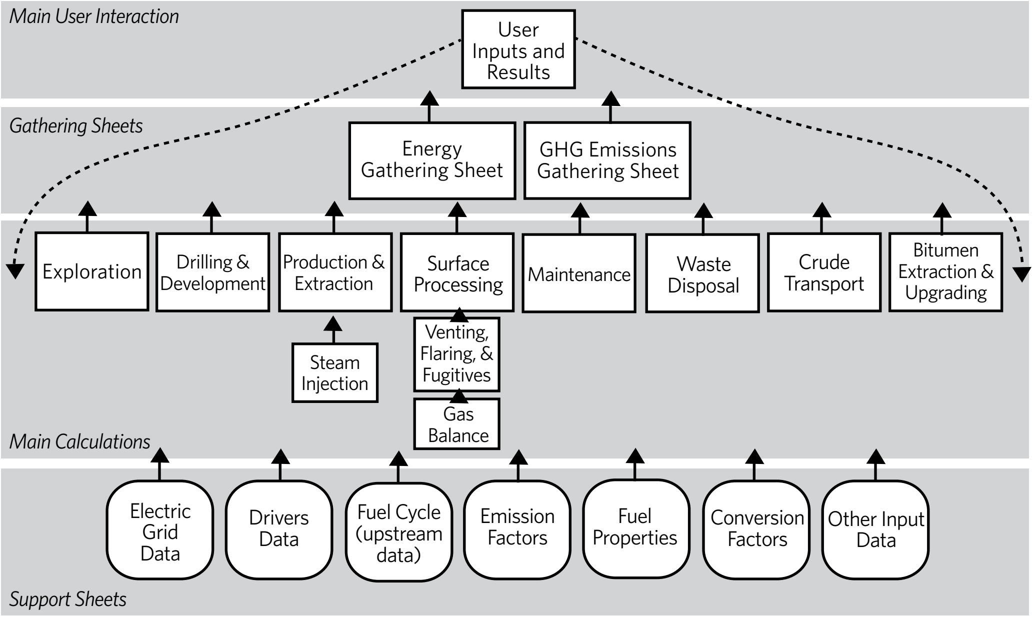
MODELING UPSTREAM OIL EMISSIONS

UNEARTHING OIL AND preparing it for transport to a refinery is the first step in the value chain. The processes involved differ from oil to oil. Together, exploration, production, surface processing, and transport of crude oil to the refinery inlet comprise upstream operations, and the resulting GHG emissions are modeled in OPGEE (see figure 2).

OPGEE PHASE 1 RESULTS

Crudes vary significantly in their upstream GHG impacts. To date, OPGEE has been run on approximately 300 global crudes, many of which are in California and Canada. This represents more upstream crude runs than any other modeling effort, including the National Energy Technology Laboratory's *Development of Baseline Data and Analysis of Life Cycle Greenhouse Gas Emissions of Petroleum-Based Fuels* (twelve crudes in November 2008); the Jacobs Consultancy's *Life Cycle Assessment Comparison of North American and Imported Crudes* (thirteen crudes in 2009); TIAX Consulting's *Comparison of North American and Imported Crude Oil Lifecycle GHG Emissions* (nine crudes in 2009); and IHS Consulting's *Comparing GHG Intensity of the Oil Sands and the Average U.S. Crude Oil* (28 crudes in 2014).

FIGURE 2
OPGEE Model Schematic



Source: Stanford University, Oil Production Greenhouse Gas Emissions Estimator

For the purposes of the Oil-Climate Index, it was critical that data were available to simultaneously model both upstream and midstream emissions. This narrowed the field down to 30 OCI test oils for the first phase.

There is large variation in upstream emissions across the 30 test oils. The oil with the highest emissions intensity has approximately twelve times the emissions of the lowest-intensity oil (see figure 3).

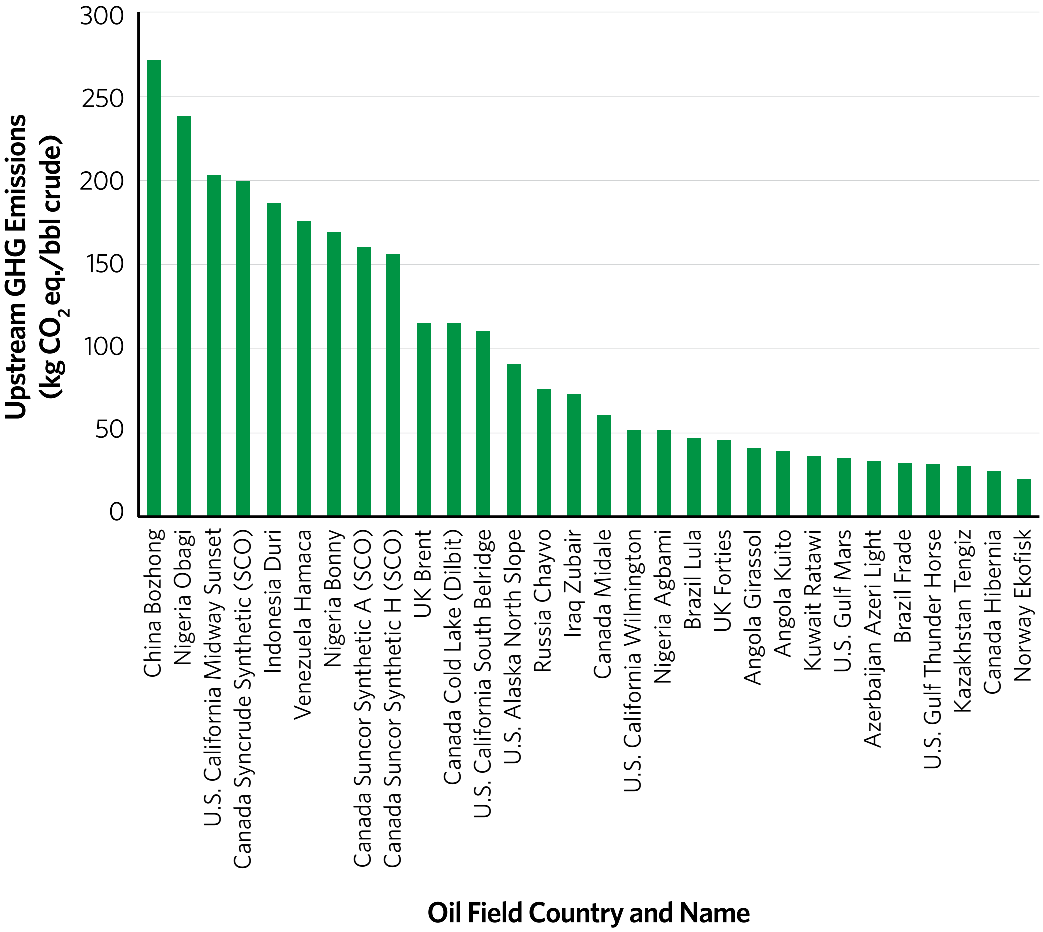
WHAT DRIVES UPSTREAM EMISSIONS?

The emissions from different oils have different origins. UK Brent, for example, emits most of its GHG emissions during surface processing, while California South Belridge emits more due to the steam used during production (see figure 4). Other upstream emissions drivers include the gas produced with the oil that may be flared or vented, depending on local conditions.

Oil location—including geography and ecosystem (such as desert, Arctic, jungle, forest, and offshore)—determines how disruptive extraction is to land use. When oil

FIGURE 3

OPGEE GHG Emission Results for 30 Phase 1 OCI Test Oils



Source: Authors' calculations

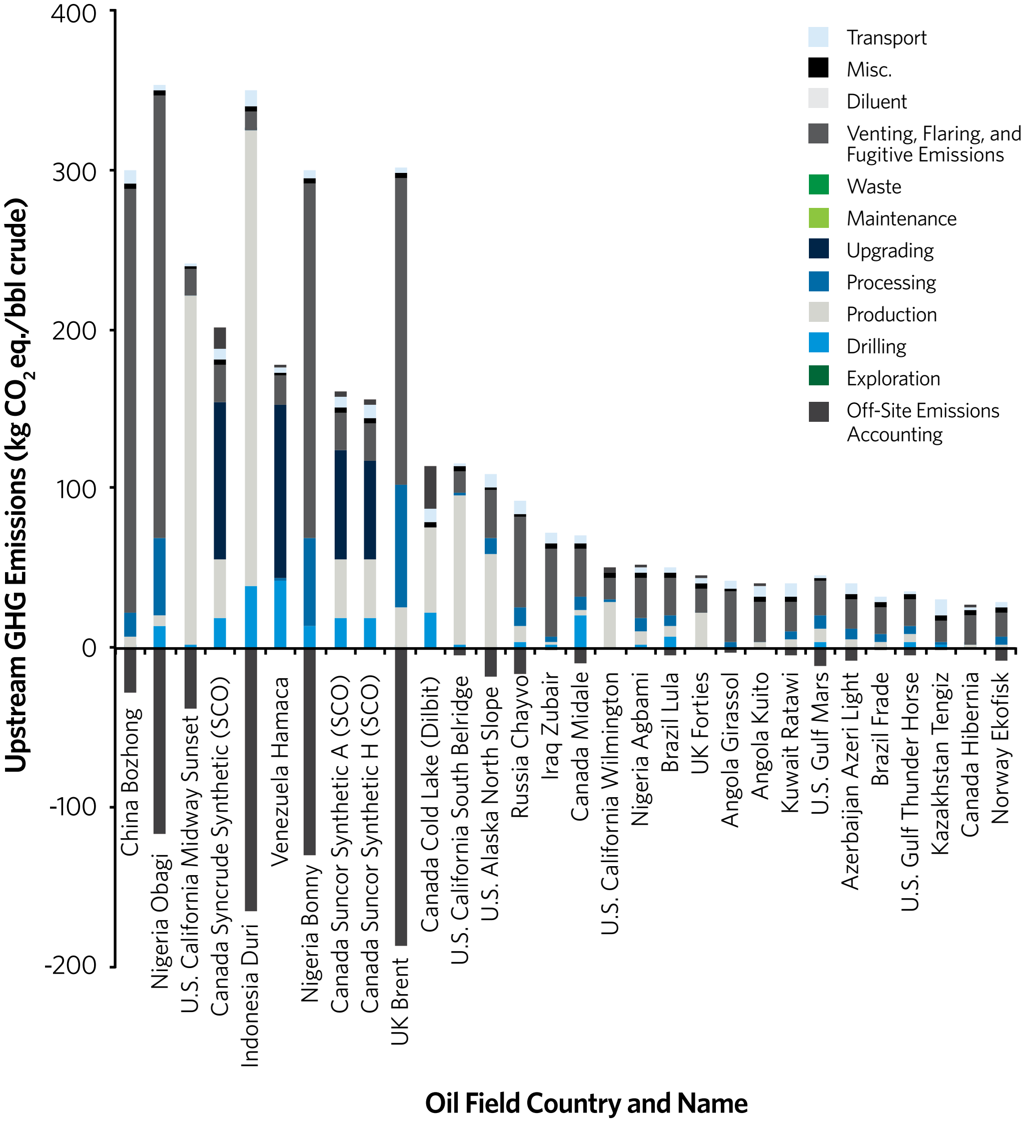
Note: Unlike the other OCI test oils, Cold Lake dilbit is not composed of a full barrel of oil. It is about 75 percent bitumen mixed with diluent to allow it to flow.

development activities change land use, this affects the land's biological (soil and plants) carbon storage capacity. The more naturally stored carbon that is released, the more greenhouse gases are emitted.

An oil field's location, its distance to transport hubs, and refinery selection determine the method that is used to move the resource and the resulting transport emissions. Pipelines, railroads, or trucks are used to ship the oil overland. Barges move oil over inland waterways, and seaborne crude shipments rely on marine tankers. In the first phase of the Oil-Climate Index, it was assumed as a default that all crude is sent to the city of Houston in Texas. As of January 2014, the U.S. states of Texas and Louisiana had more refining capacity than any nation, including China and Russia.[5]

FIGURE 4

Drivers of Upstream GHG Emissions for 30 Phase 1 OCI Test Oils



Source: Authors' calculations

Notes: Unlike the other OCI test oils, Cold Lake dilbit is not composed of a full barrel of oil. Off-site emissions accounting can be a credit (negative) or debit (positive).

OPGEE analysis points to a number of factors that result in particularly high upstream emissions:

- The methods used to recover extra-heavy (bitumen) and heavy oils often involve putting significant amounts of energy in to heat up resources so they can flow, consuming 10–30 percent of the energy content of the produced crude. These oils also typically have significant water-handling and treatment needs, and pumping water is energy-intensive.
- Ultra-light and light oils that have a high level of associated gas may be flared if gas-handling infrastructure is inadequate or missing. Disposing of this gas through flaring instead of gathering and selling it results in additional carbon dioxide emissions. This wasteful practice produces GHG emissions with no economic benefit.
- Hydraulically fractured oils can vent methane emissions due to gas flowback, which is when vapors return to the surface. This can happen when an oil well has been drilled and the piping and tubing infrastructure that has been put in place for ongoing production cannot adequately contain the gas associated with the oil.
- Conventional oil formations that are depleted and are running out of oil resources can produce significant quantities of water or require increased injection of substances to induce oil production.

OPGEE CHALLENGES

The largest source of uncertainty in OPGEE is the lack of information on global oil fields. Many operators and many regions of the world have few formal data publication requirements. Data quality is also an ongoing issue in modeling upstream emissions (see the appendix for details).

OPGEE utilizes about 50 data inputs, from simple entries like the name of the country where an oil field is located to challenging-to-obtain information such as an oil field's productivity index (expressed in daily production per unit pressure). Substantial research is involved in gathering OPGEE modeling data, which can be obtained from agencies, reports, scientific literature, and industry references.

OPGEE can function with limited data. The model has a comprehensive set of defaults and smart defaults that can fill in missing data. The more data found for a particular field, the more specific and less generic the emissions estimate becomes. All data are used to determine smarter default values over time.

As with all life-cycle assessment (LCA) models, boundaries must be drawn around the analysis. The handling of co-products that cross boundaries along the oil supply chain, from extraction to refining to end use, presents methodological challenges. For example, resulting GHG emissions from condensates of light liquids, like ethane, that can be stripped off and sold before oil is transported to a refinery are not expressly included in OPGEE. Emissions associated with exploration occur at the beginning of an oil field development project and are spread over the life of the field. Extraction emissions that occur routinely are estimated at a point in time and assumed to recur over the lifetime of the oil field.

OPGEE treats liquid petroleum as the principal product of upstream processes. Emissions associated with electricity generated on-site or natural gas produced that is gathered, sold, and not flared is credited back or deducted from total emissions in OPGEE accounting (see figure 4 above).[6] Any emissions from co-products like petcoke that are associated with upgrading heavy oils upstream of the refinery—as can be the case with Canadian bitumen and Venezuelan heavy oils—are not included in OPGEE unless the production process directly consumes petcoke (as in some oil-sands-based integrated mining and upgrading operations). Emissions from net production of petcoke have been included in the OPEM downstream combustion module.

Recent studies have found that uncertainty in OPGEE's results is reduced after learning three to four key pieces of data about an oil field.[7] After learning the ten most important pieces of information about an oil field, there is typically little benefit to learning the remaining data.

Imprecise data reporting introduces additional uncertainty. Errors in applying the model can lead to further uncertainty.

The key variables to enhance model precision include: steam-to-oil and water-to-oil ratios, flaring rates, and crude density (measured as API gravity). Less important variables in the OPGEE model's ability to analyze GHG emissions include gas-to-oil ratios, oil production rates, and depth (except in extreme cases).

MODELING MIDSTREAM OIL EMISSIONS

REFINERIES ARE AKIN to a professional chef's kitchen. Instead of edible organic foodstuff, the ingredients are hydrogen, carbon, oxygen, and a multitude of impurities. Refinery equipment—effectively the stoves, refrigerators, pressure cookers, mixers, and bowls—heats, cleaves, blends, and reconfigures the massive flows of hydrocarbons it is fed.

Refining used to be a relatively simple process that involved applying heat to boil oil and separating it into its main components. But the changing nature of oil demands changes in refineries.

The changing nature of oil demands changes in refineries.

PRELIM is the first open-source refinery model that estimates energy and GHG emissions associated with various crudes processed in different refinery types using different processing equipment. It provides a more detailed investigation into the impacts crude quality and refinery configurations have on energy use and GHG emissions than what has been presented in the public realm to date. PRELIM can run a single crude or a blend of oils, and when combined with OPGEE, the model provides the second of the three components in the improved oil life-cycle assessment.

PRELIM influences the Oil-Climate Index in two important ways. It estimates midstream GHG emissions, and it predicts what petroleum commodities the refinery produces. The type and amount of products vary with a refinery's design.

MATCHING OILS TO REFINERIES

Every refinery is unique in terms of the combination of equipment it uses, the blends of crudes it is optimized for, and ultimately the type and amount of products it sells. Matching oil characteristics with refining infrastructure in order to meet end-use product demand is the midstream goal.

PRELIM attempts to represent many of these possible refinery configurations by including three different types of refinery—hydroskimming, medium conversion, or deep conversion—and ten combinations of processing units within refinery categories (see figure 5). One configuration, for example, employs a coking unit in a deep conversion refinery to reject high levels of carbon in the form of petcoke. Another example is configuring a refinery with hydrotreating for adding hydrogen.

The inputs and outputs of each refinery process unit are estimated using characteristics about individual process units from existing literature and industry-expert input as well as characteristics of the crude or crude blend.

Technically, each crude can be blended and processed in many different refinery configurations, but in practice crude oils are best matched to certain configurations. PRELIM selects the default refinery configuration that best suits a crude oil based on its properties (API gravity and sulfur content). This means that light and sweet (low sulfur) crudes will be processed in simpler refineries and heavy and sour (high sulfur) crudes will be directed to complex deep conversion refineries.

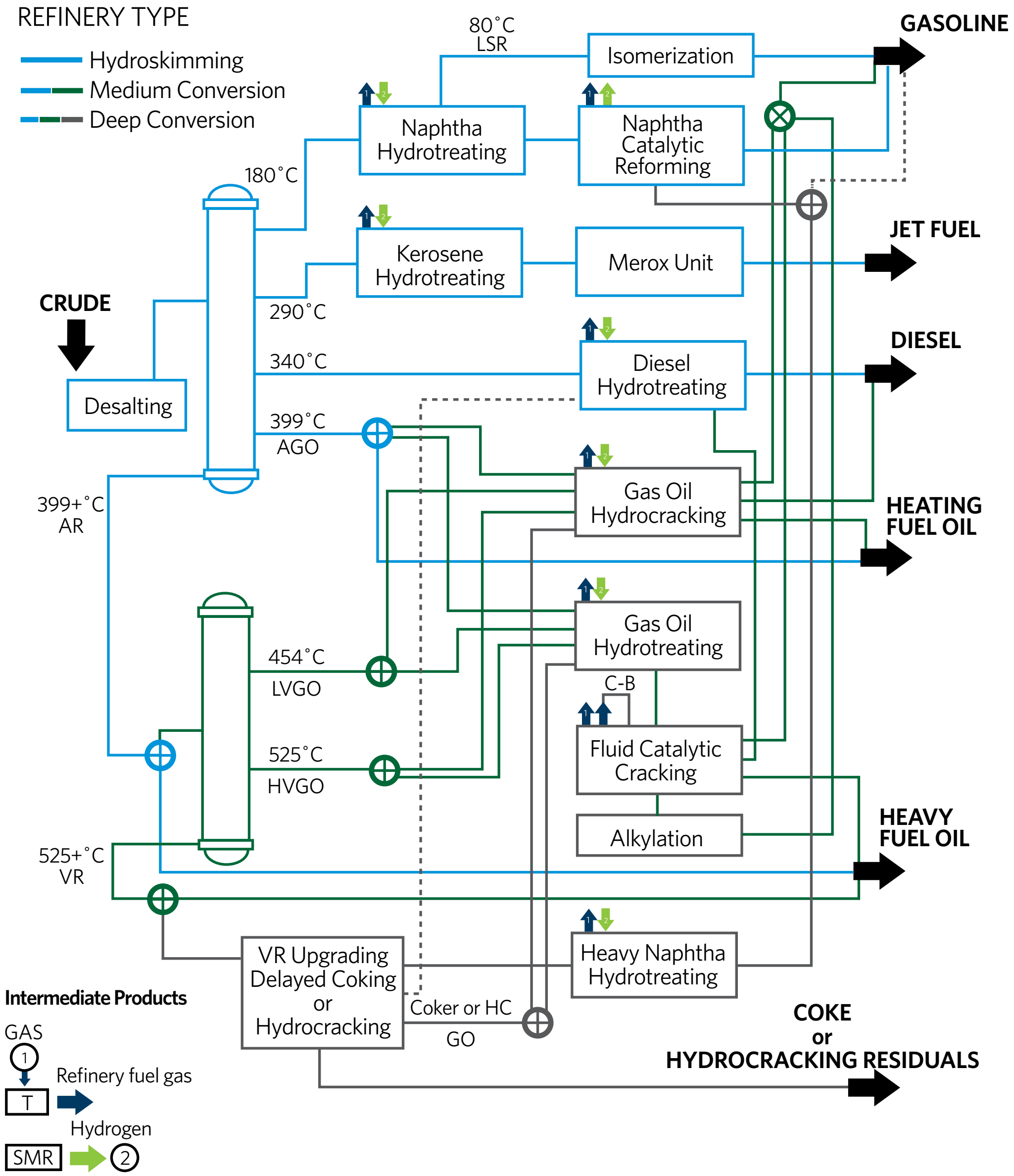
Specifically, PRELIM matches refineries with crudes as follows:

- Deep conversion refinery: heavy crude with any sulfur level
- Medium conversion refinery: medium sweet crude (22 to 32 API, with less than 0.5 percent sulfur content by weight); medium sour crude (22 to 32 API with more than 0.5 percent sulfur content by weight); and light sour crude (over 32 API with more than 0.5 percent sulfur content by weight)
- Hydroskimming refinery: light sweet crude over 32 API and less than 0.5 percent sulfur content by weight

While API gravity and sulfur are good indicators of a default refinery type, they are not sufficient to determine refinery GHG emissions. Therefore, the user of the model can override the default refinery configuration. For example, California Midway Sunset oil, with a reported API gravity as high as 22.6 and as low as the teens, was run through a deep conversion rather than a medium conversion refinery. Once the refinery configuration is selected, detailed information about the particular oil is needed well beyond API gravity and sulfur content of the whole crude.

FIGURE 5

Refinery Configurations in PRELIM



Source: Petroleum Refinery Life-Cycle Inventory Model

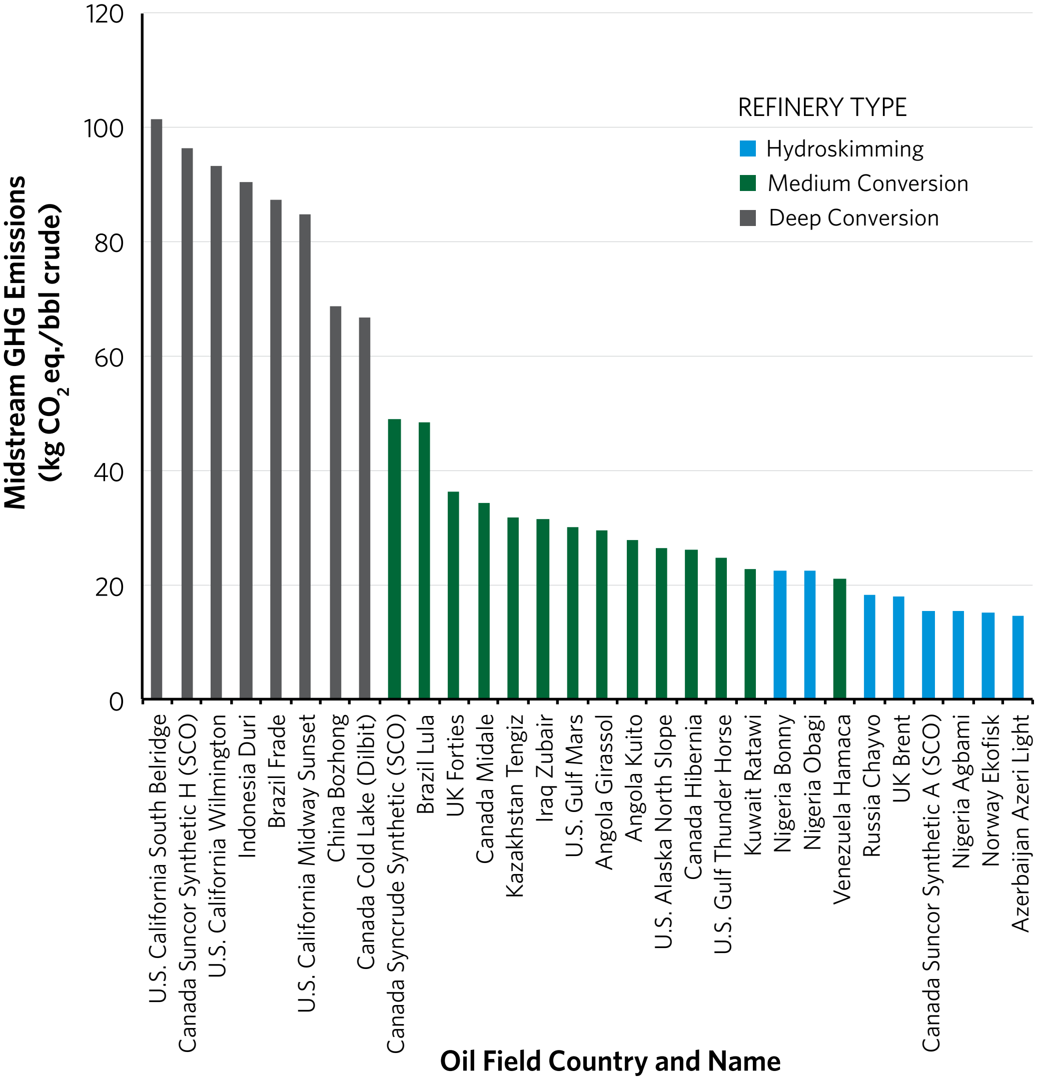
Note: See list of acronyms for more information.

PRELIM PHASE 1 RESULTS

During Phase 1, sufficient data were collected on 57 oils to run through PRELIM using a float case that allows the model to determine petroleum product yields rather than fixing production volumes.[8] The results for those 30 test oils where there was sufficient data to also run OPGEE show that midstream GHG emissions vary by a factor of seven (see figure 6).

FIGURE 6

PRELIM GHG Emission Results for 30 Phase 1 OCI Test Oils



Source: Authors' calculations

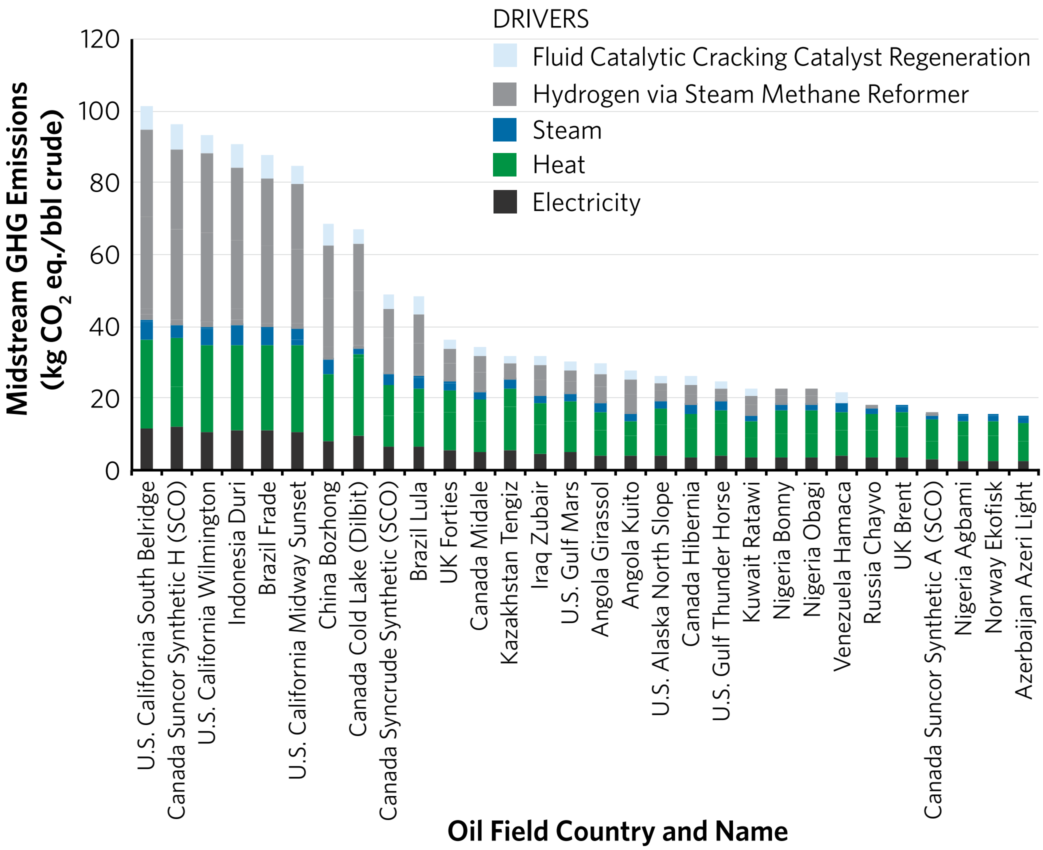
Notes: The 30 test oils were run through a delayed coking refinery as well. Hydrocracking facilities are also possible to model in PRELIM. Medium and deep conversion refineries use fluid catalytic cracking (FCC) and gas oil-hydrocracking (GO-HC) processes. Unlike the other OCI test oils, Cold Lake dilbit is not composed of a full barrel of oil.

WHAT DRIVES MIDSTREAM EMISSIONS?

Recent work with PRELIM finds a number of factors that lead to high amounts of emissions during midstream petroleum operations (see figure 7). PRELIM is also useful in identifying where GHG emissions can be reduced in the refining process.

FIGURE 7

Drivers of Midstream GHG Emissions for 30 Phase 1 OCI Test Oils



Source: Authors' calculations

Note: Unlike the other OCI test oils, Cold Lake dilbit is not composed of a full barrel of oil.

Crude quality and the selected process units employed (that is, the refinery configuration), as well as the energy efficiency of the process units, all play important roles in determining the energy requirements and emissions of an individual crude (or a crude blend).

The unique amount of hydrogen required to process each crude is the major driver of refinery energy use and GHG emissions. The amount is dictated by the quality of the crude entering the refinery. Lighter crudes yield more hydrogen when refined, while heavier crudes lack hydrogen and often utilize hydrogen inputs during refining.

Based on this analysis, the top three ways to reduce GHG emissions at refineries that process heavier crude are to reduce the amount of hydrogen consumed, increase hydrogen production efficiency (and/or lower the GHG emissions intensity of hydrogen production), and capture carbon dioxide from the most concentrated, highest volume refinery sources. Those sources include fluid catalytic cracking units used to produce additional gasoline and steam methane reformer units used to make hydrogen on-site from natural gas.[9]

PRELIM CHALLENGES

Many experts think that a crude oil's API gravity and sulfur content are reliable predictors of refinery GHG emissions. This, however, is a fallacy that has long hampered the collection of the full range of data needed to model midstream emissions.

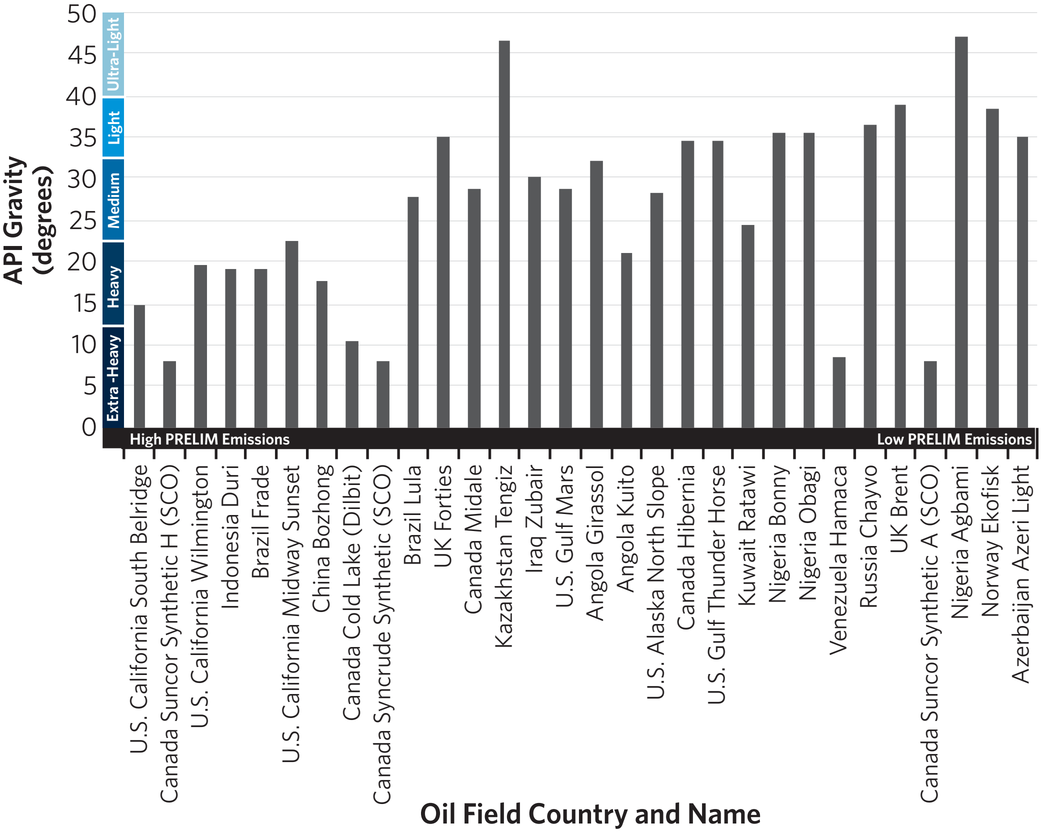
OCI results illustrate this point. Ranking oils by their PRELIM emissions from high to low and plotting them in this order yields little or no correlation with API gravity (see figure 8). A similar mismatch results for sulfur and hydrogen content.

Similar to OPGEE, PRELIM faces typical LCA challenges such as data quality, transparency, and availability, as well as ambiguity associated with analysis boundaries and assumptions. Given the complexity and uniqueness of operating refineries and crudes produced around the world, any model that attempts to estimate refinery emissions will always include uncertainties. The major sources of uncertainty in PRELIM stem from gathering input data from the public realm and the fact that PRELIM results can be sensitive to many dynamic parameters.

Given the complexity and uniqueness of operating refineries and crudes produced around the world, any model that attempts to estimate refinery emissions will always include uncertainties.

An oil assay, or a chemical analysis of crude, reported in a consistent format is a particularly important PRELIM input. Assays provide extensive, detailed experimental data for refiners to establish the compatibility of a crude oil with a particular petroleum refinery. These data also determine if individual crudes fulfill market-driven product yield, quality, and demand, and they are used to determine if a refined crude will meet environmental, safety, and other standards. Assays guide plant operation, development of product schedules, and examination of future processing ventures. They supply

FIGURE 8
API Gravity of 30 Phase 1 OCI Test Oils in Order of PRELIM GHG Emissions



Source: Authors' calculations

engineering companies with crude oil analyses for their process design of petroleum refining plants, and they help determine companies' crude oil prices and set cost penalties for unwanted impurities and other undesirable properties.

PRELIM requires detailed oil assays that are routinely collected (specifics are available in the appendix).[10] Unfortunately, assay data reports are often inconsistent, lacking permission to use or reprint, or unavailable publicly at all. Standardized, updated, and consistent public oil assays that measure the same factors and abide by the same temperature cut points are needed to understand midstream oil emissions and product volumes that drive downstream emissions.

This situation calls for more robust oil data collection and reporting. Not only does such accuracy affect climate change impact estimates, it also can have safety impacts. Knowing an oil's characteristics can determine how to establish operating procedures for different oils when they move by rail, pipeline, and other transport modes.

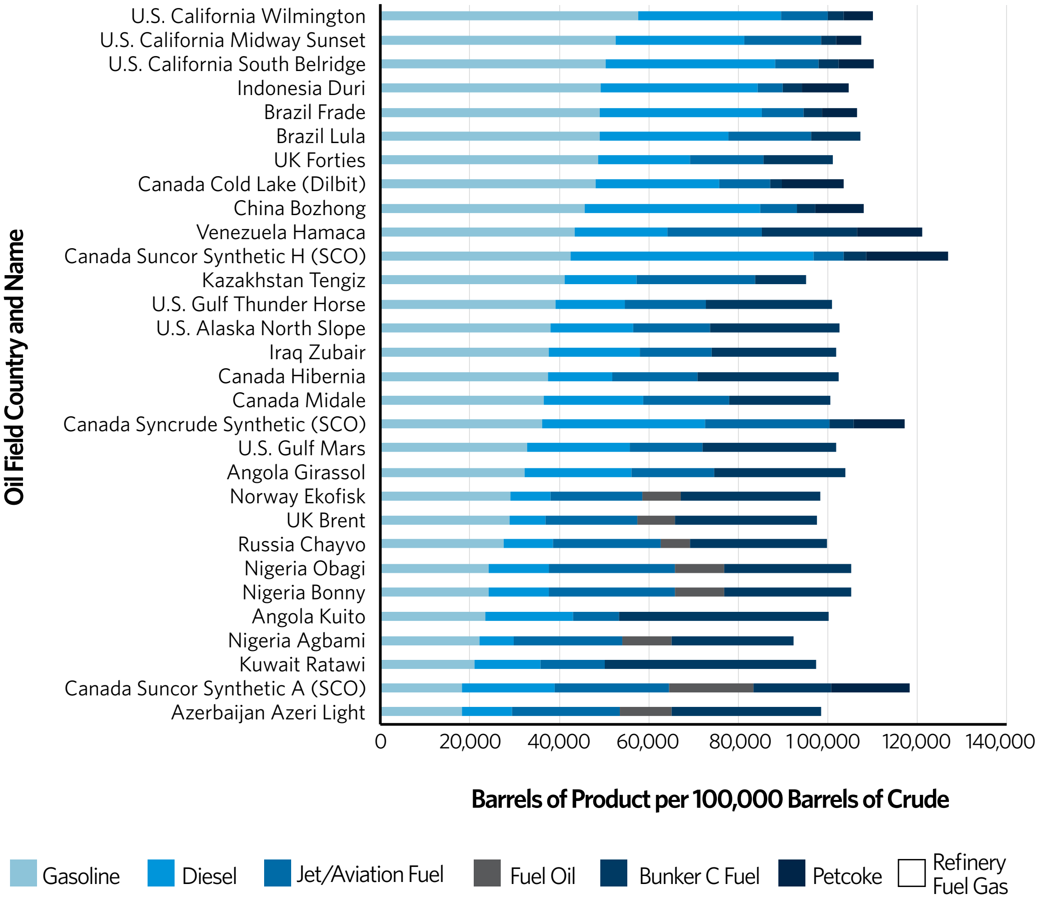
MODELING DOWNSTREAM OIL EMISSIONS

THE TRANSPORTATION OF crude oil from the field to the refinery is captured in the OPGEE model. But there are also emissions from transporting petroleum products—gasoline, diesel, jet fuel, and other co-products—from the refinery outlet to domestic and global markets. This transport and use of refined petroleum products are the final inputs needed to calculate an oil's GHG emissions. OPEM uses the product outputs from PRELIM to calculate emissions from transport and end use (see figure 9).

The globalization of the oil sector has increased movement of these products in recent years. Refineries are no longer located predominantly in regions where demand is greatest. The United States, for example, has been refining a growing surplus of diesel fuel that it exports to Europe and Asia. Default values have been included in the Oil-Climate Index's downstream module according to a given route that petroleum products may take from Houston (where OPGEE assumes all crudes are refined) to the northeastern United States. This represents a lower bound for transport emissions; it does not consider long-distance international petroleum trade. The amount of GHG emissions from product transport varies depending on the methods used and distances traveled, but current OPEM defaults result in a lower bound of transport emissions at 1 to 2 percent of total emissions.

FIGURE 9

PRELIM Product Outputs for 30 Phase 1 OCI Test Oils



Source: Authors' calculations

Notes: Petcoke production is total for refinery (for heavy oils) and upstream upgrading (for SCO). PRELIM currently assumes all refinery fuel gas (RFG) is used in the refining process. Unlike the other OCI test oils, Cold Lake dilbit is not composed of a full barrel of oil.

While transport emissions are minor relative to those stemming from other parts of the life cycle, end use dominates oil's GHG emissions. Prior LCA calculations have historically compared oil to alternative transport fuels.[11] As such, GHG emissions were measured predominantly on the basis of gasoline or diesel yields. But significant and variable emissions result from use of an oil's entire product slate, including petrochemical feedstock, which will be formally added to the product slate in OCI Phase 2, and bottom-of-the-barrel co-products like petcoke, fuel oil, bunker fuel (known as bunker C), and asphalt. This highlights the fact that the fate of the entire oil barrel is critical to understanding and designing policies that reduce an oil's GHG emissions.

PRODUCT TRANSPORT EMISSIONS

Three variables determine the emissions from the transportation of refined products: mode, distance, and the mass of the product. Different transport modes have different emission intensities.[12] If a tonne (metric ton) of fuel is shipped 1 kilometer, tanker trucks have the highest GHG emissions (0.09 kilograms of carbon dioxide equivalent per tonne-kilometer) while ocean-going crude carriers have the smallest emissions per tonne-kilometer (0.003 kilograms). Rail and pipeline emission factors are 0.02 and 0.01, respectively. For example, an average heavy-duty tanker truck moving a tonne of gasoline 1 kilometer emits as much as an ocean tanker moving a tonne 30 kilometers.

The energy needed and greenhouse gases emitted transporting refined products increases with distance and mass. PRELIM product outputs (converted from barrels to tonnes using reported product densities) are used to determine how much is transported to the marketplace; however, the distance that gasoline, diesel, jet fuel, petcoke, and other products are transported is difficult to determine. Limited and inconsistent data exist on the distances that products travel because there is no global agency or group to collect and audit such data. Collecting such data is also challenging because products are often shipped around the globe, trades tend to involve multiple actors that are frequently private firms, and product flows are highly dynamic, driven by changing supply and demand.

For the first phase of the Oil-Climate Index, default values for downstream product transport emissions represent a rough estimate of a typical (but not an average) distance traveled by truck and ocean tanker for the total mass of petroleum products for each crude. For example, default values of 2,414 kilometers (roughly 1,500 miles) by pipeline from Houston to the New York–New Jersey region and then 380 kilometers (about 236 miles) by tanker truck to the Boston region were selected.

END-USE COMBUSTION EMISSIONS

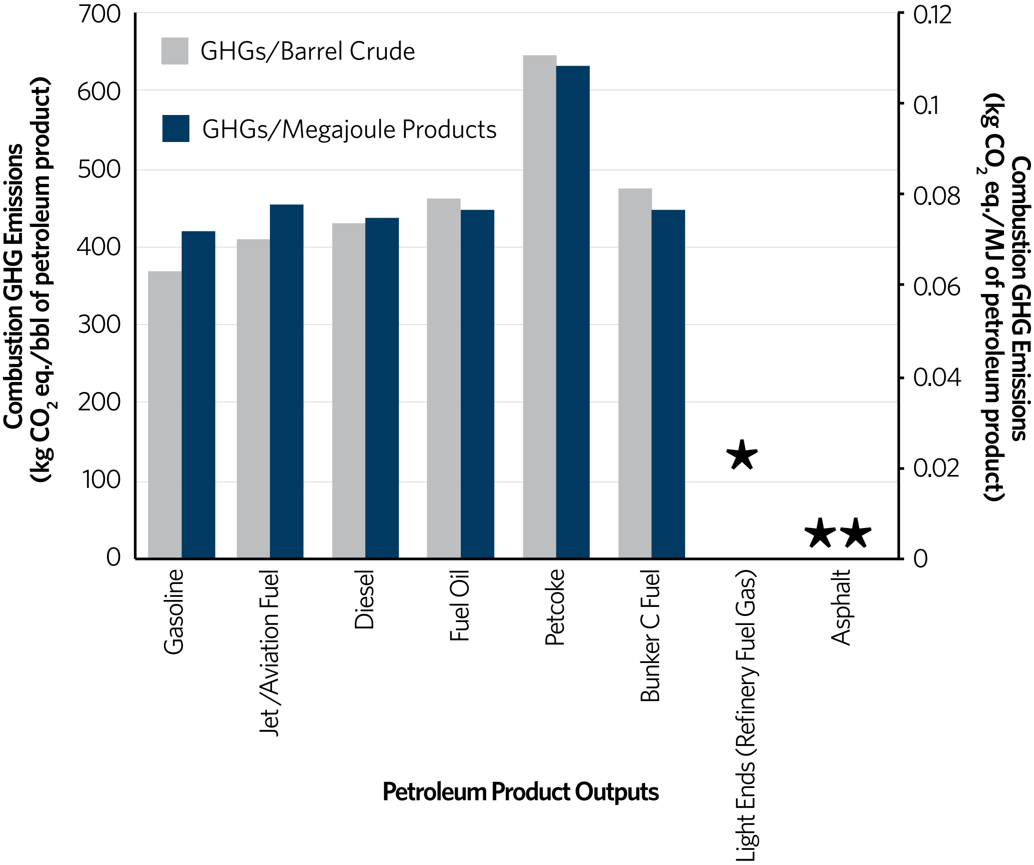
Most hydrocarbon products are used to release energy to power cars, trucks, planes, trains, generators, and power plants. However, some petroleum products, like asphalt, hydrogen, and the refinery gases that make up petrochemical feedstock, derive their greatest economic value without being burned.

In order to calculate GHG emissions from petroleum product combustion for sample oils, each product's emission factor needs to be identified. The U.S. Environmental Protection Agency has been measuring, tracking, and updating emission factors since 1972.

Each barrel of combusted petroleum products has different emissions, ranging from gasoline at 370 kilograms of CO_2 equivalent per barrel to petcoke at 645 (see figure 10). The quantity of products produced from a given crude from PRELIM determines the overall emissions from combustion for that oil.

FIGURE 10

Petroleum Product Combustion-Related Emission Factors



Source: U.S. Environmental Protection Agency, “Emission Factors for Greenhouse Gas Inventories,” www.epa.gov/climateleadership/documents/emission-factors.pdf

Notes: Emission factors most recently updated in April 2014.

* Light ends can be used as petrochemical feedstock, and refinery fuel gas (RFG) is a subset of light ends. When the resource is not combusted, it results in no GHG emissions; but when it is burned as RFG, it has an estimated emission factor ranging from 160 to 370 kilograms of CO_2 equivalent per barrel.

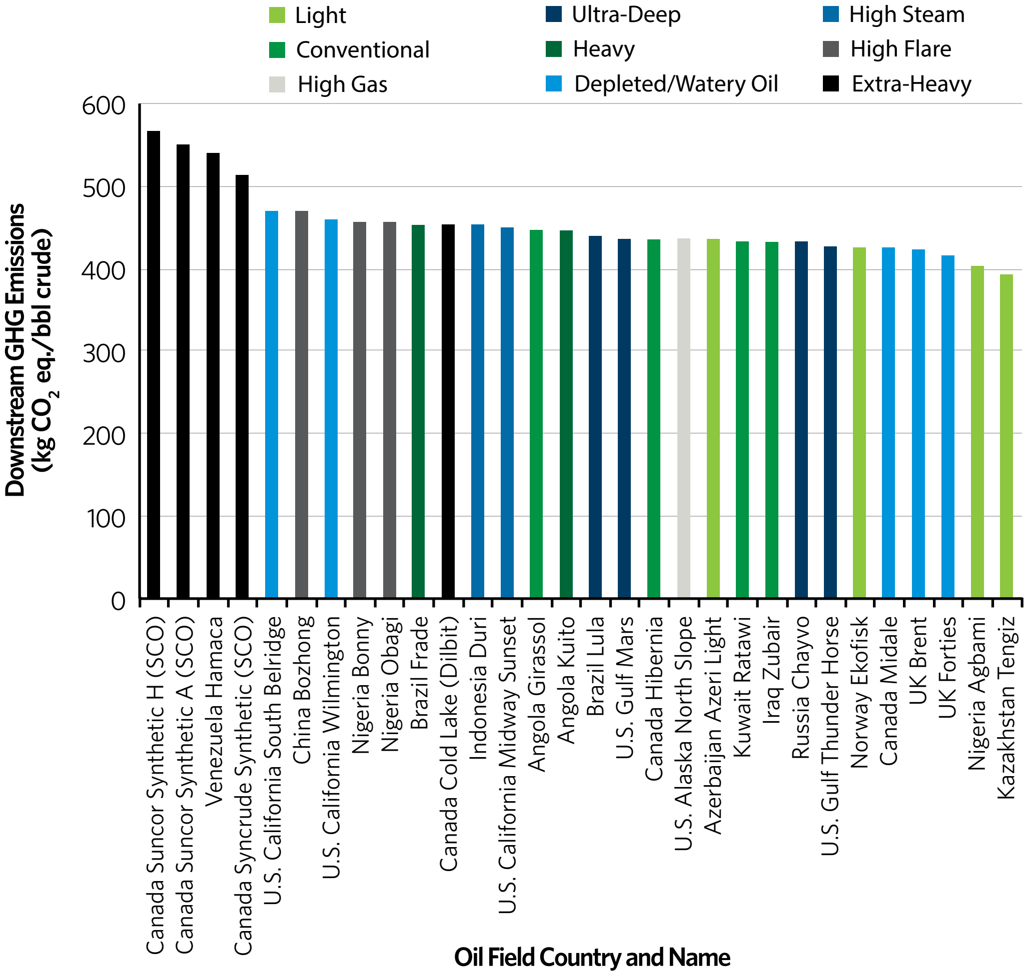
** Asphalt is not burned and, therefore, has no direct combustion emission factor when it is used to pave roadways, but it may result in emissions of up to 500 kilograms CO_2 equivalent per barrel product when heated for road oil or roofing or combusted for other uses.

OPEM PHASE 1 RESULTS

Although the downstream combustion of petroleum products accounts for the largest portion of overall emissions, there is variability between oils—a 45 percent spread between the combustion emissions of the 30 OCI test oils (see figure 11). The heaviest oils have higher combustion emissions while lighter oils have lower combustion emissions. Canada's Suncor Synthetic H synthetic crude oil (or SCO), an upgraded bitumen-based oil sand, has combustion emissions of nearly 565 kilograms of CO_2 equivalent per barrel of crude, whereas Kazakhstan Tengiz oil is estimated to yield a petroleum product slate that emits 390 kilograms per barrel. This range of absolute variation (155 kilograms CO_2 equivalent GHG emissions) is almost equal to the absolute range in upstream emissions shown in figure 3.

FIGURE 11

OPEM GHG Emission Results for 30 Phase 1 OCI Test Oils



Source: Authors' calculations

Note: Unlike the other OCI test oils, Cold Lake dilbit is not composed of a full barrel of oil.

OPEM CHALLENGES

The main uncertainties that arise regarding downstream emissions are related to product outputs from PRELIM. Combustion emission factors, which have been measured for decades, are updated routinely, and have less uncertainty associated with them, although as product specifications and engines change over time, so too will emission factors. And small changes in emission factors can lead to large changes in total emissions given large product output volumes.

Product transport emissions, meanwhile, are highly uncertain. But they are thought to be relatively small, except in possible extreme cases. The routes and distances different products take from the refinery to market are highly variable and largely opaque. Changing trade patterns are rarely disaggregated by product. Domestic as well as transnational petroleum product movements are often not made public. Without origin-to-destination data from refineries to end point, it is highly uncertain what modes and distances products travel and the emissions they cause.

OVERALL RESULTS FROM OCI PHASE 1

PUTTING THE PIECES of the Oil-Climate Index together results in the total GHG footprint for different oils. Results are reported per barrel of crude input (see figure 12). There is an over 80 percent difference between the highest GHG-emitting oil and the lowest on a per barrel basis. Since the selection of which oils to analyze in Phase 1 was influenced by data availability, it is impossible to know if this sample includes the full range of oils' emissions.

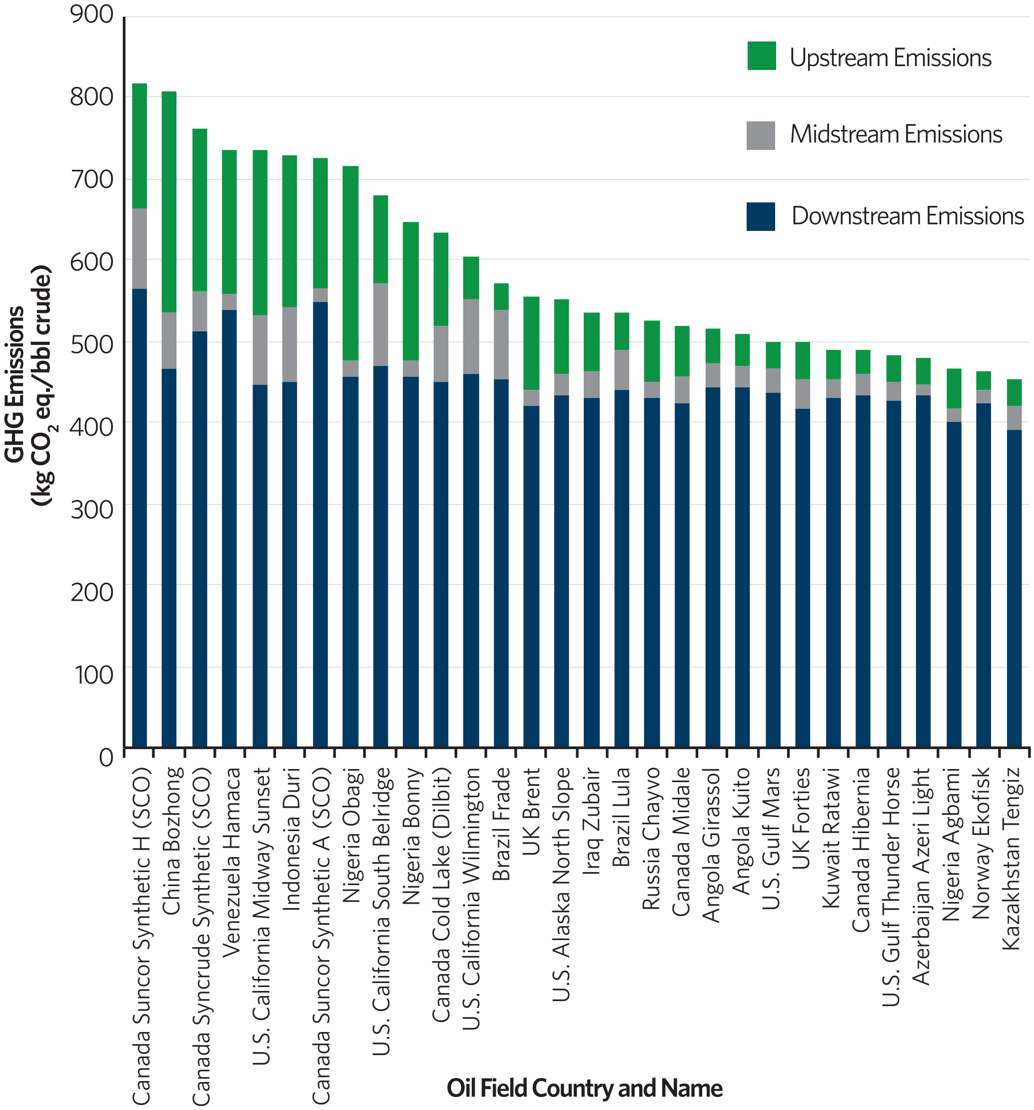
The share of total GHG emissions from different parts of the oil supply chain varies widely by oil. OPGEE emissions range from under 5 percent to 33 percent for different oils, PRELIM emissions range from 3 to 15 percent, and OPEM emissions range from 60 to 90 percent.

The Oil-Climate Index selects oil volume (per barrel of crude) as the default basis. But emissions are also reported per unit of energy (per megajoule of product), or by product value (in dollars of product) (see figure 13).

When emissions are calculated per megajoule or dollar value of petroleum products delivered, a similar, variable relationship holds as when measured per barrel of crude oil.

FIGURE 12

Total GHG Emissions for 30 Phase 1 OCI Test Oils



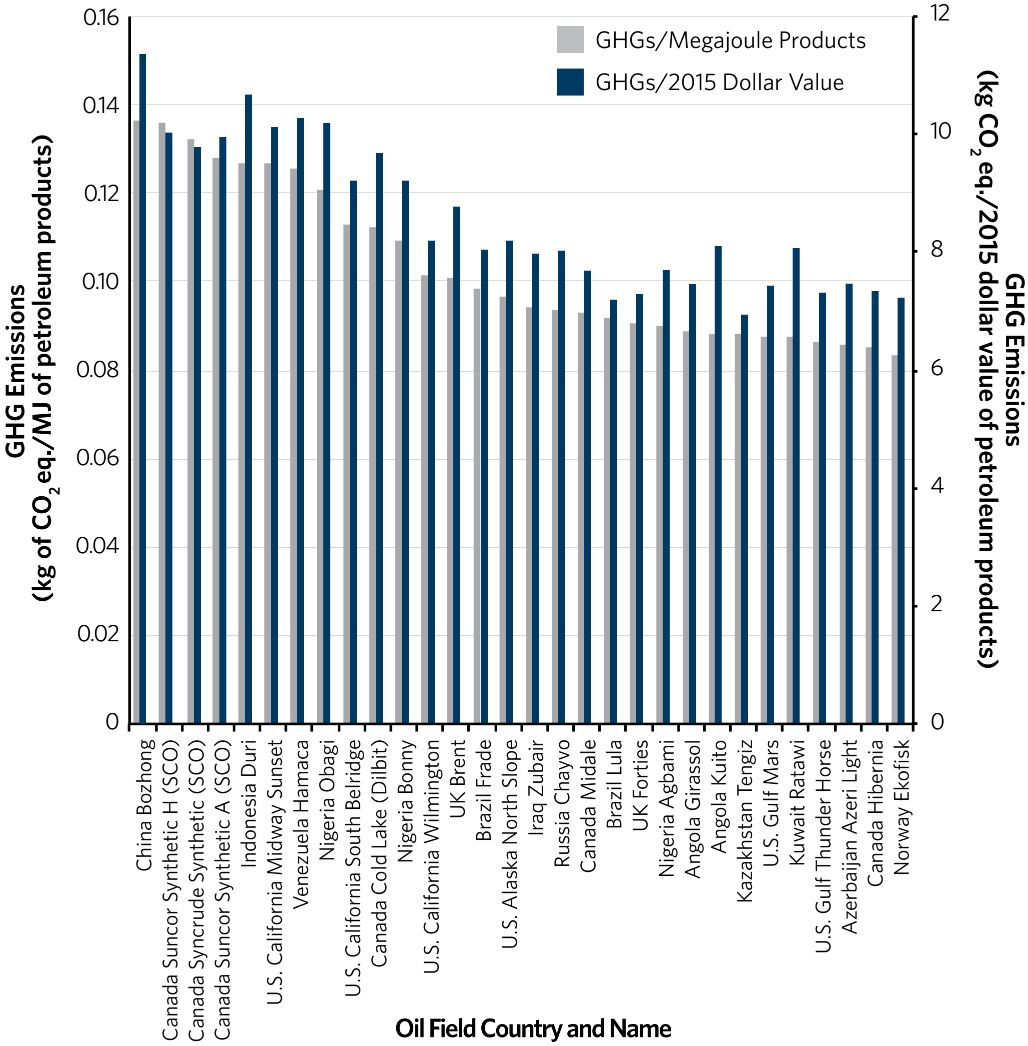
Source: Authors' calculations

Note: Unlike the other OCI test oils, Cold Lake dilbit is not composed of a full barrel of oil.

The different functional units for comparing emissions—per barrel of oil, per megajoule of petroleum products, and per dollar value of petroleum products—reported in the index are all reasonably well correlated (see figure 14). In other words, those oils with greater per barrel GHG emission footprints, such as extra-heavy synthetic crude oils from Canada, heavier depleted oils from California, and highly flared oils from Nigeria, appear to also have higher emissions per U.S. dollar and per megajoule.

FIGURE 13

Total GHG Emissions per Megajoule (left) and per Dollar (right) for 30 Phase 1 OCI Test Oils

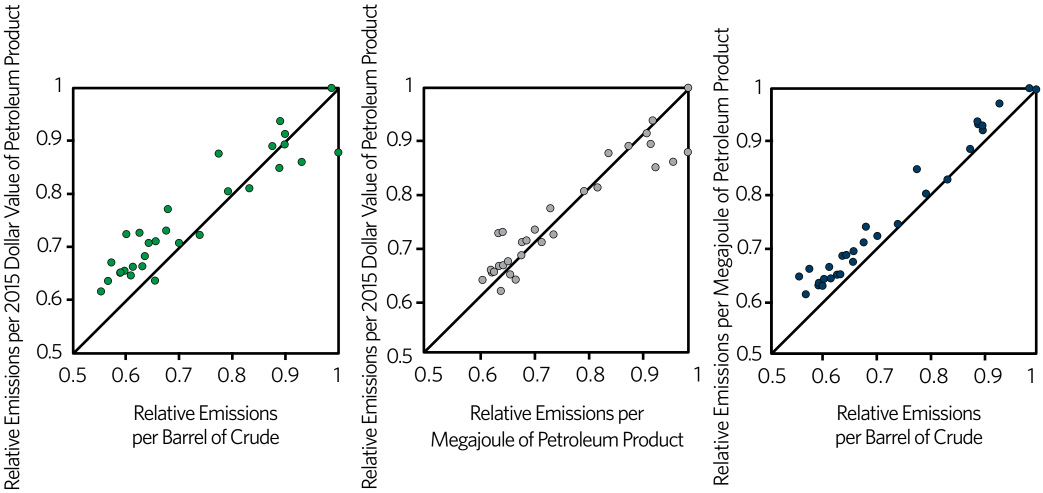


Sources: Authors' calculations; U.S. Energy Information Administration, "Spot Prices," February 9, 2015, www.eia.gov/dnav/pet/pet_pri_spt_s1_d.htm; U.S. Energy Information Administration, "Refiner Petroleum Product Prices by Sales Type," February 9, 2015, www.eia.gov/dnav/pet/pet_pri_refoth_dcu_nus_m.htm; and Argus Media Ltd., "Energy Argus: Petroleum Coke," July 2014, www.argusmedia.com/~/media/-Files/PDFs/Samples/Energy-Argus-Petroleum-Coke.pdf?la=en

Note: Petcoke prices are from 2014 data; all other petroleum products are from 2015 data. Unlike the other OCI test oils, Cold Lake dilbit is not composed of a full barrel of oil.

FIGURE 14

Parity Charts of OCI Functional Units for 30 Phase 1 OCI Test Oils



Source: Authors' calculations

Notes: 1 equals highest value in all graphs. Petcoke prices are from 2014; all other petroleum products are from 2015 data.

FINDINGS AND RECOMMENDATIONS FROM OCI PHASE 1

THE OIL-CLIMATE INDEX was developed to alert stakeholders to the full array of climate impacts of oil from various perspectives, with an eye toward informing investment, development, operations, and governance of the oil supply chain. The index provides new knowledge that these stakeholders can take into account to make more informed, strategic, and durable decisions about oil development.

Investors, policymakers, and other stakeholders must evaluate oils based on their individual energy factors and GHG emissions, which vary significantly from oil to oil, and take this information into account when making public and private decisions.

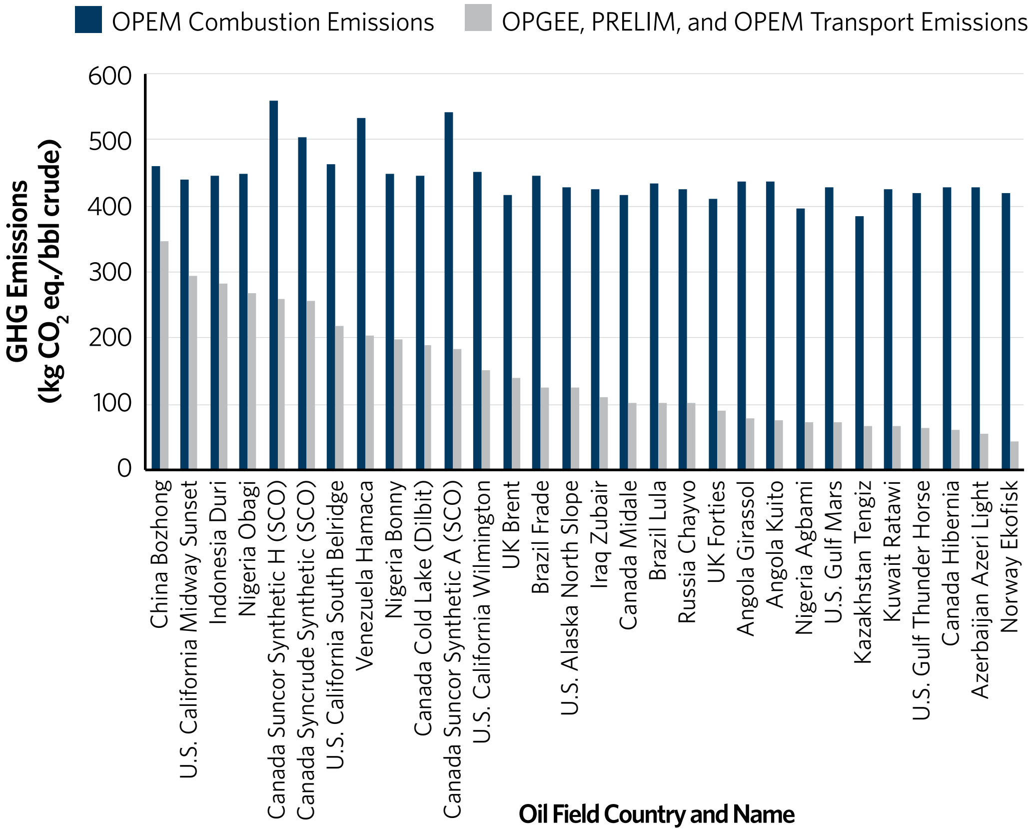
KNOW YOUR OIL

For certain oils, the end products cast nearly as large a GHG footprint as the greenhouse gases produced to extract, refine, and transport them to market (see figure 15). Of the Phase 1 test oils, in addition to Canada Syncrude Synthetic (SCO) and China Bozhong, California Midway Sunset, Indonesia Duri, and Nigeria Obagi have some of the highest costs in climate terms.

Investors, policymakers, and other stakeholders must evaluate oils based on their individual energy factors and GHG emissions, which vary significantly from oil to oil, and take this information into account when making public and private decisions.

FIGURE 15

Comparing GHG Emissions of Oil Supply Chain Inputs and Outputs for 30 Phase 1 OCI Test Oils



Source: Authors' calculations

Note: Unlike the other OCI test oils, Cold Lake dilbit is not composed of a full barrel of oil.

OPEN-SOURCE INFORMATION IS KEY

New knowledge about oil is a critical ingredient for climate decisionmaking. As new oil and other oil-bearing hydrocarbon resources are discovered and technology advances to facilitate their development, new challenges will surface. If history is any guide, this information will likely be inconsistent and randomly reported by industry, governments, and the media. Intellectual property restrictions will limit the usability of data. And arbitrary restrictions on government data collection will make the task of full life-cycle assessment of emissions much more difficult.

Open-source information about oil should be made more accessible and widely available through reporting guidelines and regulatory reform that requires consistent, comparable, and verifiable data (see appendix for more details).

CREATE NEW OIL-CLIMATE CLASSIFICATIONS

Total GHG emissions are found to be generally higher in certain classes of oils. The Oil-Climate Index identifies three oil categories that (per barrel) result in higher GHG emissions than other oils: extra-heavy oils, oils whose associated gas is flared, and oils that are high in water or in largely depleted fields with large steam requirements during production (see table 2).

As oils become more unconventional over time, the number and types of oil classifications that are common today are likely to expand. For example, developments related to organic kerogen strewn throughout sedimentary rocks, oils buried in permafrost and elsewhere in the Arctic, bitumen trapped in solid carbonate formations or surrounded by water, turning coal or gas into liquid petroleum products, methane gas trapped in ice, or refinery designs that produce new types of petroleum products could require adding categories of oils to the index in the future.

TABLE 2
Designated Oil-Climate Categories for 30 Phase 1 OCI Test Oils

Light	Conventional	Ultra-Deep	High Gas	Heavy	Depleted/ Watery Oil	High Steam	High Flare	Extra-Heavy
Azerbaijan Azeri Light Kazakhstan Tengiz Norway Ekofisk Nigeria Agbami	Kuwait Ratawi Canada Hibernia Angola Girassol Iraq Zubair	Russia Chayvo Brazil Lula U.S. Gulf Mars U.S. Gulf Thunder Horse	U.S. Alaska North Slope	Angola Kuito Brazil Frade	UK Brent U.S. California South Belridge U.S. California Wilmington UK Forties Canada Midale	Indonesia Duri U.S. California Midway Sunset	China Bozhong Nigeria Obagi Nigeria Bonny	Canada Suncor Synthetic H (SCO) Canada Suncor Synthetic A (SCO) Canada Syncrude Synthetic (SCO) Canada Cold Lake (Dilbit) Venezuela Hamaca

THINK BEFORE BUILDING INFRASTRUCTURE

Because infrastructure lasts for generations, has opportunity costs, and has significant public impacts—as demonstrated by the debate over pipelines and refinery expansions—crudes should be compared before massive private investments are made in developing the increasingly diverse array of oil resources. It will also be important to analyze OCI impacts alongside shifting oil costs. Oil investments and their climate impacts need to be disaggregated by region, by oil, and throughout the oil supply chain.

To facilitate smart investment, stakeholders should improve the monitoring and reporting of oil capital expenditures in line with the OCI analysis as they relate to the GHG emissions expected for individual oil plays.

EXPLORE OPPORTUNITIES FOR GHG EMISSION REDUCTION

The GHG emissions from the 30 test oils run in OCI Phase 1 have a production-weighted average of 570 kilograms CO_2 equivalent per barrel oil. Emissions range from 450 to 820 kilograms CO_2 equivalent per barrel—nearly a difference of a factor of two in their climate intensity.

This wide range in GHG emissions opens the door for reducing the climate footprint of global oils. This could include extending current federal regulatory requirements for Environmental Impact Statements—documents prepared to describe the effects of proposed activities on the environment—to report oil assays and other OCI-relevant data during oil exploration. Low-emission oils could be slated for new development before high-GHG oils. There could be permit conditions placed on existing oil operations that bring high-GHG-emitting oils in line with average emitters. And employing best practices to improve operations, such as banning venting and nonemergency flaring, could reduce GHG emissions from existing oil supply chains.

Regulators and governments worldwide need to focus more on best practices to encourage producers, refiners, and traders to reduce greenhouse gases from high-emissions operations.

Upstream emissions—from exploration to production to oil transport to refining—have the greatest variability in their GHG emissions depending on venting, flaring, heat, and steam processing inputs. On the one hand, high-gas oils require infrastructure and operational expertise so they do not vent or flare their associated gas. On the other, oils that require significant heat and steam require more sophisticated methods to generate lower GHG inputs, such as co-generation, solar heat, and other techniques.

Regulators and governments worldwide need to focus more on best practices to encourage producers, refiners, and traders to reduce greenhouse gases from high-emissions operations. Different equipment, better handling, and improved management techniques will need to be employed over time to reduce GHG emissions.

Investors who choose to finance energy projects need to know what oils they are investing in. They should use their leverage to bring oil assays and other OCI-relevant oil data into the public domain and defer backing the development of high-GHG oils until technology is available or policies are adopted to reduce their climate footprints.

RECONCILE OIL ECONOMICS WITH GHG EMISSIONS

Oils' relative GHG emissions are not a major factor in the market price of crude oil, oil production costs, or the market value of the petroleum product slate from a given barrel of crude. Some crude oils with high GHG emissions, such as oil sands, are more expensive to produce, while others, such as high-GHG extra-heavy oils, are less expensive to produce. Still others, such as offshore U.S. Gulf of Mexico oil, have highly variable production costs but are not as GHG emission intensive.

While it is difficult to access oil cost data, the limited or weak relationship between an oil's GHG emissions and its production cost factors used by Rystad Energy can be demonstrated (see figure 16). Comparing Rystad's production cost curve to the OCI GHG emission supply curve shows that production costs identified by industry oil categories do not align with social costs imposed by GHG emissions. Greater oil price transparency is necessary to fully assess the relationship between GHG emissions and oil prices.

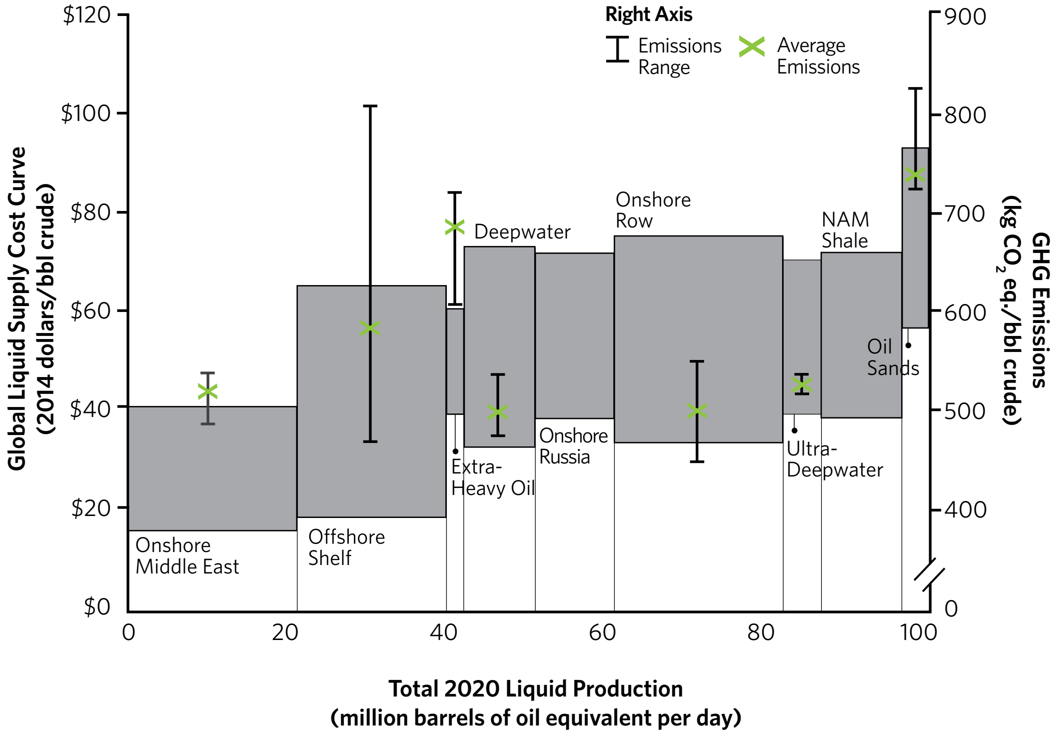
Oil's economic and environmental performance may, in fact, trend in the wrong direction: the more valuable the product yield, the higher the oil's GHG emissions (see figure 17).

Climate policy must take into account the total GHG footprint of the oil supply chain. Otherwise, market forces will continue to override climate concerns.

Addressing this issue requires designing public policies (especially regulatory requirements for oil assays and OCI-related data that are needed to design carbon taxes and other policy mechanisms) to differentiate between global oils. Comprehensive upstream, midstream, and downstream emissions must be factored into climate policies—both current implicit shadow prices used by industry and investors and future explicit carbon taxes and other policies.

FIGURE 16

Oil Supply Cost Curve With GHG Emission Ranges for 30 Phase 1 OCI Test Oils



Sources: Rystad Energy (supply cost curve), authors' calculations (GHG emission ranges)

Note: The 30 Phase 1 OCI test oils did not contain any onshore Russian or North American (NAM) shale oils. If data permits, these oils will be added in OCI Phase 2 results.

EXPAND THE OCI MODELS

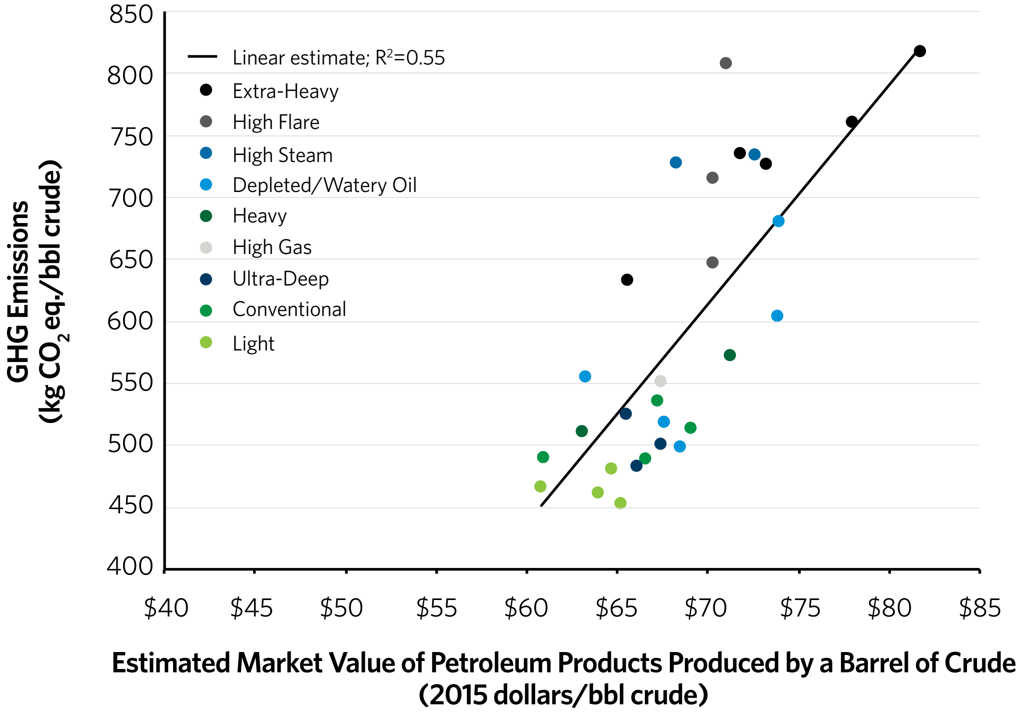
The 30 test oils modeled in the Oil-Climate Index account for approximately 4.5 million barrels per day of production, or 5 percent of global output. Hundreds more oils remain to be evaluated.

In order to accurately compare oils, both those in current production and those poised for future production, the index must be expanded to include a greater number, array, and volume of global oils. It would also allow further analysis of oil types, emission ranges within oil categories, exploration of new oil categories, and identification of outliers.

This expansion begins with the underlying models. Their upgrade requires improved oil data collection (discussed more in the appendix), which in turn will lead to updating and fine-tuning OCI input models. Including more global oils and accounting for new upstream, midstream, and downstream operations are central to the OCI effort.

FIGURE 17

Market Value Versus GHG Emissions for 30 Phase 1 OCI Test Oils



Source: Authors' calculations

Note: Petcoke prices are from 2014; all other prices are from 2015.

Update OPGEE

Model verification needs to continue, which involves conducting tests with process simulation software. Real-world cases with operating data could still be used. In addition, an improved flaring analysis that more accurately uses global satellite flaring databases should be integrated because flaring is responsible for high GHG emissions from some gassy oils but not others. Real-time satellite data can determine which oils are flared and how much they are flared; this information is necessary to regulate and monitor these emissions. Flaring GHG emissions must be expanded beyond carbon dioxide to include black carbon formation and the treatment of fugitive methane emissions, which are often unintended and not adequately modeled.

Expand PRELIM

PRELIM will need to be updated and expanded to include a float case, crude blending, and hydrogen surplus credits from lighter oils. A more detailed assessment of refinery fuel gas, asphalt, and bunker fuel needs to be undertaken. Statistical analysis of actual refinery operations will be necessary to explore variability and uncertainty in order to further update the PRELIM model.

Update OPEM

Product flows must be further disaggregated to track actual refinery outputs and create smart defaults for transport emissions. Improved harmonization between oils and refineries must be built into these models. The refinery selected by OPGEE for a particular oil needs to align with the starting point of petroleum product transport in OPEM. Opportunities for policies and best practices should be explored to reduce GHG emission impacts from downstream transport and other oil uses.

BUILD OUT THE OCI WEB TOOL

A user-friendly OCI web tool has been developed by a team at the Carnegie Endowment for International Peace to inform stakeholders about the results of the modeling of the 30 test oils. The tool permits novice and experienced users alike to explore the index, inputting user-defined data or manipulating the underlying models themselves. In subsequent versions, new oils will be added to the web tool along with the updates to OPGEE, PRELIM, and OPEM detailed above.

This tool should be used to evaluate policies currently in force or under continued development, including oil emission intensity standards (for example, California's Low Carbon Fuel Standard Program and the European Union's Fuel Quality Directive). It can also be used to develop best practices (oil production and refinery operating decisions) and advance more targeted identification of high-GHG oils throughout the supply chain.

ADDRESSING TOMORROW'S OIL-CLIMATE CHALLENGES

DESPITE JOHN D. ROCKEFELLER'S successful corporate marketing, there is no standard oil. Likewise, there is no single GHG emission calculus that applies to oils overall. Tracing a GHG emissions supply curve that plots the 30 OCI test oils in terms of their current production volumes and GHG emissions shows how disaggregated oils are in terms of their climate impacts (see figure 18).

Throughout the twentieth century, conventional oils were more plentiful and homogeneous than today's unconventional resources. The technological capacity now exists to turn coal and natural gas into liquid petroleum products—in fact, some in China, Qatar, and elsewhere are already doing this. Plastics can be converted back into oil. Extreme heat can be used to accelerate geologic time and turn kerogen, deposited naturally in rocks, into diesel fuel. Abundant methane hydrate supplies—natural gas crystals frozen in the world's oceans and elsewhere—may someday be tapped and then transformed into liquid fuels.

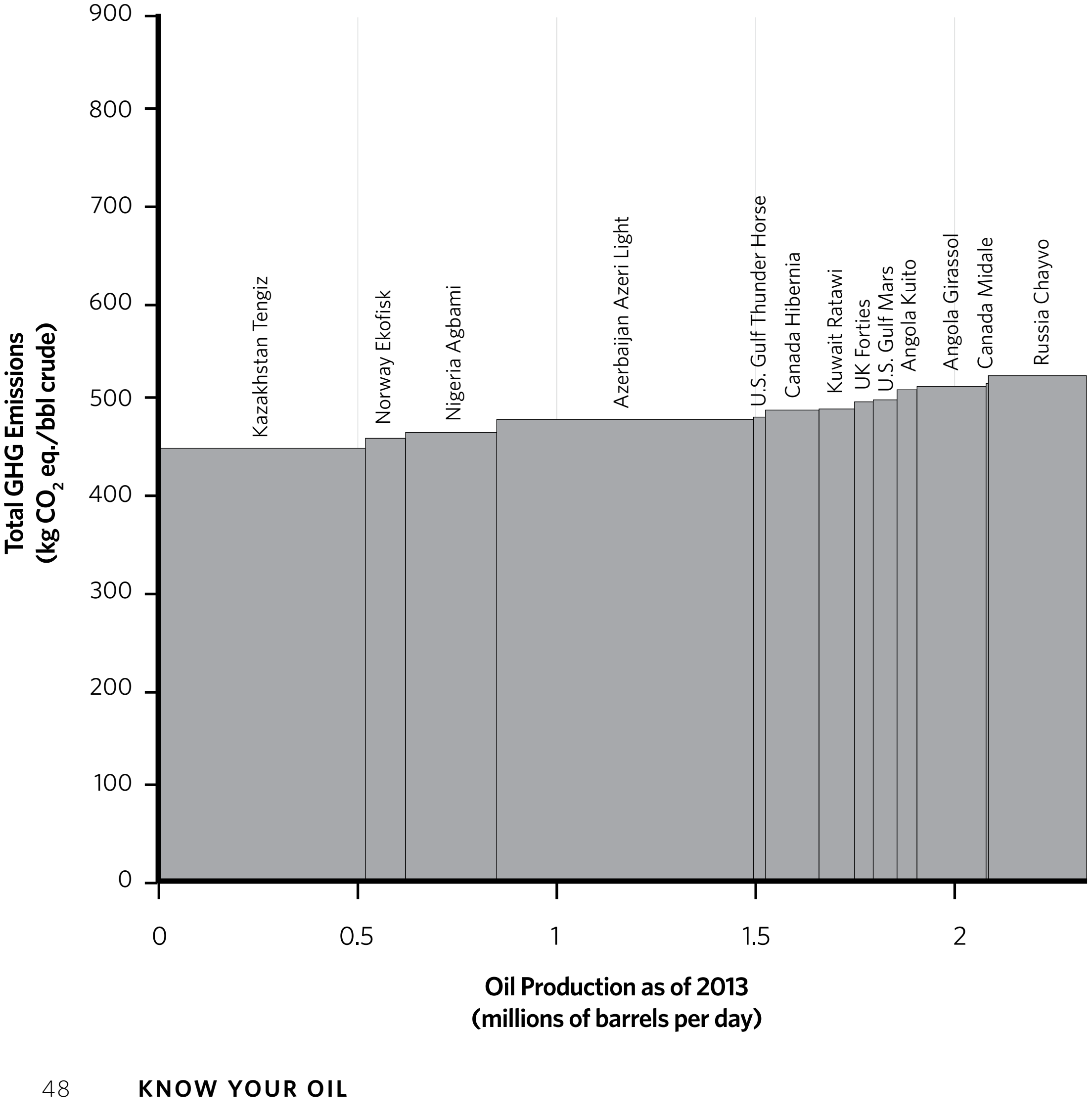
With technology evolving to tap and transform diverse hydrocarbons into liquid oil resources, the oil business has expanded and greatly diversified. It now encompasses international oil companies, independent oil operators, national oil companies, traders, oligarchs, totalitarian regimes, and all governments across the world.

These advances will bring new opportunities and challenges. Reimagined enhanced oil recovery techniques that inject gases and liquids of all sorts will unearth heavier and more depleted oils. Refining innovations will change petroleum products and yield new oil co-products. Expanding refining capacity in China, Nigeria, Saudi Arabia, Singapore, and elsewhere will continue to shift product transport worldwide. Traders will increase their stake in the oil supply chain to benefit from arbitrage amid future oil market volatility.

Meanwhile, in the twentieth century, climate change was not fully recognized as the major global threat it has since become. But global warming is now undeniably a matter of public record.

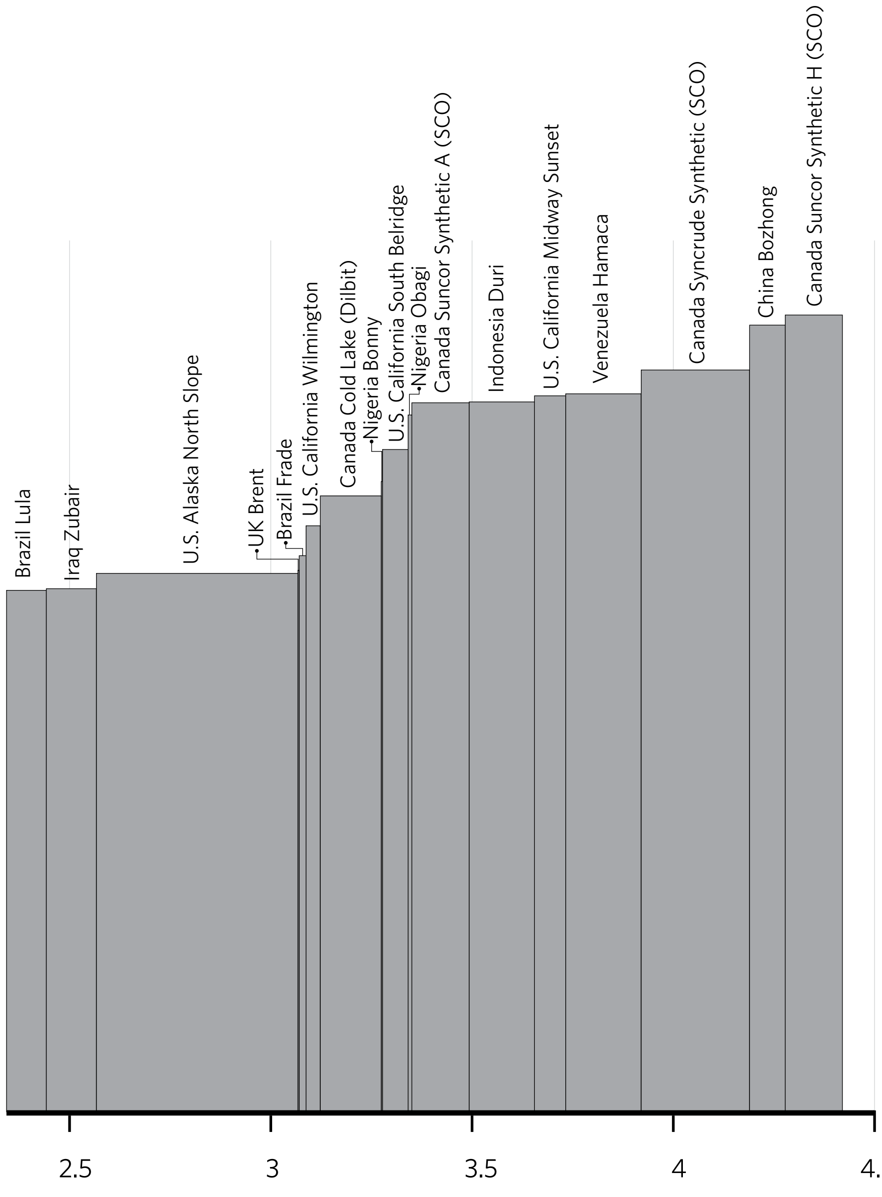
FIGURE 18

Oil-Climate Index Emissions Supply Curve for 30 Phase 1 OCI Test Oils



Tomorrow, oils will compete fiercely against other oils for market share in a warming world. In fact, this struggle has already begun. Oil markets are reeling as supplies are maintained in the face of softening global demand, and the Organization of the Petroleum Exporting Countries (OPEC) and North America (the United States, Canada, and Mexico) each expect the other to cut back production.

The progression from simpler to more complex oil value chains calls for more information, smarter decisionmaking, and sound policy guidance. The Oil-Climate Index offers



Source: Authors' calculations

Note: Unlike the other OCI test oils, Cold Lake dilbit is not composed of a full barrel of oil.

the means to comprehensively compare oils so climate impacts can be factored into financing, development, operating, and government oversight decisions. All stakeholders need better information about the GHG emissions embodied in the oil supply chain in order to avoid unintended climate consequences.

All stakeholders need better information about the GHG emissions embodied in the oil supply chain in order to avoid unintended climate consequences.

The large divergence in the climate impacts of global oils underscores the need to pick and choose wisely among resource options. End-use strategies that reduce the combustion of petroleum products—such as improved vehicle fuel efficiency, greater use of alternative fuels, and new mobility options—will no doubt be critical. But demand-side strategies, while necessary, are not sufficient. Oil supply-side strategies must contribute to the solution set as well.

Investors and industry need to make durable asset valuations and infrastructure decisions that will not be stranded by future climate policies and outcomes. Policymakers need up-to-date knowledge to approve permits, set standards, price carbon, and adopt better governance practices overall. And the public needs robust open-source information about oil to better understand the trade-offs between global oils in order to make wise energy choices.

The Oil-Climate Index can shape how consumers and industry approach future oil production and can guide the policies used to address oil-climate concerns. The first phase of the index highlights the large variation in GHG emissions between global oils. Incorporating the index into private and public decisionmaking and expanding this tool to account for a greater share of global oils are critical to reducing the climate impacts of the oil sector.

APPENDIX: OIL DATA GAPS

OIL MARKETS CANNOT function efficiently without transparent, high-quality information. Comprehensive information is also a necessary condition for effective policymaking. Oils' inherent chemical characteristics, their operational specifications, and how they differ from one another under varying sets of conditions are critical informational inputs.

In seeking to obtain and verify these needed oil data, several obstacles have been encountered:

- Oil data inconsistencies: There are hundreds of different global oils and no standardized format for oil assays. This makes it virtually impossible to compare oils.
- Data cannot be used without companies' permission: The oil industry publishes assays, and the fine print can present problems. For example, users who wish to comply with companies' policies have to obtain permission to reproduce oil data in any format. Therefore, some of the oil data that is available for viewing is not truly "open source" in practice.
- Data is not for sale: Up-to-date, comprehensive oil databases are held by the private sector, often oil consultancies. The price to obtain oil data is typically very high. But even if think tanks and academics can afford the hundreds of thousands of dollars to purchase oil data, it is not necessarily for sale. For example, after lengthy negotiations, a firm would not sell oil data even to academic scholars who were viewed as competitors.

- Government limitations to collecting data: The U.S. Department of Energy is limited in its reach to expand oil-reporting requirements. For example, one of the authors was told that the department could not establish consistent reporting requirements for oil data because the U.S. Office of Management and Budget considers oil data collection a duplication of effort from a budgetary perspective. This means that policymakers and the public are at the behest of industry to divulge information that may not be timely, accurate, or consistent.

Publicly available information, at a minimum, must contain expanded data collection as summarized in the figure below.

Open Source Oil-Climate Modeling

OPGEE *(Oil Production Greenhouse Gas Emissions Estimator)*

Upstream Production Data

1. Extraction method specifications *(primary, secondary, EOR, other)*
2. Level of activity per unit production
    - Water-to-oil ratio *(for primary and secondary production)*
    - Steam-to-oil ratio *(for tertiary production)*
3. Location *(onshore, offshore, with GIS coordinates)*
4. Flaring rate
5. Venting rate *(level of fugitive emissions)*

PRELIM *(Petroleum Refinery Life-Cycle Inventory Model)*

Midstream Refining Data

1. Reporting on updated refinery process energy requirement data
2. Refinery changes that affect petroleum product specifications and quality *(especially for bottom- and top-of-the-barrel products that are not regulated for use in vehicle engines)*
3. Oil assay parameters (specified below) and reported consistently for each global oil

Each parameter (except MCR/CCR) must be specified at each cut temperature, and cut temperature ranges must be standardized, as specified below or in another consistent format.

Note: Cut temperatures are currently reported out using a variety of inconsistent formats.

- API Gravity
- Density
- Sulfur content (wt %)
- Nitrogen content (mass ppm)
- Hydrogen content
- Volume/Mass Flow (% recovery)
- Micro-carbon residue (MCR) or Conradson carbon residue (CCR)
- Viscosity (cST at 100 °C) for Vacuum Residuum

*The cut temperatures and products currently used in the PRELIM refining model are:

Temperature	Product Cut Name
80 °C	Light Straight Run
180 °C	Naphtha
290 °C	Kerosene
343 °C	Diesel
399 °C	Atmospheric Gas Oil (AGO)
454 °C	Light Vacuum Gas Oil (LVGO)
525 °C	Heavy Vacuum Gas Oil (HVGO)
525+ °C	Vacuum Residue (VR)
399+ °C	Atmospheric Residue (AR)

OPEM *(Oil Products Emissions Module)*
Downstream Transport and Combustion Data

1. Global oil trade statistics
   (by crude, product, mode, and region)
2. Annual mapping of changing trade patterns and trends
   (disaggregated by the full spectrum of petroleum products)
3. Domestic (in-country) oil and petroleum product transfers
   (GIS coordinates from refinery gate or shipping hub to end use)
4 Origin data (crudes) and destination data (individual petroleum products), by refinery
5. Market prices for all oil products
   (petrochemical feedstocks, condensates, petroleum coke (petcoke), bunker fuel, fuel oil #4, asphalt, and other marketable refined products)

NOTES

1 Christophe McGlade and Paul Ekins, "The Geographical Distribution of Fossil Fuels Unused When Limiting Global Warming to 2 °C," *Nature* 517, no. 7533 (2015): 187–90, http://dx.doi.org/10.1038/nature14016.

2 Jonathan Koomey, "Moving Beyond Benefit-Cost Analysis of Climate Change," *Environmental Research Letters* 8, no. 041005, December 2, 2013, http://iopscience.iop.org/1748-9326/8/4/041005; Malte Meinshausen, Nicolai Meinshausen, William Hare, Sarah C. B. Raper, Katja Frieler, Reto Knutti, David J. Frame, and Myles R. Allen, "Greenhouse-Gas Emission Targets for Limiting Global Warming to 2 Degrees C," *Nature* 458 (April 30, 2009): 1158–62, www.nature.com/nature/journal/v458/n7242/full/nature08017.html; University College of London, "Which Fossil Fuels Must Remain in the Ground to Limit Global Warming?" January 7, 2015, www.ucl.ac.uk/news/news-articles/0115/070115-fossil-fuels; http://unfccc.int/resource/docs/2009/cop15/eng/l07.pdf.

3 OPGEE was developed by Hassan El-Houjeiri, Kourosh Vafi, Scott McNally, and Adam Brandt at Stanford University. Significant assistance was provided by James Duffy of the California Air Resources Board. The State of California adopted OPGEE, the first open-source GHG emissions tool for oil and gas operations, through rulemaking for the development of California's Low Carbon Fuel Standard in November 2012. New OPGEE versions have since been released. The version of OPGEE used in generating this report is OPGEE version 1.1 draft D. For the OPGEE User Guide and Technical Documentation see https://pangea.stanford.edu/researchgroups/eao/research/opgee-oil-production-greenhouse-gas-emissions-estimator.

4 PRELIM was developed by Jessica Abella, Kavan Motazedi, and Joule Bergerson at the University of Calgary. The following individuals and institutions have been involved in the development of the open-source PRELIM model: researchers on the LCAOST project including Professor Heather MacLean; Natural Resources Canada; Alberta Innovates: Energy and Environment Solutions; Carbon Management Canada; National Science and Engineering Research Council of Canada; Carnegie Endowment for International Peace; LCAOST Oil Sands Industry Consortium. For PRELIM User Guide and Technical Documentation see http://ucalgary.ca/lcaost/PRELIM.

5 "Worldwide Refineries—Capacities as of Jan. 1, 2014," *Oil & Gas Journal*, December 31, 2014.

6 Emissions are calculated according to the displacement of like products by energy value. Any natural gas produced and then exported off-site is assumed to displace average natural gas emissions calculated in the GREET (Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation) model. Any electricity generated on-site displaces GREET natural gas-based electric power.

7 See the following papers for analysis of OPGEE estimate improvement with increasing data availability: A. R. Brandt, Y. Sun, and K. Vafi, "Uncertainty in Regional-Average Petroleum GHG Intensities: Countering Information Gaps With Targeted Data Gathering," *Environmental Science & Technology*, DOI: 10.1021/es505376t, 2014; K. Vafi, A. R. Brandt, "Uncertainty of Oil Field GHG Emissions Resulting From Information Gaps: A Monte Carlo Approach," *Environmental Science & Technology*, DOI: 10.1021/es502107s, 2014.

8 The "fixed" case, where the volumes of final products are set and the amount of input crude varies to provide the final product slate, is currently in development. The "fixed" case will be capable of either fixing the gasoline to diesel ratio or a specific set of final product volumes.

9 Jessica P. Abella and Joule A. Bergerson, "Model to Investigate Energy and Greenhouse Gas Emissions Implications of Refining Petroleum: Impacts of Crude Quality and Refinery Configuration," *Environmental Science & Technology* 46, no. 24 (2012): 13037–13047, DOI: 10.1021/es3018682, http://pubs.acs.org/doi/abs/10.1021/es3018682.

10 Incomplete assays containing as few as four fractions and high-temperature simulated distillation (HTSD) curves can be put into PRELIM, but this introduces uncertainty that can affect emission outputs.

11 Pioneers in this field include: Argonne National Laboratory GREET Lifecycle Model (Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation Model), https://greet.es.anl.gov; Lifecycle Associates, www.lifecycleassociates.com; Natural Resources Canada GHGenius Model, www.ghgenius.ca; International Council on Clean Transportation, www.theicct.org/info/assets/RoadmapV1/ICCT%20Roadmap%20Model%20Version%201-0%20Documentation.pdf; Jacobs Consultancy, http://eipa.alberta.ca/media/39640/life%20cycle%20analysis%20jacobs%20final%20report.pdf; and others.

12 GREET 1 2013, sheet "EF," Table 2.3, "Emission Factors of Fuel Combustion: Feedstock and Fuel Transportation From Product Origin to Product Destination Back to Product Origin (Grams per mmBtu of Fuel Burned)," Energy Intensities were taken from GREET 1 2014 on the properties page "Step Parameters" for each mode of transport, respectively.

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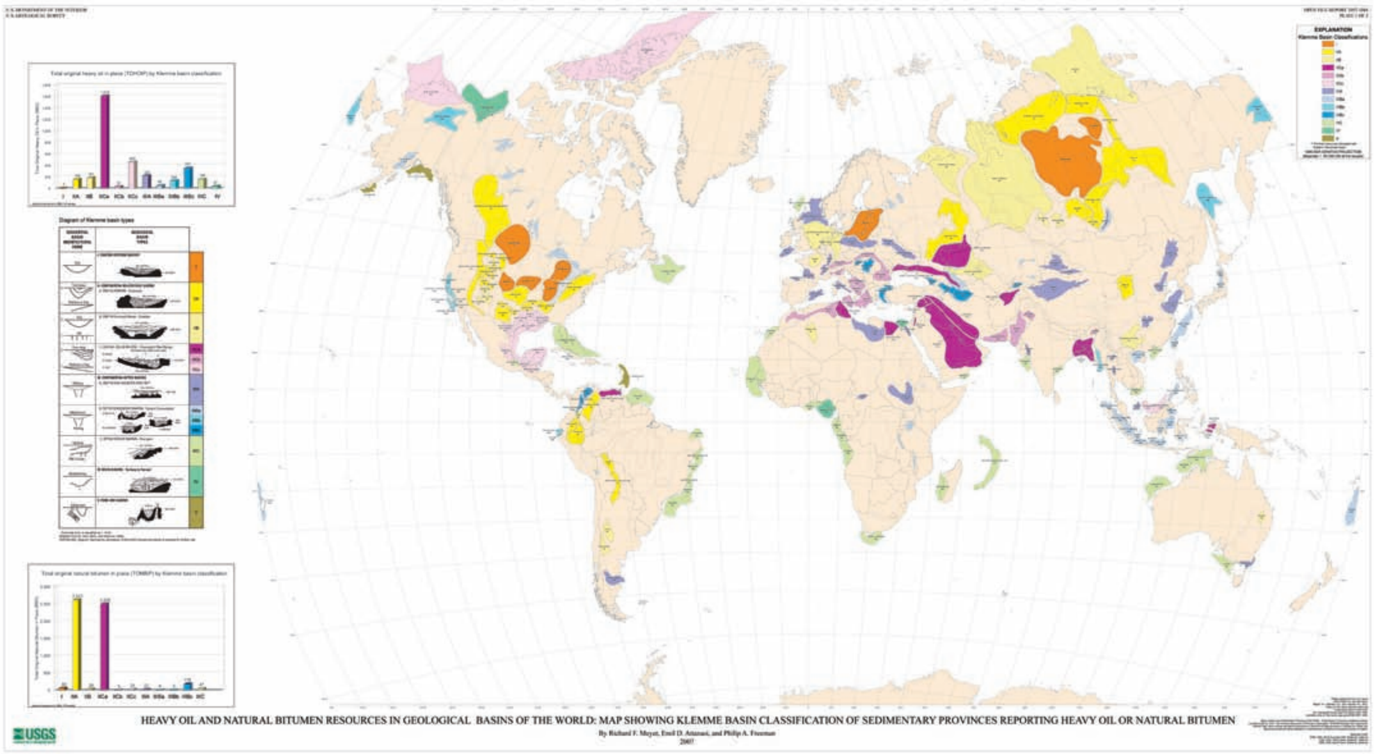
Heavy Oil and Natural Bitumen Resources in Geological Basins of the World



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By Richard F. Meyer, Emil D. Attanasi, and Philip A. Freeman

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Heavy Oil and Natural Bitumen Resources in Geological Basins of the World

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Abstract

Heavy oil and natural bitumen are oils set apart by their high viscosity (resistance to flow) and high density (low API gravity). These attributes reflect the invariable presence of up to 50 weight percent asphaltenes, very high molecular weight hydrocarbon molecules incorporating many heteroatoms in their lattices. Almost all heavy oil and natural bitumen are alteration products of conventional oil. Total resources of heavy oil in known accumulations are 3,396 billion barrels of original oil in place, of which 30 billion barrels are included as prospective additional oil. The total natural bitumen resource in known accumulations amounts to 5,505 billion barrels of oil originally in place, which includes 993 billion barrels as prospective additional oil. This resource is distributed in 192 basins containing heavy oil and 89 basins with natural bitumen. Of the nine basic Klemme basin types, some with subdivisions, the most prolific by far for known heavy oil and natural bitumen volumes are continental multicyclic basins, either basins on the craton margin or closed basins along convergent plate margins. The former includes 47 percent of the natural bitumen, the latter 47 percent of the heavy oil and 46 percent of the natural bitumen. Little if any heavy oil occurs in fore-arc basins, and natural bitumen does not occur in either fore-arc or delta basins.

Introduction

Until recent years conventional, light crude oil has been abundantly available and has easily met world demand for this form of energy. By year 2007, however, demand for crude oil worldwide has substantially increased, straining the supply of conventional oil. This has led to consideration of alternative or insufficiently utilized energy sources, among which heavy crude oil and natural bitumen are perhaps the most readily available to supplement short- and long-term needs. Heavy oil has long been exploited as a source of refinery feedstock, but has commanded lower prices because of its lower quality relative to conventional oil. Natural bitumen is a very viscous crude oil that may be immobile in the reservoir. It typically requires upgrading to refinery feedstock grade (quality). When natural bitumen is mobile in the reservoir, it is generally known as extra-heavy oil. As natural asphalt, bitumen has been exploited since antiquity as a source of road paving, caulk, and mortar and is still used for these purposes in some parts of the world. The direct use of mined asphalt for road paving is now almost entirely local, having been replaced by manufactured asphalt, which can be tailored to specific requirements.

This study shows the geological distribution of known heavy oil and natural bitumen volumes by basin type. These data are presented to advance a clearer understanding of the relationship between the occurrence of heavy oil and natural bitumen and the type of geological environment in which these commodities are found. The resource data presented were compiled from a variety of sources. The data should not be considered a survey of timely resource information such as data published annually by government agencies and public reporting services. With the exception of Canada, no such data source on heavy oil and natural bitumen accumulations is available. The amounts of heavy oil yet unexploited in known deposits represent a portion of future supply. To these amounts may be added the heavy oil in presently poorly known and entirely unexploited deposits. Available information indicates cumulative production accounts for less than 3 percent of the discovered heavy oil originally in place and less than 0.4 percent of the natural bitumen originally in place.

Terms Defined for this Report

- Conventional (light) Oil: Oil with API gravity greater than 25°.
- Medium Oil: Oil with API gravity greater than 20°API but less than or equal to 25°API.
- Heavy Oil: Oil with API gravity between 10°API and 20°API inclusive and a viscosity greater than 100 cP.
- Natural Bitumen: Oil whose API gravity is less than 10° and whose viscosity is commonly greater than 10,000 cP. It is not possible to define natural bitumen on the basis of viscosity alone because much of it, defined on the basis of gravity, is less viscous than 10,000 cP. In addition, viscosity is highly temperature-

dependent (fig. 1), so that it must be known whether it is measured in the reservoir or in the stock tank. In dealing with Russian resources the term natural bitumen is taken to include both maltha and asphalt but excludes asphaltite.

- Total Original Oil in Place (TOOIP): Both discovered and prospective additional oil originally in place.
- Original Oil in Place-Discovered (OOIP-Disc.): Discovered original oil in place.
- Reserves (R): Those amounts of oil commonly reported as reserves or probable reserves, generally with no further distinction, and quantities of petroleum that are anticipated to be technically but not necessarily commercially recoverable from known accumulations. Only in Canada are reserves reported separately as recoverable by primary or enhanced methods. Russian reserve classes A, B, and C1 are included here (See Grace, Caldwell, and Hether,1993, for an explanation of Russian definitions.)
- Prospective Additional Oil in Place: The amount of resource in an unmeasured section or portion of a known deposit believed to be present as a result of inference from geological and often geophysical study.
- Original Reserves (OR): Reserves plus cumulative production. This category includes oil that is frequently reported as estimated ultimately recoverable, particularly in the case of new discoveries.

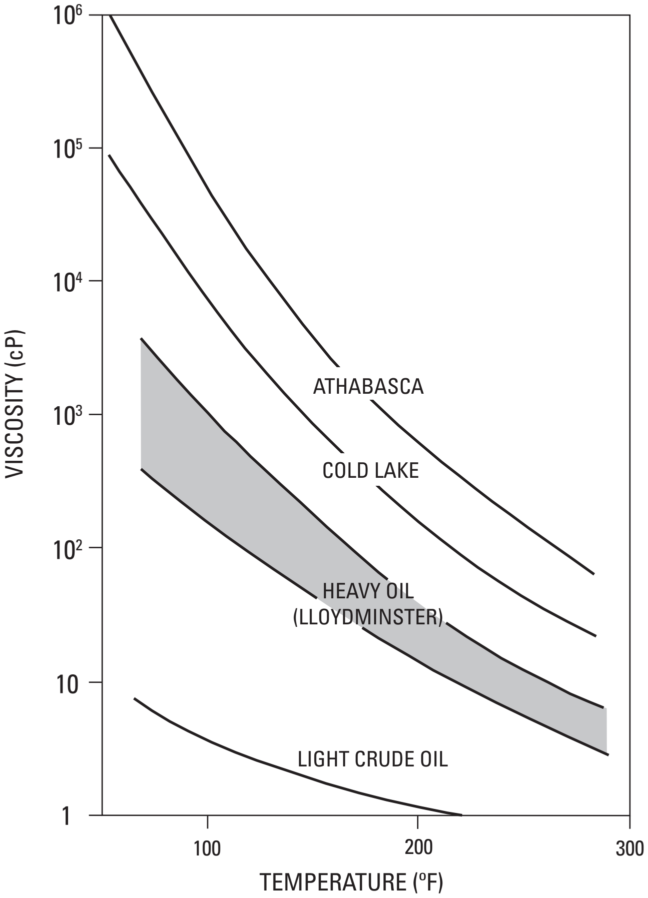

Figure 1. Response of viscosity to change in temperature for some Alberta oils (cP, centipoise), (Raicar and Proctor, 1984).

Chemical and Physical Properties

Fundamental differences exist between natural bitumen, heavy oil, medium oil, and conventional (light) oil, according to the volatilities of the constituent hydrocarbon fractions: paraffinic, naphthenic, and aromatic. When the light fractions are lost through natural processes after evolution from organic source materials, the oil becomes heavy, with a high proportion of asphaltic molecules, and with substitution in the carbon network of heteroatoms such as nitrogen, sulfur, and oxygen. Therefore, heavy oil, regardless of source, always contains the heavy fractions, the asphaltics, which consist of resins, asphaltenes, and preasphaltenes (the carbene-carboids) (Yen, 1984). No known heavy oil fails to incorporate asphaltenes. The large asphaltic molecules define the increase or decrease in the density and viscosity of the oil. Removal or reduction of asphaltene or preasphaltene drastically affects the rheological properties of a given oil and its aromaticity (Yen, 1984). Asphaltenes are defined formally as the crude oil fraction that precipitates upon addition of an n-alkane, usually n-pentane or n-heptane, but remains soluble in toluene or benzene. In the crude oil classification scheme of Tissot and Welte (1978), the aromatic-asphaltics and aromatic-naphthenics characterize the heavy oil and natural bitumen deposits of Canada and Venezuela and are the most important of all crude oil classes with respect to quantity of resources. The aromatic-intermediate class characterizes the deposits of the Middle East (Yen, 1984).

Some of the average chemical and physical properties of conventional, medium, and heavy crude oils and natural bitumen are given in table 1, in order to show their distinguishing characteristics. The data are derived from multiple sources, some old and others adhering to standards employed in different countries. The conversion factors outlined in table 2 were used to convert published data to a uniform standard. Some of the properties in table 1 are important with respect to heavy oil and natural recovery from the ground and other properties in table 1 serve as the basis for decisions for upgrading and refinery technologies. Moving across table 1 from conventional oil to natural bitumen, increases may be seen in density (shown as reductions in API gravity), coke, asphalt, asphaltenes, asphaltenes + resins, residuum yield (percent volume), pour point, dynamic viscosity, and the content of copper, iron, nickel, vanadium among the metals and in nitrogen and sulfur among the non-metals. Values diminish for reservoir depth, gasoline and gas-oil yields, and volatile organic compounds (VOC and BTEX –Benzene, Toluene, Ethylbenzene, and

Xylenes). The significance of these differences is often reflected in the capital and operating expenses required for the recovery, transportation, product processing, and environmental mitigation of the four oil types. The principal sources of analytical data for table 1 are Environmental Technology Centre (2003), Hyden (1961), Oil & Gas Journal Guide to Export Crudes (2006), U.S. Department of Energy, National Energy Technology Laboratory (1995), and various analyses published in technical reports.

The resins and asphaltenes play an important role in the accumulation, recovery, processing, and utilization of petroleum. The resins and asphaltenes are the final form of naphtheno-aromatic molecules. The carbon skeleton appears to comprise three to five polyaromatic sheets, with some heterocyclic (N-S-O) compounds. These crystallites may combine to form high molecular weight aggregates, with the high viscosity of heavy oils related to the size and abundance of the aggregates. Most asphaltenes are generated from kerogen evolution in response to depth and temperature increases in sedimentary basins. Different types of asphaltenes may be derived from the main kerogen types. Asphaltenes are not preferentially mobilized, as are light hydrocarbons during migration from source rocks to reservoir beds, where they are less abundant if the crude oil is not degraded (Tissot, 1981).

Some heavy oil and natural bitumen originates with chemical and physical attributes shown in table 1 as immature oil which has undergone little if any secondary migration. The greatest amount of heavy oil and natural bitumen results from the bacterial degradation under aerobic conditions of originally light crude oils at depths of about 5,000 feet or less and temperatures below 176°F. The consequence of biodegradation is the loss of most of the low molecular weight volatile paraffins and naphthenes, resulting in a crude oil that is very dense, highly viscous, black or dark brown, and asphaltic. An active water supply is required to carry the bacteria, inorganic nutrients, and oxygen to the oil reservoir, and to remove toxic by-products, such as hydrogen sulfide, with low molecular weight hydrocarbons providing the food (Barker, 1979). The low molecular weight components also may be lost through water washing in the reservoir, thermal fractionation, and evaporation when the reservoir is breached at the earth's surface (Barker, 1979). The importance of this process to the exploitation of heavy oil and natural bitumen lies in the increase of NSO (nitrogen-sulfur-oxygen) compounds in bacterially-altered crude oil and the increase in asphaltenes (Kallio, 1984).

Bacterial degradation of crude oil may also take place under anaerobic conditions, thus obviating the need for a fresh water supply at shallow depths (Head, Jones, and Larter, 2003; Larter and others, 2006). This proposal envisions degradation even of light oils at great depths so long as the maximum limiting temperature for bacterial survival is not exceeded. This theory does not account in any obvious way for the high percentage in heavy oil and natural bitumen of polar asphaltics, that is, the resins and asphaltenes.

Oil mass loss entailed in the formation of heavy oil and natural bitumen deposits has been the subject of numerous research studies. Beskrovnyi and others (1975) concluded that three to four times more petroleum was required than the reserves of a natural bitumen for a given deposit. Based upon material balance calculations in the Dead Sea basin, Tannenbaum, Starinsky, and Aizenshtat (1987) found indications that 75% of the original oil constituents in the C15+ range had been removed as a result of alteration processes. By accounting for the lower carbon numbers as well, they estimated that the surface asphalts represented residues of only 10-20% of the original oils. Head, Jones, and Larter (2003) diagram mass loss increasing from essentially zero for conventional oil to something more than 50% for heavy oils, which of themselves are subject to no more than 20% loss. Accompanying the mass loss is a decrease in API gravity from 36° to 5-20°; decrease in gas/oil ratio from 0.17 kg gas/kg oil; decrease in gas liquids from 20% to 2%; increase in sulfur from 0.3wt% to 1.5+wt%; and decrease in C15+ saturates from 75% to 35%. This calculation of mass loss shows: (1) the enormous amount of oil initially generated in heavy oil and natural bitumen basins, especially Western Canada Sedimentary and Eastern Venezuela basins; and (2) the huge economic burden imposed by this mass loss on the production-transportation-processing train of the remaining heavy oil and natural bitumen.

Origins of Heavy Oil and Natural Bitumen

It is possible to form heavy oil and natural bitumen by several processes. First, the oil may be expelled from its source rock as immature oil. There is general agreement that immature oils account for a small percentage of the heavy oil (Larter and others, 2006). Most heavy oil and natural bitumen is thought to be expelled from source rocks as light or medium oil and subsequently migrated to a trap. If the trap is later elevated into an oxidizing zone, several processes can convert the oil to heavy oil. These processes include water washing, bacterial degradation and evaporation. In this case, the biodegradation is aerobic. A third proposal is that biodegradation can also occur at depth in subsurface reservoirs (Head, Jones, and Larter, 2003; Larter and others, 2003; Larter and others, 2006). This explanation permits biodegradation to occur in any reservoir that has a water leg and has not been heated to more than 176° F. The controls on the biodegradation depend on local factors rather than basin-wide factors. Because the purpose of this report is to describe the geologic basin setting of the known heavy oil and natural bitumen deposits, it is beyond the scope of this report to argue the source or genesis of heavy oil and natural bitumen for each basin of the world.

Data Sources

Data for heavy oil resource occurrences and quantities for individual oilfields and reservoirs have been compiled from many published reports and commercial data bases. The most important of these include Demaison (1977), IHS Energy Group (2004), NRG Associates (1997), Parsons (1973), Roadifer (1987), Rühl (1982), and the U.S. Department of Energy, National Energy Technology Laboratory (1983, 2005)

Data for natural bitumen deposits in the United States are summarized in U.S Department of Energy, National Energy Technology Laboratory (1991), but information for Utah is taken from Oblad and others (1987) and Ritzma (1979). Although there is no single data source for deposits outside the United States, there is a rich literature, particularly for Russia and the countries of the Former Soviet Union. For Canada, reliance is placed on reports of the Alberta Energy and Utilities Board (2004) and Saskatchewan Industry and Resources (2003).

Resource Estimates

We consider the total original oil in place (OOIP) to be the most useful parameter for describing the location and volume of heavy oil and natural bitumen resources. Resource quantities reported here are based upon a detailed review of the literature in conjunction with available databases, and are intended to suggest, rather than define the resource volumes that could someday be of commercial interest. If only a recoverable volume of heavy oil for the accumulation was published, the discovered OOIP was computed according to the protocol set forth in table 3.

Natural bitumen originally in place is often reported in the literature. Where only a recoverable estimate is published, the in-place volumes were calculated according to the protocols given for heavy oil; this is especially the case for bitumen deposits above 4°API gravity, to which we arbitrarily refer as extra-heavy oil.

Poorly known deposits of heavy oil and natural bitumen are included in the category of prospective additional resources, as described in table 3. In no case are values for prospective additional resource volumes calculated as in the case of discovered resources but were taken directly from the published literature.

Table 4 summarizes the resources and essential physical parameters of the heavy oil and natural bitumen contained in each of the basin types. These characteristics affect heavy oil and natural bitumen occurrence and recovery. Recovery can be primary, as in the case of cold production without gravel packing, if the gas to oil ratio is high enough to provide necessary reservoir energy. Otherwise, recovery generally necessitates the application of enhanced recovery methods, such as thermal energy or the injection of solvents.

Recovery Methods

How the reservoir parameters apply to enhanced recovery is summarized from Taber, Martin, and Seright (1997a, 1997b) in table 5, which covers the most commonly used, or at least attempted enhanced oil recovery (EOR) methods. Of these methods, immiscible gas injection, polymer flooding, and *in situ* combustion (fireflood) have met with limited success for heavy oil and natural bitumen. Steam injection (cyclic steam, huff ‘n puff) has been most successful, frequently by use of cyclic steam, followed by steam flooding. Surface mining and cold *in situ* production are usually considered to be primary recovery methods. They can be suited to the extraction of heavy oil and natural bitumen under proper conditions.

Most of the process descriptions which follow are taken from Taber, Martin, and Seright (1997b). Many processes may result in the process agent, such as nitrogen or carbon dioxide, remaining immiscible with the reservoir hydrocarbon or else becoming miscible with it. The miscibility is dependent upon the minimum miscibility pressure (MMP) and determines the way in which the process agent achieves EOR. While this summary discussion shows the breadth of the EOR processes operators have tried and continue to try as experimental projects, thermal EOR methods account for most of the heavy oil that is commercially produced. Data on the frequency of the applications are taken, unless otherwise cited, from the Oil and Gas Journal Historical Review, 1980-2006 (2006), particularly the Oil and Gas Journal 2000 and 2006 EOR Surveys.

Nitrogen gas drive is low in cost and therefore may be used in large amounts. It is commonly used with light oils for miscible recovery. However, it may also be used for an immiscible gas flood. The Oil and Gas Journal 2000 Survey includes one immiscible nitrogen gas drive in a sandstone reservoir with 16˚API oil at 4,600 feet depth. It was reported to be producing 1,000 barrels per day (b/d) of enhanced production. The Journal’s 2006 Survey reports one each heavy oil nitrogen miscible and nitrogen immiscible projects. The miscible project is 19˚API, located in the Bay of Campeche, with 19 wells, but with no report of production capacity. The immiscible project has oil of 16˚API at 4,600 feet in sandstone. For this project total production is reported to be 1,500 b/d of which 1,000 b/d is enhanced by immiscible nitrogen injection.

Of the 77 CO2 projects in the Journal 2000 Survey, 70 are for miscible CO2 and none entails heavy oil. This is true also in the Journal 2006 Survey, where all 86 CO2 projects are devoted to light oil, above 28˚API. In the Journal 2000 Survey, five of the seven immiscible CO2 projects are applied to heavy oil reservoirs, four in clastics and one in limestone. The latter, in the West Raman field in Turkey, involves oil of 13°API, lies at 4,265 feet, and produces 8,000 b/d. The reservoir contains nearly two billion barrels of original oil in place. Recoverable reserves remain low because of the recalcitrance of the reservoir. Steam flooding has been unsuccessful. By the date of the Journal 2006, there are eight immiscible CO2 projects, with five of them entailing heavy oil amounting to 7,174 b/d. The two largest projects are light oil and heavy oil and are each in carbonate reservoirs.

Polymer/chemical flooding includes micellar/polymer, alkaline-surfactant-polymer (ASP), and alkaline fluids (Taber, Martin, and Seright, 1997a, 1997b). Recovery is complex, leading to the lowering of interfacial tension between oil and water, solubilization of oil in some micellar systems, emulsification of oil and water, wettability alteration, and enhancement of mobility. Limitations and costs indicate for these floods the desirability of clean clastic formations. The Journal 2000 Survey shows five heavy oil polymer/chemical floods of 15°API in sandstone reservoirs at about 4,000 feet. They were producing about 366 b/d and the projects were deemed successful or promising. Projects such as these are below the desirable gravity limits and are more viscous than desired at 45 cP.

Polymer floods improve recovery over untreated water flood by increasing the viscosity of the water, decreasing thus the mobility of the water, and contacting a larger volume of the reservoir. The advantages of a polymer flood over a plain water flood are apparent. The Journal 2000 Survey lists 22 polymer flood projects, of which five involve heavy oil. These five are within the range of the polymer screen, although the gravities are marginal, lying from 13.5°API to a bit above 15°API. The five were producing 7,140 b/d, of which 2,120 b/d were attributed to EOR. The Journal 2006 Survey shows 20 polymer floods, with five exploring heavy oil reservoirs. Three of the five are producing 7,140 b/d total oil and 2,120 b/d of enhanced production.

The Journal 2000 Survey shows four hot water floods, one of which is heavy oil with a gravity of 12°API, viscosity of 900 cP, and starting saturation of only 15 percent. Project production was 300 b/d. Two of three hot water floods included in the Journal 2006 Survey are intended to enhance production of heavy oil. The two yield about 1,700 b/d of total oil and 1,700 b/d of enhanced hot water flood oil.

In situ combustion (fire flood) is theoretically simple, setting the reservoir oil on fire and sustaining the burn by the injection of air. Usually, the air is introduced through an injector well and the combustion front moves toward to the production wells. A variant is to include a water flood with the fire, the result being forward combustion with a water flood. Another variant is to begin a fire flood, then convert the initial well to a producer and inject air from adjacent wells. The problem with this reverse combustion is that it doesn't appear to work.

In situ combustion leads to oil recovery by the introduction of heat from the burning front, which leads to reduction in viscosity. Further, the products of steam distillation and thermal cracking of the reservoir oil are carried forward to upgrade the remaining oil. An advantage of the process is that the coke formed by the heat itself burns to supply heat. Lastly, the injected air adds to the reservoir pressure. The burning of the coke sustains the process so that the process would not work with light oil deficient in asphaltic components. The process entails a number of problems, some severe, but the Journal 2000 Survey shows 14 combustion projects, of which five are light oil and the remaining nine are heavy, between 13.5°API and 19°API. Viscosities and starting oil saturations are relatively high. It is notable that the heavy oil projects are in sandstones and the light oil in carbonates. The heavy oil *in situ* combustion projects were producing about 7,000 b/d. The Journal 2006 Survey includes nine heavy oil combustion projects among a total of twenty-one. The heavy oil projects yield about 7,000 b/d of combustion-enhanced oil, which ranges from 13.5˚API to 19˚API.

Steam injection for EOR recovery is done in two ways, either by cyclic steam injection (huff ‘n puff) or continuous steam flood. Projects are frequently begun as cyclic steam, whereby a high quality steam is injected and soaks the reservoir for a period, and the oil, with lowered viscosity from the heat, is then produced through the injection well. Such soak cycles may be repeated up to six times, following which a steam flood is initiated. In general, steam projects are best suited to clastic reservoirs at depths no greater than about 4,000 feet, and with reservoir thicknesses greater than 20 feet and oil saturations above 40% of pore volume. For reservoirs of greater depth the steam is lowered in quality through heat loss to the well bore to where the project becomes a hot water flood. Steam is seldom applied to carbonate reservoirs in large part due to heat loss in fractures.

The Journal 2000 Survey lists 172 steam drive projects. Of these, four in Canada give no gravity reading, thirteen are medium oil from 22°API to 25°API, and the rest are heavy oil. The largest of all is at Duri field in Indonesia and this oil is 22°API. For the project list as a whole, the average gravity is 14°API, with a maximum value of 30°API and a minimum of 4°API. The average viscosity is 37,500 cP, with maximum and minimum values of 5,000,000 cP and 6 cP. Oil saturations range from 35% to 90%, the average being 68%. Most importantly, production from the project areas was 1.4 million b/d and of this, 1.3 million b/d was from steam drive EOR.

All but three of the 120 steam projects found in the Journal 2006 Survey entail recovery of heavy oil. The oil averages 12.9˚API, with a low value of 8˚API and a high of 28˚API (one of the three light oil reservoirs). The viscosity averages 58,000 cP, with a high value of 5 million cP and a low of 2 cP. The projects are yielding over 1.3 million b/d, virtually all being steam EOR.

Maps

The geographic distribution of basins reporting heavy oil and natural bitumen, as identified by their Klemme basin types, appears on Plate 1. A diagram of the Klemme basin classification illustrates the architectural form and the geological basin structure by type. This plate also includes histograms of the total original oil in place resource volumes of both heavy oil and natural bitumen. Plates 2 and 3, respectively, depict the worldwide distribution of heavy oil and natural bitumen resources originally in place. Each map classifies basins by the reported volumes of total original oil in place. A table ranks the basins by total original oil in place volumes besides indicating Klemme basin type and reporting discovered original oil in place and prospective additional oil in place. Plates 2 and 3 also include an inset map of the geographic distribution of original heavy oil or natural bitumen by 10 world regions (see table 6 for regional listing of countries reporting heavy oil or natural bitumen.)

Basin outlines of the sedimentary provinces are digitally reproduced from the AAPG base map compiled by St. John (1996). The basin outlines of St. John (1996) are unaltered. However, the reader should note that the basin outlines are considered to be generalizations useful for displaying the resource distributions but are less than reliable as a regional mapping tool. Also, some basin names have been changed to names more commonly used by geologists in the local country. These equivalent names and the original names from Bally (1984) and St. John (1996) are detailed in table 1-1 in Appendix 1. The basin outline for Eastern Venezuela as shown does not include the island of Trinidad where both heavy oil and natural bitumen resources occur. For this report, resources from Trinidad and Tobago are reported in the Eastern Venezuela basin totals. In a few cases a single basin as outlined on the plates is composed of multiple basins to provide more meaningful local information. This is particularly true in the United States, where the AAPG-CSD map was employed (Meyer, Wallace, and Wagner, 1991). In each case, the individual basins retain the same basin type as the basin shown on the map and all such basins are identified in Appendix 1.

Basins having heavy oil or natural bitumen deposits are listed in table 2-1 in Appendix 2 along with the Klemme basin type, countries and U.S. states or Canadian provinces reporting deposits and other names cited in literature. The Klemme basin classification diagram in Plate 1 is reprinted in fig. 3-1 in Appendix 3 for the reader’s convenience. The tables from Plates 2 and 3 are reprinted as table 4-1 and table 4-2 for the reader’s convenience.

Klemme Basin Classification

Many classifications of petroleum basins have been prepared. In one of the earliest, Kay (1951) outlined the basic architecture of geosynclines, with suggestions as to their origins. Kay’s work preceded the later theory of plate tectonics. Klemme (1977, 1980a, 1980b, 1983, 1984) gives a summary description of petroleum basins together with their classification, based upon basin origin and inherent geological characteristics. This classification is simple and readily applicable to the understanding of heavy oil and natural bitumen occurrence. The Klemme basin types assigned to the heavy oil and natural bitumen basins described in this report correspond to the assignments made in St. John, Bally, and Klemme (1984). In some cases of multiple type designations in St. John, Bally, and Klemme (1984) a unique type designation was resolved by reference to Bally (1984) or Bally and Snelson (1980). Only a few of the basins originally designated as multiple types in St. John, Bally and Klemme (1984) appear to contain heavy oil and natural bitumen.

Table 7 summarizes the criteria upon which Klemme based his classification. The general description of the resource endowment associated to the Klemme basin classification is based upon oilfield (and gasfield) data of the world as of 1980 without regard to the density or other chemical attributes of the hydrocarbons they contain (Klemme, 1984). At the time of Klemme’s work, the average density U.S. refinery crude oil was about 33.7°API (Swain, 1991). A decline in the average to about 30.6°API by 2003 perhaps signifies the increasing importance of heavy oil in the mix (Swain, 2005).

Generally, basins may be described as large or small and linear or circular in shape. They may also be described by the ratio of surface area to sedimentary volume. The basement profile or basin cross-section, together with the physical description, permits the interpretation of the fundamental basin architecture. The basin can then be placed within the relevant plate tectonic framework and assigned to one of four basin types, of which two have sub-types. A diagram of the Klemme basin types appears on Plate 1, color-coded to the basins on the map.

In the following section we provide descriptions of the basin types from Klemme (1980b, 1983, 1984) followed by discussion of the heavy oil and natural bitumen occurrences within those same basin types, summary data for which are given in table 4. Because most heavy oil and natural bitumen deposits have resulted from the alteration of conventional and medium oil, the factors leading to the initial conventional and medium oil accumulations are relevant to the subsequent occurrence of heavy oil and natural bitumen.

Type I. Interior Craton Basins

The sediment load in these basins is somewhat more clastic than carbonate. Reservoir recoveries are low and few of the basins contain giant fields. Traps are generally related to central arches, such as the Cincinnati arch, treated here as a separate province (Plates 1-3), or the arches of the Siberian platform (see below for further explanation). Traps also are found in smaller basins over the craton, such as the Michigan basin. The origin of these depressions is unclear although most of them began during the Precambrian (Klemme, 1980a, 1980b).

The six Type I basins having heavy oil contain less than 3 billion barrels of oil in place and of this 93% occurs in the Illinois basin alone. Four Type I basins that contain natural bitumen have 60 billion barrels of natural bitumen in place, with nearly 99% in the Tunguska basin in eastern Siberia and the rest in the Illinois basin. The Tunguska basin covers most of the Siberian platform, around the borders of which are found cratonic margin basins of Type IIA. For convenience all the resource is assigned to the Tunguska basin. The prospective additional resource of 52 billion barrels is almost certainly an absolute minimum value for this potentially valuable but difficult to access area (Meyer and Freeman, 2006.)

Type II. Continental Multicyclic Basins

Type IIA. Craton margin (composite)

These basins, formed on continental cratonic margins, are generally linear, asymmetrical in profile, usually beginning as extensional platforms or sags and ending as compressional foredeeps. Therefore they are multicyclic basins featuring a high ratio of sediment volume to surface area. Traps are mainly large arches or block uplifts and may be found in rocks of either the lower (platform) or upper (compression) tectonic cycle. About 14% of conventional oil discovered in the world by 1980 is from marginal cratonic basins (Klemme, 1980a, 1980b).

Type IIA basins are of moderate importance with respect to heavy oil, with about 158 billion barrels of oil in place distributed among 28 basins. Three Type IIA basins, the Western Canada Sedimentary, Putumayo, and Volga-Ural, have combined total heavy oil resource of 123 billion barrels of oil in place, or 78% of the total for Type IIA basins.

In comparison, natural bitumen in 24 Type IIA basins accounts for 2,623 billion barrels of natural bitumen in place, or nearly 48% of the world natural bitumen total. The Western Canada Sedimentary basin accounts for 2,334 billion barrels of natural bitumen in place, or about 89%. Of the Canadian total, 703 billion barrels of natural bitumen in place is prospective additional oil, largely confined to the deeply buried bitumen in the carbonate that underlie the Peace River and part of the Athabasca oil sand deposit in an area known as the Carbonate Triangle. The significance of the Canadian deposits lies in their concentration in a few major deposits: Athabasca, from which the reservoir is exploited at or near the surface and shallow subsurface, and Cold Lake and Peace River, from which the bitumen is extracted from the subsurface. Two other basins contain much less but still significant amounts of natural bitumen, the Volga-Ural basin in Russia (263 billion barrels of natural bitumen in place) and the Uinta basin in the United States (12 billion barrels of natural bitumen in place). The Volga-Ural deposits are numerous, but individually are small and mostly of local interest. The Uinta deposits are much more concentrated aerially, but are found in difficult terrain remote from established transportation and refining facilities.

Type IIB. Craton accreted margin (complex)

These basins are complex continental sags on the accreted margins of cratons. Architecturally, they are similar to Type IIA basins, but begin with rifting rather than sags. About three-quarters of Type IIA and IIB basins have proven productive, and they contain approximately one-fourth of the world's total oil and gas (Klemme, 1980a, 1980b).

The 13 Type IIB basins contain a moderate amount of heavy oil (193 billion barrels of oil in place). The two most significant basins are in Russia, West Siberia and Timan-Pechora. These, together with most of the other Type IIB heavy oil basins, are of far greater importance for their conventional and medium oil resources.

Five Type IIB basins hold 29 billion barrels of natural bitumen in place. Only the Timan-Pechora basin contains significant natural bitumen deposits, about 22 billion barrels of natural bitumen in place. Unfortunately, this resource is distributed among a large number of generally small deposits.

Type IIC. Crustal collision zone (convergent plate margin)

These basins are found at the crustal collision zone along convergent plate margins, where they are downwarped into small ocean basins. Although they are compressional in final form, as elongate and asymmetrical foredeeps, they begin as sags or platforms early in the tectonic cycle. Type IIC downwarp basins encompass only about 18 percent of world basin area, but contain nearly one-half of the world's total oil and gas. These basins are subdivided into three subtypes, depending on their ultimate deformation or lack thereof: Type IICa, closed; Type IICb, trough; and Type IICc, open (Klemme, 1980a, 1980b).

Although basins of this type begin as downwarps that opened into small ocean basins (Type IICc), they may become closed (Type IICa) as a result of the collision of continental plates. Upon closing, a large, linear, asymmetric basin with sources from two sides is formed, resembling a Type IIA basin. Further plate movement appears to destroy much of the closed basin, leaving a narrow, sinuous foredeep, that is, a Type IICb trough. Relatively high hydrocarbon endowments in the open and the closed types may be related to above-normal geothermal gradients, which accentuates hydrocarbon maturation and long-distance ramp migration. Traps are mostly anticlinal, either draping over arches or compressional folds, and are commonly related to salt flowage.

Type IICa basins, with their architectural similarity to Type IIA basins, are the most important of the three Type IIC heavy oil basins. The 15 basins account for 1,610 billion barrels of the heavy oil in place, with the Arabian, Eastern Venezuela, and Zagros basins containing 95% of the total. Of particular interest is the Eastern Venezuela basin which includes large accumulations of conventional and medium oil, while at the same time possessing an immense resource of both heavy oil and natural bitumen.

Type IICa basins also are rich in natural bitumen, with a total of 2,507 billion barrels of natural bitumen in place among the six. About 83% of this occurs in Venezuela, mostly in the southern part of the Eastern Venezuelan basin known as the Orinoco Oil Belt. Here the reservoir rocks impinge upon the

Guyana craton in much the same fashion as the reservoir rocks of the Western Canada Sedimentary basin lap onto the Canadian shield. The only other significant Type IICa accumulation of natural bitumen is found in the North Caspian basin (421 billion barrels of natural bitumen in place).

Fourteen Type IICb basins contain modest amounts of heavy oil (32 billion barrels of oil in place) and even less of natural bitumen (5 billion barrels of natural bitumen in place in seven basins). Much of this resource is found in the Caltanisetta and Durres basins, on either side of the Adriatic Sea. Durres basin resources are aggregated with the South Adriatic and the province is labeled South Adriatic on the plates. Significant amounts of the Caltanisetta resource occurs offshore.

The amount of heavy oil in the 12 Type IICc basins is substantial (460 billion barrels of oil in place). The Campeche, by far the largest, and Tampico basins in Mexico and the North Slope basin in the United States account for 89% of the heavy oil. The Campeche field, which is actually an assemblage of closely associated fields, is found about 65 miles offshore of the Yucatan Peninsula in the Gulf of Mexico. The North Slope basin, on the north coast of Alaska, occurs in an area of harsh climate and permafrost, which makes heavy oil and natural bitumen recovery by the application of thermal (steam) methods difficult both physically and environmentally. The U.S. fields in the East Texas, Gulf Coast, and Mississippi Salt Dome basins account for only 5% of the heavy oil in basins of this type.

Only a small amount of natural bitumen (24 billion barrels) has been discovered in eight Type IICc basins. Two of these, the North Slope and South Texas Salt Dome basins, are significant for possible future development.

Type III. Continental Rifted Basins

Type IIIA. Craton and accreted zone (rift)

These are small, linear continental basins, irregular in profile, which formed by rifting and simultaneous sagging in the craton and along the accreted continental margin. About two-thirds of them are formed along the trend of older deformation belts and one-third are developed upon Precambrian shields. Rifts are extensional and lead to block movements so that traps are typically combinations. Oil migration was often lateral, over short distances. Rift basins are few, about five percent of the world's basins, but half of them are productive. Because of their high recovery factors, Type IIIA basins accounted for 10% of the world's total recoverable oil and gas in 1980 (Klemme, 1980a, 1980b).

Globally, there are 28 Type IIIA heavy oil basins, containing 222 billion barrels of oil in place   The Bohai Gulf basin in China accounts for 63% of the heavy oil, with an additional 11% derived from the Gulf of Suez and 10% from the Northern North Sea. Outside of these, most Type IIIA basins contain just a few deposits. The five basins in Type IIIA have almost 22 billion barrels of natural bitumen in place, but half of that is located in the Northern North Sea basin.

Type IIIB. Rifted convergent margin (oceanic consumption)

Type IIIBa basins are classified as back-arc basins on the convergent cratonic side of volcanic arcs. They are small, linear basins with irregular profiles (Klemme, 1980a, 1980b).

Not unlike Type IIIA basins, the volume of heavy oil found in the Type IIIBa basins is small. Seventeen heavy oil basins contain 49 billion barrels of oil in place and 83% of this amount is in Central Sumatra.

Just 4 billion barrels of natural bitumen in place are identified in the Type IIIA basin called Bone Gulf. Small amounts are also known to occur in the Cook Inlet and Tonga basins.

Type IIIBb basins are associated with rifted, convergent cratonic margins where wrench faulting and subduction have destroyed the island arc. They are small, linear, and irregular in profile.

The 14 Type IIIBb basins containing heavy oil account for only 134 billion barrels of oil in place. These basins are only moderately important on a global scale, but have been very important to the California oil industry. The seven such basins of California - Central Coastal, Channel Islands, Los Angeles, Sacramento, San Joaquin, Santa Maria, and Ventura – equal 129 billion barrels of oil in place or 96%.

There are nine Type IIIBb basins that report natural bitumen deposits. They contain 4 billion barrels of natural bitumen in place, about half of which is in the Santa Maria basin.

Types IIIBa and IIIBb basins comprise about seven percent of world basin area, but only one-quarter of the basins are productive for oil of all types. However, the productive ones, which represent only two percent of world basin area, yield about seven percent of total world's oil and gas (Klemme, 1983). Some of these productive basins, particularly those located in California, have high reservoir recovery factors.

Type IIIBc basins are small and elongate, irregular in profile, and occupy a median zone either between an oceanic subduction zone and the craton or in the collision zone between two cratonic plates. They result from median zone wrench faulting and consequent rifts. Such basins make up about three and one-half percent of world basin area and contribute two and one-half percent of total world oil and gas.

Type IIIBc basins are important to the occurrence of heavy oil (351 billion barrels of oil in place). Although there are nine basins of this type, 92% of the heavy oil is concentrated in the Maracaibo basin. The Maracaibo basin also yields 95% of the 178 billion barrels of natural bitumen in place in the five basins containing this type of oil. This makes the Maracaibo basin unique: no other basin type is so completely dominated by a single basin.

Type IIIC. Rifted passive margin (divergence)

These basins, often aptly called pull-apart basins, are extensional, elongate, and asymmetric. Located along major oceanic boundaries of spreading plates, they are divergent and occupy the intermediate zone between thick continental crust and thin oceanic crust. They appear to begin with a rifting stage, making possible the later sedimentary fill from the continent. Type IIIC basins, comprising 18 percent of the world's basin area, are mostly offshore and are often in water as deep as 5,000 feet. For this reason their development has been slow but is accelerating as traditional, easily accessible basins reach full development and world demand for petroleum increases (Klemme, 1980a, 1980b).

Twenty-eight Type IIIC basins yield 158 billion barrels of heavy oil in place, but one, the offshore Campos basin, contains 66% of this heavy oil. These continental margin basins must at some point in their histories have been sufficiently elevated to permit their generated conventional oil to be degraded. It is possible that the heavy oil could be very immature, having undergone only primary migration and later elevation. The geologic history of such basins does not encourage this view. However, the oil could well have been degraded bacterially at depth according to the recently proposed mechanisms suggested by Head, Jones, and Larter (2003) and Larter and others (2006). In a pull-apart basin the sediments would have accumulated rapidly and at depth, the expressed oil then was subject to degradation. The problem with degradation at depth is the loss of mobility unless it can be demonstrated that the oil was never elevated and, in fact, the Campos basin oil is deep, occurring at an average depth of nearly 8,400 feet.

The bitumen resource in Type IIIC basins is small (47 billion barrels of natural bitumen in place in seven basins), as are nearly all bitumen occurrences in comparison with the Western Canada Sedimentary and Eastern Venezuela basins. But the 38.3 billion barrels of natural bitumen in place in the Ghana basin of southwestern Nigeria is exploitable and the amount of the resource may be understated. Like many bitumen deposits it awaits more detailed evaluation.

Type IV. Delta (Tertiary to recent)

Deltas form along continental margins as extensional sags, are circular to elongate, and show an extremely high ratio of sediment fill to surface area. Architecturally, they are modified sags comprised of sediment depocenters and occur along both divergent and convergent cratonic margins. Although by 1980 delta basins provide two and one-half percent of world basin area and perhaps six percent of total oil and gas (Klemme, 1980a, 1980b), they account for more of the conventional resource endowment with the recent successful exploration in frontier deep water areas.

The three Type IV delta basins produce scant heavy oil (37 billion barrels of oil in place) and no natural bitumen. This is related to the extremely high ratio of sediment fill to surface area and that these basins exhibited rapid burial of the source organic matter. Burial is constant and uninterrupted, providing very limited opportunity for degradation of the generated petroleum.

Type V. Fore-Arc Basins

Fore-arc basins are located on the ocean side of volcanic arcs. They result from both extension and compression, are elongate and asymmetrical in profile, and architecturally are the result of subduction. Fore-arc basins are few in number and generally not very productive (Klemme, 1980a, 1980b).

Very small amounts of heavy oil are found in the Barbados basin. Although a natural bitumen deposit is reported in the Shumagin basin, volume estimates are not available.

Essentially no heavy oil or natural bitumen is found in fore-arc basins because these basins do not generate large quantities of petroleum of any type and therefore provide relatively little material to be degraded.

Regional Distribution of Heavy Oil and Natural Bitumen

The preceding discussion has been concerned with the distribution of heavy oil and natural bitumen in the world's geological basins. This is of paramount interest in the exploration for the two commodities and for their exploitation. The chemical and physical attributes of the fluids and the reservoirs which contain them do not respect political boundaries.

At the same time it is necessary to understand the geography of the heavy oil and natural bitumen for both economic and political reasons. These factors will be dealt with in detail in a subsequent report. The bar graphs on Plates 2 and 3 give the regional distribution of total and discovered original oil in-place for heavy oil and natural bitumen, respectively. The distribution of the resources is given in table 8. The western hemisphere accounts for about 52 percent of the world's heavy oil and more than 85 percent of its natural bitumen. The Middle East and South America have the largest in-place volumes of heavy oil, followed by North America. North and South America have, by far, the largest in-place volumes of natural bitumen. Very large resource deposits are also known in eastern Siberia but insufficient data are available to make more than nominal size estimates.

Summary

From the preceding basin discussion, Klemme basin Type IICa is by far the most prolific in terms of heavy oil. For natural bitumen Klemme basin Type IIA and Type IICa are the most prolific. The basin types involved are architecturally analogous, beginning with depositional platforms or sags and ending up as foredeeps. They differ only in their modes of origin. What they have in common is truncation against cratonic masses updip from rich source areas. This situation permitted immense accumulations of conventional oil at shallow depths, with near ideal conditions for oil entrapment and biodegradation resulting in formation of heavy oil and bitumen accumulations. The prospective resources from the prospective additional resource deposits in these basins are larger than the discovered resources of many basin types.

The Klemme basin classification system includes elements of basin development and architecture that control basin type. The observed pattern of the heavy oil and natural bitumen occurrences across basin types is consistent with the formation of heavy oil and natural bitumen through the process of degradation of conventional oil. Only relatively small quantities of heavy oil were found in the Interior Craton (Type I), Deltas (Type IV) and Fore-Arc basins (Type V).

Type IICa basins, including the Arabian, Eastern Venezuela, and Zagros, have the largest endowments of heavy oil and also contain the largest amounts of conventional oil. Large volumes of heavy oil are also found in both Type IICc basins, notably, the Campeche, Tampico, and North Slope basins, and in Type IIIBc basins, primarily Maracaibo basin. For natural bitumen, the Western Canada Sedimentary and Eastern Venezuela basins have similar development histories and basin architectural features. Some basin development patterns promote the formation of greater volumes of heavy oil and natural bitumen than others. This is seen most clearly in present occurrences of heavy oil and natural bitumen in the Type IICa and Type IICc basins, with their rich source areas for oil generation and up-dip migration paths to entrapment against cratons. Conventional oil may easily migrate through the tilted platforms until the platforms are breached at or near surface permitting deveopment of asphaltic seals.

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Tables 1–8

Table 1. Some chemical and physical attributes of crude oils (averages).

[cP, centipoise; wt%, weight percent; mgKOH/g, milligrams of potassium hydroxide per gram of sample; sp gr, specific gravity; vol%, volume percent; ppm, parts per million; Concarbon, Conradson carbon; VOC, volatile organic compounds; BTEX, benzene, toluene, ethylbenzene, and xylenes]

Attribute	Unit	Conventional oil (131 basins, 8148 deposits)	Medium oil (74 basins, 774 deposits)	Heavy oil (127 basins, 1199 deposits)	Natural bitumen (50 basins, 305 deposits)
API gravity	degrees	38.1	22.4	16.3	5.4
Depth	feet	5,139.60	3,280.20	3,250.00	1,223.80
Viscosity (77°F)	cP	13.7	34	100,947.00	1,290,254.10
Viscosity (100°F)	cP	10.1	64.6	641.7	198,061.40
Viscosity (130°F)	cP	15.7	34.8	278.3	2,371.60
Conradson Carbon	wt%	1.8	5.2	8	13.7
Coke	wt%	2.9	8.2	13	23.7
Asphalt	wt%	8.9	25.1	38.8	67
Carbon	wt%	85.3	83.2	85.1	82.1
Hydrogen	wt%	12.1	11.7	11.4	10.3
Nitrogen	wt%	0.1	0.2	0.4	0.6
Oxygen	wt%	1.2		1.6	2.5
Sulfur	wt%	0.4	1.6	2.9	4.4
Reid vapor pressure	psi	5.2	2.6	2.2	
Flash point	°F	17	20.1	70.5	
Acid number	mgKOH/g	0.4	1.2	2	3
Pour point	°F	16.3	8.6	19.7	72.9
C1-C4	vol%	2.8	0.8	0.6	
Gasoline + naphtha	vol%	31.5	11.1	6.8	4.4
Gasoline + naphtha	sp gr	0.76	0.769	0.773	0.798
Residuum	vol%	22.1	39.8	52.8	62.2
Residuum	sp gr	0.944	1.005	1.104	1.079
Asphaltenes	wt%	2.5	6.5	12.7	26.1
Asphaltenes + resins	wt%	10.9	28.5	35.6	49.2
Aluminum	ppm	1.174	1.906	236.021	21,040.03
Copper	ppm	0.439	0.569	3.965	44.884
Iron	ppm	6.443	16.588	371.05	4,292.96
Mercury	ppm	19.312	15	8.74	0.019
Nickel	ppm	8.023	32.912	59.106	89.137
Lead	ppm	0.933	1.548	1.159	4.758
Titanium	ppm	0.289	0.465	8.025	493.129
Vanadium	ppm	16.214	98.433	177.365	334.428
Residue Concarbon	wt%	6.5	11.2	14	19
Residue Nitrogen	wt%	0.174	0.304	0.968	0.75
Residue Nickel	ppm	25.7	43.8	104.3	
Residue Sulfur	ppm	1.5	3.2	3.9	
Residue Vanadium	ppm	43.2	173.7	528.9	532
Residue viscosity (122°F)	cP	1,435.80	4,564.30	23,139.80	
Total BTEX volatiles	ppm	10,011.40	5,014.40	2,708.00	
Total VOC volatiles	ppm	15,996.30	8,209.20	4,891.10	

Table 2. Conversion factors and equivalences applied to standardize data.

Standard unit in this report	Units as reported in literaure	Formula
API gravity		
°API (degrees)	specific gravity (sp gr), (g/cm^3)	= (141.5/(sp gr))-131.5
Area		
acre	square mile (mi^2)	= (1/640) mi^2
	square kilometer (km^2)	= 0.00405 km^2
	hectare (ha)	= 0.405 ha
Asphalt in crude		
weight percent (wt%)	Conradson Carbon Residue (CCR)	= 4.9× (CCR)
Barrels of oil		
barrel (bbl), (petroleum, 1 barrel=42 gal)	cubic meter (m^3)	= 0.159 m^3
	metric tonne (t)	= 0.159× (sp gr) ×t
Coke in crude		
weight percent (wt%)	Conradson Carbon Residue (CCR)	= 1.6× (CCR)
Gas-oil ratio		
cubic feet gas/barrel oil (ft^3 gas/bbl oil)	cubic meters gas/cubic meter oil (m^3 gas/m^3 oil)	= 0.18× (m^3gas/m^3oil)
Parts per million		
parts per million (ppm)	gram/metric tonne (g/t)	= g/t
	milligram/kilogram (mg/kg)	= mg/kg
	microgram/gram (µg/g)	= µg/g
	milligram/gram (mg/g)	= 0.001 mg/g
	weight percent (wt%)	= 0.0001 wt%
Parts per billion		
parts per billion (ppb)	parts per million (ppm)	= 0.001 ppm
Permeability		
millidarcy (md)	micrometer squared (μm^2)	= 1,000 μm^2
Pressure		
pound per square inch (psi)	kilopascal (kPa)	= 6.89 kPA
	megapascal (Mpa)	= 0.00689 MPa
	bar	= 0.0689 bar
	kilograms/square centimeter (kg/cm^2)	= 0.0703 kg/cm^2
Specific gravity (density)		
specific gravity (sp gr), (g/cm^3)	°API (degrees)	= 141.5/(131.5+°API)
Temperature		
degrees Fahrenheit (°F)	degrees Celsius (°C)	= (1.8×°C)+32
degrees Celsius (°C)	degrees Fahrenheit (°F)	= 0.556×(°F-32)
Viscosity (absolute or dynamic)		
centipoise (cP)	Pascal second (Pa·s)	= 0.001 Pa·s
	millipascal second (mPa·s)	= mPa·s

Table 2. Conversion factors and equivalences applied to standardize data.—Continued

Standard unit in this report	Units as reported in literaure	Formula
	Viscosity (absolute or dynamic)—Continued	
centipoise (cP)—cont.	kinematic viscosity[1]: centistroke (cSt), (mm²/sec)	= cSt × (sp gr)
	Saybolt Universal Seconds (SUS) at 100°F, for given density	= (SUS /4.632)× (sp gr)
	Saybolt Universal Seconds (SUS) at 100°F, for given °API	= (SUS /4.632)×(141.5/(131.5+°API))
	Weight percent	
weight percent (wt%)	parts per million (ppm)	= 10,000 ppm

[1] Kinematic viscosity is equal to the dynamic viscosity divided by the density of the fluid, so at 10°API the magnitudes of the two viscosities are equal.

Table 3. Total original in place resource calculation protocol when discovered oil in place is unavailable.

Define—

- OOIP-disc.: Original Oil In Place, discovered
- RF: Recovery factor (%)
- R: Reserves, known
- OR: Reserves, original sometimes called, known recovery, ultimate production if so reported
- AP: Production, annual
- CP: Production, cumulative
- PA: Prospective additional oil in place resource
- TOOIP = Total original oil in place

Calculations are based given data, which always receives priority; CP, AP and PA are never calculated and must be from published sources. (Assume CP, AP, PA are given)—

- R = 20×AP. This assumes a 20-year life or production plan for the viscous oil.
- OR = R+CP
- RF = 0.1 for clastic reservoirs or if no lithology is reported
- RF = 0.05 for carbonate reservoirs
- OOIP-disc. = OR/RF
- TOOIP = OOIP-disc. + PA

Table 4. Heavy oil and natural bitumen resources in billions of barrels of oil (BBO) and average characteristics of heavy oil and natural bitumen by basin type. Average values for gravity, viscosity, depth, thickness permeability are weighted by volume of oil in place discovered in each heavy oil or natural bitumen deposit by basin type; except for API gravity of heavy oil Type I, where because of relatively few deposits and several outlier values, a trimmed weighted mean value is shown.

[Volumes may not add to totals due to independent rounding; BBO, billions of barrels of oil; cP, centipoise]

Basin type	Total original oil in place (BBO)	Discovered oil in place (BBO)	API gravity (degrees)	Viscosity (cP @ 100°F)	Depth (feet)	Thickness (feet)	Porosity (percent)	Permeability (millidarcy)	Temperature (°F)
Heavy oil									
I……….	3	2	15.9	724	1,455	11	15.3	88	122
IIA…….	158	157	16.3	321	4,696	36	22.8	819	102
IIB…….	181	181	17.7	303	3,335	96	27.2	341	82
IICa…...	1,610	1,582	15.5	344	3,286	150	24	242	144
IICb…...	32	32	15.4	318	3,976	161	16.9	2,384	126
IICc…...	460	460	17.8	455	6,472	379	19.6	1,080	159
IIIA……	222	222	16.3	694	4,967	279	24.9	1,316	159
IIIBa…..	49	49	19.2	137	558	838	24.9	2,391	122
IIIBb…..	134	134	15.8	513	2,855	390	31.9	1,180	116
IIIBc…..	351	351	13.5	2,318	4,852	142	20.1	446	145
IIIC……	158	158	17.2	962	7,227	273	25.1	868	159
IV……..	37	37	17.9	-	7,263	1,195	27.9	1,996	155
V………	<1	<1	18	-	1,843	135	30	-	144
All types	3,396	3,366	16	641	4,213	205	23.7	621	134
Natural bitumen									
I……….	60	8		-	20	317	5.5	100	
IIA…….	2,623	1,908	6.8	185,407	223	53	0.4	611	173
IIB…….	29	26	4.5	-		209	13.1	57	113
IICa…...	2,509	2,319	4.4	31,789	806	156	29.8	973	174
IICb…...	5	5	6.8	-	8,414	1,145	4.7	570	181
IICc…...	24	23	5	1,324	3,880	82	32.4	302	263
IIIA……	22	22	8.7	-	4,667	882	30.3	1,373	85
IIIBa…..	4	4	-	-	-	-	-	-	-
IIIBb…..	3	3	6.7	500,659	3,097	586	28.6	2,211	89
IIIBc…..	178	178	9.5	1,322	8,751	52	34	751	139
IIIC……	47	14	7.3	-	900	103	23.1	2,566	117
IV……..	0	0							
V………	0	0							
All types	5,505	4,512	4.9	198,061	1,345	110	17.3	952	158

Table 5. Enhanced oil recovery (EOR) methods for heavy oil showing primary reservoir threshold criteria.

[modified from Taber, Martin, and Seright (1997a,b); cP, centipoises; PV, pore volume; ft, feet; md, millidarcy; °F, degrees Fahrenheit, wt%, weight percent]

Method	Gravity (°API)	Viscosity (cP)	Oil composition	Oil saturation (%PV)	Lithology	Net thickness (ft)	Average permeability (md)	Depth (ft)	Temperature (°F)
					Immiscible gases				
Immiscible gases[a]	>12	<600	Not critical	>35	Not critical	Not critical	Not critical	>1,800	Not critical
					Enhanced waterflood				
Polymer	>15	<150	Not critical	>50	Sandstone preferred	Not critical	>10[b]	<9,000	>200-140
					Thermal/mechanical				
Combustion	>10	<5,000	Asphaltic components	>50	Highly porous sandstone	>10	>50[c]	<11,500	>100
Steam	>8	<200,000	Not critical	>40	Highly porous sandstone	>20	>200[d]	<4500	Not critical
Surface mining	>7	0 cold flow	Not critical	>8 wt% sand	Mineable oil sand	>10[e]	Not critical	>3:1 overburden: sand ratio	Not critical

[a] Includes immiscible carbon dioxide flood.

[b] >3 md for some carbonate reservoirs if the intent is to sweep only the fracture systems.

[c] Transmissibility > 20md-ft/cP.

[d] Transmissibility > 50md-ft/cP.

[e] See depth.

Table 6. Listing of countries reporting deposits of heavy oil and/or natural bitumen grouped by region. (See inset maps of regional distribution on Plates 2 and 3.)

North America	South America	Europe	Africa	Transcaucasia	Middle East	Russia	South Asia	East Asia	Southeast Asia and Oceania
Canada	Argentina	Albania	Algeria	Azerbaijan	Bahrain	Russia	Bangladesh	China	Australia
Mexico	Barbados	Austria	Angola	Georgia	Iran		India	Japan	Brunei
United States	Bolivia	Belarus	Cameroon	Kazakhstan	Iraq		Pakistan	Taiwan	Indonesia
	Brazil	Bosnia	Chad	Kyrgyzstan	Israel				Malaysia
	Colombia	Bulgaria	Congo (Brazzaville)	Tajikistan	Jordan				Myanmar
	Cuba	Croatia	Democratic Republic of Congo (Kinshasa)	Turkmenistan	Kuwait				Philippines
	Ecuador	Czech Republic	Egypt	Uzbekistan	Neutral Zone				Thailand
	Guatemala	France	Equatorial Guinea		Oman				Tonga
	Peru	Germany	Gabon		Qatar				Vietnam
	Suriname	Greece	Ghana		Saudi Arabia				
	Trinidad & Tobago	Hungary	Libya		Syria				
	Venezuela	Ireland	Madagascar		Turkey				
		Italy	Morocco		Yemen				
		Malta	Nigeria						
		Moldova	Senegal						
		Netherlands	South Africa						
		Norway	Sudan						
		Poland	Tunsia						
		Romania							
		Serbia							
		Slovakia							
		Spain							
		Sweden							
		Switzerland							
		Ukraine							
		United Kingdom							

Table 7. Attributes of Klemme basin types.

[Sources for attributes 1-15 are Klemme (1980a, 1980b, 1984) and attributes 16 and 17 are from this report]

	Type I	Type IIA	Type IIB	Type IICa
	Craton interior	**Continental multicycle basins, craton margin**	**Continental multicycle basins: craton/acreted zone rift-faulted**	**Continental interior multicycle basins: close collision zone at paleoplate margin**
1. Crustal zone	Continental craton	Continental craton	Contnental craton and accreted zone	Ocean crust early stages then continental crust of craton and accreted zone
2. Tectonic setting	Continenal crust within interior of craton, near or upon Precambrian sheld areas	Continental crust on exterior margin of craton, basins become multicylic ion Paleozoic or Mesozoic when a second cycle of sediments derived from uplife encroaches	Continental crust, or on margin of craton	Convergent margin along collision zone of paleoplates
3. Regional stress	Extensional	1st cycle: extension, 2nd cycle: compression	(1st) extension with rifting, (2nd) extensional sag	(1st) regional extension and platform deposits, then rifting, formation of linear sag, (2nd) compression with creation of foredeep
4. Basin size, shape	Large, circular to elongate	Moderate to large, circular to elongate	Large, circular	Large, elongate
5. Basin profile	Symmetrical	Asymmetrical	Irregular to asymmetrical	Asymmetrical
6. Sediment ratio[1]	Low	High	High	High
7. Architectural sequence	Sag	1st cycle: platform or sag, 2nd cycle: foredeep	(1st) rift, (2nd) large circular sag	(1st) platform or sag, (2nd) foredeep
8. Special features	Unconformities, regional arches, evaporite caps	Large traps, basins and arches, evaporite caps	Large traps, basins and arches, evaporite caps	Large traps and basins, evaporite caps, regional arches, regional source seal, fractured reservoirs
9. Basin lithology[2]	Clastic 60%, carbonate 40%	Clastic 75%, carbonate 25%	Clastic 75%, carbonate 25%	Clastic 35%, carbonate 65%
10. Depth of production[3]	Shallow	Shallow 55%, moderate 25%, deep 5%[5]	Shallow 55%, moderate 25%, deep 5%[5]	Shallow 45%, moderate 30%, deep 25%
11. Geothermal gradient	Low	Low	High	High
12. Temperature	Cool	Cool	Cool	High
13. Age	Paleozoic	Paleozoic, Mesozoic	Paleozoic, Mesozoic	Upper Paleozoic, Mesozoic, Tertiary
14. Oil and gas recovery[4]	Low, few giant fields	Average	Generally average	High
15. Traps	Associated with central arches and stratigraphic traps along basin margins	Basement uplifts, mostly arches or blocks	Basement uplifts, mostly combination of structural stratigraphic	Basement uplifts, arches and fault blocks
16. Propensity for heavy oil	Low	Low	Low	High
17. Propensity for natural bitumen	Low	High	Low	High

[1] Sediment ratio: ratio of sediment volume to basin surface area.

[2] Basin lithology: percentages apply to reservoir rocks, not to the basin fill.

[3] Depth of production: shallow, 0-6000 ft.; medium, 6000-9000 ft.; deep, >9000 ft.

[4] Oil and gas recovery (barrels of oil equivalent per cubic mile of sediment): low, <60,000; average, >=60,000 but <300,000; high, >=300,000.

[5] Does not add to 100% in source, Klemme (1980a,b).

Table 7. Attributes of Klemme basin types.—Continued

	Type IICb	Type IICc	Type IIIA	Type IIIBa
	Continental interior multicycle basins: foredeep portion of collision zone at paleoplate margin	**Continental interior multicycle basins: open collision zone at paleoplate margin**	**Continental rifted basins: craton/accreted zone, rift-faulted, with small linear sag**	**Continental rifted basins: back arc rift-faulted convergent margin**
1. Crustal zone	Ocean crust early stages then continental crust of craton and accreted zone	Ocean crust early stages then continental crust of craton and accreted zone	Continental craton and accreted zone	Contintental accreted zone with oceanic crust in early stages
2. Tectonic setting	Convergent margin along collision zone of paleoplates, but retain only proximal or foredeep portion of original sediment suite	Convergent margin along collision zone of paleoplates	Continental, on margin of craton. About two-thirds of Type IIIA basins form along trend of older deformation; remainder on Precambrian shields	Back arc basins along accreted zone of continent, with continental crust involved in later stages of development and ocean crust in the initial stages
3. Regional stress	(1st) regional extension and platform deposits, then rifting, formation of linear sag, (2nd) compression with creation of foredeep	(1st) regional extension and platform deposits, then rifting, formation of linear sag, (2nd) compression with creation of foredeep	(1st) extension with local wrench faulting during rifting, (2nd) sag	(1st) extension with local wrench faulting compression, (2nd) extension and compression
4. Basin size, shape	Large, elongate	Large, elongate	Small to moderate, fault controlled, elongate	Small, elongate
5. Basin profile	Asymmetrical	Asymmetrical	Irregular	Irregular
6. Sediment ratio[1]	High	High	High	High but variable
7. Architectural sequence	(1st) platform or sag, (2nd) foredeep	(1st) platform or sag, (2nd) foredeep	(1st) extension with local wrench faulting druing rifting, (2nd) sag	Rift faulting leading to linear sag, may be followd by wrench faulting
8. Special features	Large traps and basins, evaporite caps, regional arches, regional source seal, fractured reservoirs	Large traps and basins, evaporite caps, regional arches, regional source seal, fractured reservoirs, unconformities	Large traps, evaporite caps, unconformities, regional source seal	Large traps, and unconformities
9. Basin lithology[2]	Clastic 50%, carbonate 50%	Clastic 35%, carbonate 65%	Clastic 60%, carbonate 40%	Clastic 90%, carbonate 10%
10. Depth of production[3]	Shallow 45%, moderate 30%, deep 25%	Shallow 45%, moderate 30%, deep 25%	Moderate 55%, shallow 30%, deep 15%	Shallow 70%, moderate 20%, deep 10%
11. Geothermal gradient	High	High	High	High
12. Temperature	High	High	Normal to high	Normal to high
13. Age	Upper Paleozoic, Mesozoic, Tertiary	Upper Paleozoic, Mesozoic, Tertiary	Upper Paleozoic, Mesozoic, Paleogene, Neogene	Upper Mesozoic, Paleogene and Neogene
14. Oil and gas recovery[4]	Generally low	High	Generally high	Variable
15. Traps	Basement uplifts, arches and fault blocks	Basement uplifts, arches and fault blocks	Basement uplifts, combination structural/stratigraphic; result in fault block movement	Basement uplifts, fault blocks and combination
16. Propensity for heavy oil	Low	Moderate	Moderate	Low
17. Propensity for natural bitumen	Low	Low	Low	Low

Table 7. Attributes of Klemme basin types.—Continued

	Type IIIBb	Type IIIBc	Type IIIC	Type IV	Type V
	Continental rifted basins: transverse rift-faulted convergent margin	**Continental rifted basins: median rift-faulted convengent margin**	**Continental rifted basins: rift-faulted divergent margin, may be subdivided into (a) parallel, or (b) transverse basins**	**Deltas**	**Fore-arc basins**
1. Crustal zone	Contintental accreted zone with oceanic crust in early stages	Contintental accreted zone with oceanic crust in early stages	Ocean crust in early stage, then continental crust of craton and accreted zone	Ocean crust in early stage, then continental crust of craton and accreted zone	Continetal accreted crust and oceanic crust
2. Tectonic setting	Back arc basins along accreted zone of continent, with continental crust involved in later stages of development and ocean crust in the initial stages	Back arc basins along accreted zone of continent, with continental crust involved in later stages of development and ocean crust in the initial stages	Rift faulting along a divergent, passive or pull-apart continental margin	Almost any location: divergent and convergent margins along open or confined coastal areas	Fore-arc basins located on oceanward side of the volcanic arc in subduction or consumption zone
3. Regional stress	(1st) extension and wrench compression, (2nd) extension and compression	(1st) extension and wrench compression, (2nd) extension and compression	Extension leading to rift or wrench faulting	Extension as sag develops but uncertain as to the initial cause of sag, roots being deeply buried	Compression and extension
4. Basin size, shape	Small, elongate	Small, elongate	Small to moderate, elongate	Moderate, circular to elongate	Small, elongate
5. Basin profile	Irregular	Irregular	Asymmetrical	Depocenter	Asymmetrical
6. Sediment ratio[1]	High but variable	High but variable	High	Extremely high	High
7. Architectural sequence	Rift faulting leading to linear sag, may be followd by wrench faulting	Rift faulting leading to linear sag, may be followd by wrench faulting	Linear sage with irregular profile	Roots of deltas deeply buried; extension leads to half-sag with sedimentary fill thickening seaward.	Small linear troughs
8. Special features	Large traps, and unconformities	Large traps, unconformities, and regional arches	Possible unconformities and regional source seals	None	Large traps, and unconformities
9. Basin lithology[2]	Clastic 90%, carbonate 10%	Clastic 90%, carbonate 10%	Clastic 70%, carbonate 30%	Clastic 100%	Clastic 90%, carbonate 10%
10. Depth of production[3]	Shallow 70%, moderate 20%, deep 10%	Shallow 70%, moderate 20%, deep 10%	Deep 60%, moderate 30%, shallow 10%	Deep 65%, moderate 30%, shallow 5%	Shallow 70%, deep 20%, moderate 10%
11. Geothermal gradient	High	Normal to high	Low	Low	High
12. Temperature	Normal to high	Normal to high	Cool	Normal to low	High to normal
13. Age	Upper Mesozoic, Paleogene and Neogene	Upper Mesozoic, Paleogene and Neogene	Upper Mesozoic, Paleogene and Neogene	Paleogene, Neogene, and Quaternary	Upper Mesozoic, Tertiary
14. Oil and gas recovery[4]	Variable	Variable	Low	High	High but variable
15. Traps	Basement uplifts, fault blocks and combination	Basement uplifts, fault blocks and combination	Fault blocks and combination	Primarily tensional growth (roll-over) anticlines and flowage: basement not involved	Fault blocks and combination
16. Propensity for heavy oil	Low	Moderate	Low	Low	Nil
17. Propensity for natural bitumen	Low	Low	Low	Nil	Nil

Table 8. Regional distribution of heavy oil and natural bitumen (billion barrels).

[Volumes may not add to totals due to independent rounding]

Region[1]	Discovered orginal oil in place	Prospective additional	Total original oil in place
Heavy oil			
North America	650	2	651
South America	1099	28	1127
Europe	75	0	75
Africa	83	0	83
Transcaucasia	52	0	52
Middle East	971	0	971
Russia	182	0	182
South Asia	18	0	18
East Asia	168	0	168
Southeast Asia and Oceania	68	0	68
Total	3366	29	3396
Natural bitumen			
North America	1671	720	2391
South America	2070	190	2260
Europe	17	0	17
Africa	13	33	46
Transcaucasia	430	0	430
Middle East	0	0	0
Russia	296	51	347
South Asia	0	0	0
East Asia	10	0	10
Southeast Asia and Oceania	4	0	4
Total	4512	993	5505

[1] See table 6 for a list of countries reporting deposits of heavy oil and/or natural bitumen grouped by regions.

Appendixes 1–4

Appendix 1. Map Basin Name Conventions

Table 1-1. List of geologic provinces where province names used in this report differ from names used in St. John, Bally and Klemme (1984).

Geological province name in this report	Geological province name in St. John, Bally, and Klemme (1984)
Amu Darya	Tadzhik
Arkla	Louisiana Salt Dome
Baikal	Lake Baikal
Barinas-Apure	Llanos de Casanare
Carnarvon	Dampier
Central Montana Uplift	Crazy Mountains
Central Sumatra	Sumatra, Central
East Java	Java, East
East Texas	East Texas Salt Dome
Eastern Venezuela	Maturin
Forest City	Salina-Forest City
Gulf of Alaska	Alaska, Gulf of
Gulf of Suez	Suez, Gulf of
Guyana	Guiana
Junggar	Zhungeer
Kutei	Mahakam
Mae Fang	Fang
Minusinsk	Minisinsk
North Caspian	Caspian, North
North Caucasus-Mangyshlak	Caucasus, North
North Egypt	Western Desert
North Sakhalin	Sakhalin, North
North Sumatra	Sumatra, North
North Ustyurt	Ust Urt
Northern North Sea	North Sea, Northern
Northwest Argentina	Argentina, Northwest
Northwest German	German, Northwest
Northwest Shelf	Dampier
Ordos	Shanganning
Progreso	Guayaquil
Sacramento	Sacramento/San Joaquin
Salinas	Salinas (Mexico)
San Joaquin	Sacramento/San Joaquin
South Adriatic	Adriatic, South
South Palawan	Palawan, South
South Sumatra	Sumatra, South
Timan-Pechora	Pechora
Turpan	Tulufan

Table 1-1. List of geologic provinces where province names used in this report differ from names used in St. John, Bally and Klemme (1984).—Continued

Geological province name in this report	Geological province name in St. John, Bally, and Klemme (1984)
Upper Magdalena	Magdalena, Upper
West Java	Java, West, Sunda
West of Shetlands	Shetlands, West
Western Canada Sedimentary	Alberta
Yukon-Kandik	Yukon/Kandik

The following basins listed in bold type are from the digital mapping file of St. John (1996) and require further explanation:

- **Anadarko**: includes provinces more commonly known as the *Anadarko*, Central Kansas Uplift, Chautauqua Platform, *Las Animas Arch*, Nemaha Anticline-Cherokee Basin, *Ozark Uplift*, Sedgwick, and South Oklahoma Folded Belt (provinces in italics report neither heavy oil nor natural bitumen.)
- **Sacramento/San Joaquin**: separated into two distinct provinces, Sacramento and San Joaquin.
- **North Sea, Southern**: : includes both the Anglo-Dutch and Southern North Sea basins.
- **South Adriatic**: includes both the Durres and South Adriatic basins.

Other comments:

Three separate outlines for Marathon, Ouachita, and Eastern Overthrust are shown as a common province Marathon/Ouachita/Eastern Overthrust in the original St John (1996) but only Ouachita Basin had reported volumes of natural bitumen resources.

Deposits reported for Eastern Venezuela basin include deposits on the island of Trinidad, which are a likely extension of the rock formations from the surface expression of the basin outline.

The plates attach the name of Barinas Apure to the polygonal province labeled Llanos de Casanare in St. John (1996). Barinas Apure is the province name commonly used in Venezuela and Llanos de Casanare is the province name commonly used in Colombia for the same geologic province.

Appendix 2. Basins, Basin Type and Location of Basins having Heavy Oil and Natural Bitumen Deposits

Table 2-1. List of geological basin names, the Klemme basin type, countries, U.S. states or Canadian provinces reporting deposits of heavy oil and/or natural bitumen, and other names cited in literature.

Geological province	Klemme basin type	Country	State/Province	Other names
Aegian	IIIBc	Greece		North Aegean Trough (North Aegean Sea Basin)
Akita	IIIBa	Japan		Akita Basin, Japan Accreted Arc/Accreted Terrane
Amu-Darya	IICa	Tajikistan, Uzbekistan		Tadzhik, Surkhan-Vaksh, Badkhyz High (Murgab Basin), Afghan-Tajik
Amur	IIIBc	Georgia		
Ana Maria	IIIBb	Cuba		Zaza Basin, Greater Antilles Deformed Belt
Anabar-Lena	IIA	Russia		
Anadarko	IIA	United States	Kans.	
Anadyr	IIIBb	Russia		
Angara-Lena	IIA	Russia		
Anglo-Dutch	IIB	Netherlands		Central Graben, North Sea, Southern
Appalachian	IIA	United States	Ky., N.Y.	
Aquitaine	IIIA	France		Ales, Aquitaine, Lac Basin, Parentis, Massif Central, Pyrenean Foothills-Ebro Basin
Arabian	IICa	Bahrain, Iran, Iraq, Jordan, Kuwait, Neutral Zone, Oman, Qatar, Saudi Arabia, Syria		Arabian Basin, Rub Al Khali, Aneh Graben, Aljafr Sub-basin, Oman Platform, Mesopotamian Foredeep, Palmyra Zone, Oman Sub-Basin, Euphrates/Mardin, Ghaba Salt Basin, Greater Ghawar Uplift, Haleb, Qatar Arch, South Oman Salt Basin, Widyan Basin
Arkla	IICc	United States	Ark., La.	Louisiana Salt Dome
Arkoma	IIA	United States	Ark., Okla.	
Assam	IICb	India		
Atlas	IICb	Algeria		Moroccan-Algerian-Tunisian Atlas, Hodna-Constantine
Bahia Sul	IIIC	Brazil		J Equitinhonha
Baikal	IIIA	Russia		Lake Baikal
Balearic	IIIA	Spain		Western Mediterranean, Gulf of Valencia, Barcelona Trough (Catalano-Balearic Basin), Iberic Cordillera
Baltic	I	Sweden		
Baluchistan	IICb	Pakistan		Sulaiman-Kirthar
Barbados	V	Barbados		Lesser Antilles, Northeast Caribbean Deformed Belt
Barinas-Apure	IIA	Venezuela, Colombia		Barinas-Apure Basin, Llanos de Casanare
Barito	IIIBa	Indonesia		Barito Basin
Bawean	IIIBa	Indonesia		
Beibu Gulf	IIIBa	China		Beibuwan (Gulf of Tonkin) Basin
Bengal	IICa	Bangladesh, India		Bengal (Surma Sub-basin), Tripura-Cachar, Barisal High (Bengal Basin), Ganges-Brahmaputra Delta
Beni	IIA	Bolivia		Foothill Belt
Big Horn	IIA	United States	Mont., Wyo.	
Black Mesa	IIB	United States	Ariz.	Dry Mesa, Dineh Bi Keyah
Black Warrior	IIA	United States	Ala., Miss.	
Bohai Gulf	IIIA	China		Bohai Wan (Huabei-Bohai) Basin, Huabei, Pohal, Luxi Jiaoliao Uplift

Table 2-1. List of geological basin names, the Klemme basin type, countries, U.S. states or Canadian provinces reporting deposits of heavy oil and/or natural bitumen, and other names cited in literature.—Continued

Geological province	Klemme basin type	Country	State/Province	Other names
Bombay	IIIC	India		
Bonaparte Gulf	IIIC	Australia		Berkeley Platform (Bonaparte Basin)
Bone Gulf	IIIBa	Indonesia		Bone
Bresse	IIIA	France		Jura Foldbelt
Browse	IIIC	Australia		
Brunei-Sabah	IICc	Brunei, Malaysia		Baram Delta
Cabinda	IIIC	Angola, Congo (Brazzaville), Democratic Republic of Congo (Kinshasa)		Lower Congo Basin, West-Central Coastal
Caltanisetta	IICb	Italy, Malta		Caltanissetta Basin, Ibleian Platform, Sicilian Depression
Cambay	IIIA	India		Cambay North, Bikaner-Nagam, Bombay (in part)
Campeche	IICc	Mexico		Tabasco-Campeche, Yucatan Boderland and Platform, Tobasco, Campeche-Sigsbee Salt, Villahermosa Uplift
Campos	IIIC	Brazil		Cabo Frio High (Campos Basin)
Cantabrian	IIIA	Spain		Offshore Cantabrian Foldbelt (Cantabrian Zone), Spanish Trough-Cantabrian Zone
Carnarvon	IIIC	Australia		Dampier, Northwest Shelf, Carnarvon Offshore, Barrow-Dampier Sub-Basin
Carpathian	IICb	Austria, Czech Republic, Poland, Ukraine		Carpathian Flysch, Carpathian Foredeep, Bohemia, Carpathian-Balkanian
Celtic	IIIA	Ireland		Celtic Sea Graben System, Ireland-Scotland Platform
Central Coastal	IIIBb	United States	Calif.	Coastal, Santa Cruz, Salinas Valley, Northern Coast Range
Central Kansas Uplift	IIA	United States	Kans.	Anadarko
Central Montana Uplift	IIA	United States	Mont.	Crazy Mountains
Central Sumatra	IIIBa	Indonesia		Central Sumatra Basin
Ceram	IICa	Indonesia		North Seram Basin, Banda Arc
Channel Islands	IIIBb	United States		Southern California Borderlands
Chao Phraya	IIIA	Thailand		Phitsanulok Basin, Thailand Mesozoic Basin Belt
Chautauqua Platform	IIA	United States	Okla.	Anadarko
Cincinnati Arch	I	United States	Ky., Ohio	
Cook Inlet	IIIBa	United States	Alaska	Susitna Lowlands
Cuanza	IIIC	Angola		Kwanza Basin, West-Central Coastal
Cuyo	IIB	Argentina		Alvear Sub-basin (Cuyo Basin), Cuyo-Atuel
Dead Sea	IICa	Israel, Jordan		Syrian -African Arc, Levantine, Jafr-Tabuk, Sinai
Denver	I	United States	Colo., Nebr.	Denver-Julesberg
Diyarbakir	IICa	Syria, Turkey		Bozova-Mardin High (Southeast Turkey Fold Belt), Euphrates/Mardin, Zagros Fold Belt
Dnieper-Donets	IIIA	Ukraine		Dnepr-Donets Graben
Doba	IIIA	Chad		
Durres	IICb	Albania		Ionian Basin (zone), South Adriatic, Pre-Adriatic
East China	IIIBa	China, Taiwan		Diaoyu Island Depression (East China Sea Basin)
East Java	IIIBa	Indonesia		Bawean Arch (East Java Basin)
East Texas	IICc	United States	Tex.	East Texas Salt Dome, Ouachita Fold Belt
Eastern Venezuela	IICa	Venezuela, Trinidad and Tobago		Maturin, Eastern Venezuela Basin, Orinoco Oil Belt, Guarico Sub-basin, Trinidad-Tabago

Table 2-1. List of geological basin names, the Klemme basin type, countries, U.S. states or Canadian provinces reporting deposits of heavy oil and/or natural bitumen, and other names cited in literature.—Continued

Geological province	Klemme basin type	Country	State/Province	Other names
Espirito-Santo	IIIC	Brazil		Abrolhos Bank Sub-Basin (Espirito Santo Basin)
Fergana	IIIBc	Kyrgyzstan, Tajikistan, Uzbekistan		
Florida-Bahama	IIIC	Cuba, United States	Fla.	Almendares-San Juan Zone, Bahia Honda Zone, Llasvvillas Zone, Florida Platform, Greater Antilles Deformed Belt
Forest City	I	United States	Kans., Nebr.	Salina-Forest City, Salina, Chadron Arch
Fort Worth	IIA	United States	Tex.	Bend Arch, Fort Worth Syncline, Llano Uplift, Ouachita Overthrust
Gabon	IIIC	Gabon		Gabon Coastal Basin (Ogooue Delta), West-Central Coastal
Gaziantep	IICa	Syria, Turkey		
Ghana	IIIC	Ghana, Nigeria		Benin-Dahomey, Dahomey Coastal
Gippsland	IIIA	Australia		Gippsland Basin
Green River	IIA	United States	Colo., Wyo.	
Guangxi-Guizou	IIB	China		Bose (Baise) Basin, South China Fold Belt
Gulf Coast	IICc	United States	La., Tex.	Mid-Gulf Coast, Ouachita Folded Belt, Burgos
Gulf of Alaska	V	United States	Alaska	
Gulf of Suez	IIIA	Egypt		Gulf of Suez Basin, Red Sea Basin
Guyana	IIIC	Suriname		Guiana, Bakhuis Horst, Guyana-Suriname
Illinois	I	United States	Ill., Ky.	
Indus	IICb	India		Punjab (Bikaner-Nagaur Sub-basin), West Rajasthan
Ionian	IICb	Greece		Epirus, Peloponesus
Irkutsk	IIA	Russia		
Jeanne d'Arc	IIIC	Canada	N.L.	Labrador-Newfoundland Shelf
Jianghan	IIIA	China		Tung-T'Ing Hu
Junggar	IIIA	China		Zhungeer, Anjihai-Qigu-Yaomashan Anticlinal Zone (Junggar)
Kansk	IIA	Russia		
Krishna	IIIC	India		Krishna-Godavari Basin
Kura	IIIBc	Azerbaijan, Georgia		Kura Basin
Kutei	IIIBa	Indonesia		Mahakam
Kuznets	IIB	Russia		
Laptev	IIB	Russia		
Los Angeles	IIIBb	United States	Calif.	
MacKenzie	IV	Canada	N.W.T.	Beaufort Sea, MacKenzie Delta
Mae Fang	IIIA	Thailand		Fang, Mae Fang Basin, Tenasserim-Shan
Maracaibo	IIIBc	Venezuela, Colombia		Maracaibo Basin, Catatumbo
Mauritius-Seychelles	IIIC	Seychelles		
Mekong	IIIC	Vietnam		Mekong Delta Basin
Michigan	I	United States	Mich.	
Middle Magdalena	IIIBc	Colombia		Middle Magdalena Basin
Minusinsk	IIB	Russia		Minisinsk
Mississippi Salt Dome	IICc	United States	Ala., Miss.	
Moesian	IICb	Bulgaria, Moldova, Romania		Moesian Platform-Lom Basin, Alexandria Rosiori Depression (Moesian Platform), Carpathian-Balkanian, West Black Sea

Table 2-1. List of geological basin names, the Klemme basin type, countries, U.S. states or Canadian provinces reporting deposits of heavy oil and/or natural bitumen, and other names cited in literature.—Continued

Geological province	Klemme basin type	Country	State/Province	Other names
Molasse	IICb	Austria, Germany, Italy, Switzerland		Molasse Basin
Morondava	IIIC	Madagascar		
Mukalla	IIIC	Yemen		Sayhut Basin, Masila-Jeza
Natuna	IIIA	Indonesia		
Nemaha Anticline-Cherokee Basin	IIA	United States	Kans., Mo.	Anadarko
Neuquen	IIB	Argentina		Agrio Fold Belt (Neuquen Basin)
Niger Delta	IV	Cameroon, Equatorial Guinea, Nigeria		Abakaliki Uplift (Niger Delta)
Niigata	IIIBa	Japan		Niigata Basin, Yamagata Basin, Japan Volcanic Arc/Accreted Terrane
Nile Delta	IV	Egypt		Nile Delta Basin
North Caspian	IICa	Kazakhstan, Russia		Akatol’ Uplift, Alim Basin, Beke-Bashkuduk Swell Pri-Caspian, Kobyskol’ Uplift, South Emba, Tyub-Karagan
North Caucasus-Mangyshlak	IICa	Russia		Indolo-Kuban-Azov-Terek-Kuma Sub-basins, North Buzachi Arch, Middle Caspian, North Caucasus
North Egypt	IICa	Egypt		Western Desert, Abu Gharadiq
North Sakhalin	IIIBb	Russia		Sakhalin North
North Slope	IICc	United States	Alaska	Arctic Coastal Plains, Interior Lowlands, Northern Foothills, Southern Foothills, Colville
North Sumatra	IIIBa	Indonesia		North Sumatra Basin
North Ustyurt	IIB	Kazakhstan		Ust-Urt
Northern North Sea	IIIA	Norway, United Kingdom		Viking Graben, North Sea Graben
Northwest Argentina	IIA	Argentina		Carandaitycretaceous Basin
Northwest German	IIB	Germany		Jura Trough, West Holstein
Olenek	I	Russia		
Ordos	IIA	China		Shanganning, Qinling Dabieshan Fold Belt
Oriente	IIA	Peru		Acre, Maranon, Upper Amazon
Otway	IIIC	Australia		
Ouachita Overthrust	IIA	United States	Ark.	
Palo Duro	IIA	United States	N. Mex.	Tucumcari
Pannonian	IIIBc	Bosnia and Herzegovina, Croatia, Hungary, Romania, Serbia		Backa Sub-basin (Pannonian Basin)
Paradox	IIB	United States	Utah	
Paris	IIB	France		Anglo-Paris Basin
Pearl River	IIIC	China		Dongsha Uplift (Pearl River Basin), Pearl River Mouth, South China Continental Slope
Pelagian	IICa	Tunisia, Libya		
Permian	IIA	United States	N. Mex., Tex.	Ouachita Fold Belt, Bend Arch, Delaware, Midland
Peten-Chiapas	IICc	Guatemala		Chapayal (South Peten) Basin, North Peten (Paso Caballos), Sierra De Chiapas-Peten, Yucatan Platform
Piceance	IIA	United States	Colo.	
Po	IICb	Italy		Crema Sub-Basin (Po Basin)
Polish	IIIA	Poland		Danish-Polish Marginal Trough, German-Polish

Table 2-1. List of geological basin names, the Klemme basin type, countries, U.S. states or Canadian provinces reporting deposits of heavy oil and/or natural bitumen, and other names cited in literature.—Continued

Geological province	Klemme basin type	Country	State/Province	Other names
Potiguar	IIIC	Brazil		Boa Vista Graben (Potiguar Basin), North-Northeastern Region
Potwar	IICb	Pakistan		Bannu Trough (Potwar Basin), Kohat-Potwar
Powder River	IIA	United States	Mont., Wyo.	
Pripyat	IIIA	Belarus		Pripyat Graben
Progreso	IIIBb	Ecuador		Guayaquil, Gulf Of Gayaquil, Jambeli Sub-basin of Progresso Basin, Santa Elena
Putumayo	IIA	Colombia, Ecuador		Napo, Cuenca Oriente Ecuatoriana
Rhine	IIIA	France, Germany		Upper Rhine Graben
Sacramento	IIIBb	United States	Calif.	Sacramento-San Joaquin
Salawati	IICa	Indonesia		Salawati Basin, Bintuni-Salawati
Salinas	IICc	Mexico		Isthmus Of Tehuantepec, Salinas Sub-basin, Isthmus Saline, Saline Comalcalco
San Joaquin	IIIBb	United States	Calif.	Sacramento-San Joaquin
San Jorge	IIIA	Argentina		Rio Mayo, San Jorge Basin
San Juan	IIB	United States	Ariz., Colo., N. Mex.	
Santa Maria	IIIBb	United States	Calif.	
Santos	IIIC	Brazil		
Sarawak	IICc	Malaysia		Central Luconia Platform
Sedgwick	IIA	United States	Kans.	Anadarko
Senegal	IIIC	Senegal		Bove-Senegal Basins
Sergipe-Alagoas	IIIC	Brazil		Sergipe-Alagoas Basin
Shumagin	V	United States	Alaska	
Sirte	IIIA	Libya		Agedabia Trough (Sirte Basin)
Songliao	IIIA	China		
South Adriatic	IICb	Italy		Adriatic, Marche-Abruzzi Basin (Pede-Apenninic Trough), Plio-Pleist Foredeep, Scaglia
South African	IIIC	South Africa		Agulhas Arch (South African Coastal Basin)
South Burma	IIIBb	Burma		Central Burma Basin, Irrawaddy
South Caspian	IIIBc	Azerbaidjan		South Caspian OGP (Apsheron-Kobystan Region), Emba, Guriy Region
South Oklahoma Folded Belt	IIA	United States	Okla., Tex.	Anadarko
South Palawan	IIIBa	Philippines		China Sea Platform, Palawan Shelf
South Sumatra	IIIBa	Indonesia		Central Palembang Depression (South Sumatra Basin)
South Texas Salt Dome	IICc	United States	Tex.	
South Yellow Sea	IIIA	China		Central Uplift (South Huanghai Basin), Subei Yellow Sea
Southern North Sea	IIB	United Kingdom		Central Graben (North Sea Graben system), Dutsh Bank Basin (East Shetland Platform), Witch Ground Graben
Sudan	IIIA	Sudan		Kosti Sub-Basin (Melut Basin), Muglad Basin, Sudd Basin
Sunda	IIIBa	Indonesia		
Surat	IIB	Australia		
Sverdrup	IICc	Canada	N.W.T.	Mellville
Taiwan	IIIBa	Taiwan		Taihsi Basin

Table 2-1. List of geological basin names, the Klemme basin type, countries, U.S. states or Canadian provinces reporting deposits of heavy oil and/or natural bitumen, and other names cited in literature.—Continued

Geological province	Klemme basin type	Country	State/Province	Other names
Talara	IIIBb	Peru		Talara Basin
Tampico	IICc	Mexico		Tampico-Tuxpan Embayment, Chicontepec, Tampico-Misantla
Tarakan	IIIBa	Indonesia		Bera Sub-basin (Tarakan Basin), Pamusian-Tarakan
Taranto	IICb	Italy		Abruzzi Zone (Apennine Range). Marche-Abruzzi Basin (Pede-Apenninic Trough), Latium, Calabrian
Tarfaya	IIIC	Morocco		Aaiun-Tarfaya
Tarim	IIIA	China		
Thrace	IIIBc	Turkey		Thrace-Gallipoli Basin, Zagros Fold Belt
Timan-Pechora	IIB	Russia		Belaya Depression (Ural Foredeep), Brykalan Depression, Pechora-Kozhva Mega-Arch, Varendey-Adz'va
Timimoun	IIB	Algeria		Sbaa
Tonga	IIIBa	Tonga		
Tunguska	I	Russia		Baykit Antecline
Turpan	IIIA	China		Tulufan
Tyrrhenian	IIIA	Italy		
Uinta	IIA	United States	Utah	
Upper Magdalena	IIIBc	Colombia		Upper Magdalena Basin
Ventura	IIIBb	United States	Calif.	Santa Barbara Channel
Veracruz	IIIC	Mexico		
Verkhoyansk	IIA	Russia		
Vienna	IIIBc	Austria, Slovakia		Bohemia
Vilyuy	IIA	Russia		
Volga-Ural	IIA	Russia		Aksubayevo-Nurlaty Structural Zone, Bashkir Arch, Belaya Depression, Melekess Basin, Tatar Arch, Vishnevo-Polyana Terrace
Washakie	IIA	United States	Wyo.	
West Java	IIIBa	Indonesia		Arjuna Sub-Basin (West Java Basin), Northwest Java
West of Shetlands	IIIC	United Kingdom		Faeroe, West of Shetland
West Siberia	IIB	Russia		West Siberia
Western Canada Sedimentary	IIA	Canada, United States	Alta., Mont., Sask.	Alberta, Western Canada Sedimentary, Sweetgrass Arch
Western Overthrust	IIA	United States	Ariz., Mont., Nev., Utah	Central Western Overthrust, Great Basin Province, Southwest Wyoming, South Western Overthrust
Williston	I	Canada, United States	N. Dak., Sask.	Sioux Uplift
Wind River	IIA	United States	Wyo.	
Yari	IIA	Colombia		Yari Basin
Yenisey-Khatanga	IIA	Russia		
Yukon-Kandik	IIIBb	United States	Alaska	Yukon-Koyukuk
Zagros	IICa	Iran, Iraq		Zagros Fold Beltzagros or Iranian Fold Belt, Sinjar Trough, Bozova-Mardin High, Euphrates/Mardin

Appendix 3. Klemme Basin Classificaton Figure from Plate 1

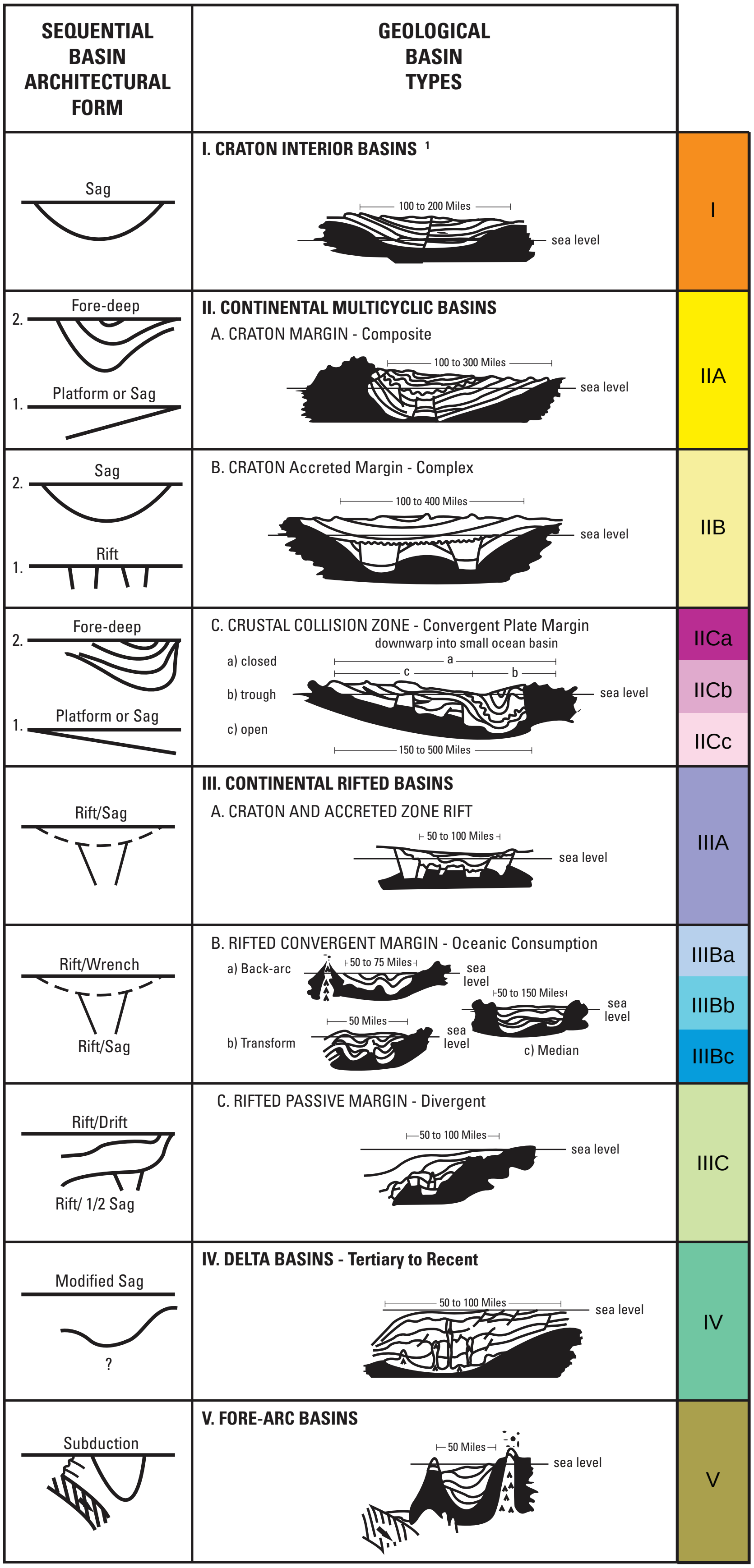

Figure 2-1. Diagram of Klemme basin types from plate 1. Modified from St. John, Bally, and Klemme (1984).

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[1] Cincinati Arch is classified as I-Arch

Appendix 4. Tables from the Plates

Table 4-1. 50 heavy oil basins ranked by volumes of total original heavy oil in place (TOHOIP), showing natural bitumen volumes where reported. Table repeated from plate 2.

[billions of barrels, BBO, 10^9 barrels]

Rank	Geological province	Klemme basin type	Total original heavy oil in place	Original heavy oil in place-discovered	Prospective additional heavy oil in place	Total original natural bitumen in place	Original natural bitumen in place-discovered	Prospective additional natural bitumen in place
1	Arabian	IICa	842	842				
2	Eastern Venezuela	IICa	593	566	27.7	2,090	1,900	190
3	Maracaibo	IIIBc	322	322		169	169	
4	Campeche	IICc	293	293		0.060	0.060	
5	Bohai Gulf	IIIA	141	141		7.63	7.63	
6	Zagros	IICa	115	115				
7	Campos	IIIC	105	105				
8	West Siberia	IIB	88.4	88.4				
9	Tampico	IICc	65.3	65.3				
10	Western Canada Sedimentary	IIA	54.9	54.9		2,330	1,630	703
11	Timan-Pechora	IIB	54.9	54.9		22.0	22.0	
12	San Joaquin	IIIBb	53.9	53.9		< 0.01	< 0.01	
13	Putumayo	IIA	42.4	42.4		0.919	0.919	
14	Central Sumatra	IIIBa	40.6	40.6				
15	North Slope	IICc	37.0	37.0		19.0	19.0	
16	Niger Delta	IV	36.1	36.1				
17	Los Angeles	IIIBb	33.4	33.4		< 0.01	< 0.01	< 0.01
18	North Caspian	IICa	31.9	31.9		421	421	
19	Volga-Ural	IIA	26.1	26.1		263	263	
20	Ventura	IIIBb	25.2	25.2		0.505	0.505	
21	Gulf of Suez	IIIA	24.7	24.7		0.500	0.500	
22	Northern North Sea	IIIA	22.8	22.8		10.9	10.9	
23	Gulf Coast	IICc	19.7	19.7				
24	Salinas	IICc	16.6	16.6				
25	Middle Magdalena	IIIBc	16.4	16.4				
26	Pearl River	IIIC	15.7	15.7				
27	North Ustyurt	IIB	15.0	15.0				
28	Brunei-Sabah	IICc	14.7	14.7				
29	Diyarbakir	IICa	13.5	13.5				

Table 4-1. 50 heavy oil basins ranked by volumes of total original heavy oil in place (TOHOIP), showing natural bitumen volumes where reported. Table repeated from plate 2.—Continued

[billions of barrels, BBO, 10^9 barrels]

Rank	Geological province	Klemme basin type	Total original heavy oil in place	Original heavy oil in place-discovered	Prospective additional heavy oil in place	Total original natural bitumen in place	Original natural bitumen in place-discovered	Prospective additional natural bitumen in place
30	Northwest German	IIB	9.48	9.48				
31	Barinas-Apure	IIA	9.19	9.19		0.38	0.38	
32	North Caucasus-Mangyshlak	IICa	8.60	8.60		0.060	0.060	
33	Cambay	IIIA	8.28	8.28				
34	Santa Maria	IIIBb	8.06	8.06		2.03	2.02	< 0.01
35	Central Coastal	IIIBb	8.01	8.01		0.095	0.025	0.070
36	Big Horn	IIA	7.78	7.78				
37	Arkla	IICc	7.67	7.67				
38	Moesian	IICb	7.39	7.39				
39	Assam	IICb	6.16	6.16				
40	Oriente	IIA	5.92	5.92		0.250	0.250	
41	Molasse	IICb	5.79	5.79		0.010	0.010	
42	Doba	IIIA	5.35	5.35				
43	Morondava	IIIC	4.75	4.75		2.21	2.21	
44	Florida-Bahama	IIIC	4.75	4.75		0.48	0.48	
45	Southern North Sea	IIB	4.71	4.71				
46	Durres	IICb	4.70	4.70		0.37	0.37	
47	Caltanisetta	IICb	4.65	4.65		4.03	4.03	
48	Neuquen	IIB	4.56	4.56				
49	North Sakhalin	IIIBb	4.46	4.46		< 0.01	< 0.01	
50	Cabinda	IIIC	4.43	4.43		0.363	0.363	

Table 4-2. 33 natural bitumen basins ranked by volumes of total original natural bitumen in place (TONBIP). Table repeated from plate 3.

[billions of barrels, BBO, 10^9 barrels]

Rank	Geological province	Klemme basin type	Total original natural bitumen in place	Original natural bitumen in place-discovered	Prospective additional natural bitumen in place
1	Western Canada Sedimentary	IIA	2,330	1,630	703
2	Eastern Venezuela	IICa	2,090	1,900	190
3	North Caspian	IICa	421	421	
4	Volga-Ural	IIA	263	263	
5	Maracaibo	IIIBc	169	169	
6	Tunguska	I	59.5	8.19	51.3
7	Ghana	IIIC	38.3	5.74	32.6
8	Timan-Pechora	IIB	22.0	22.0	
9	North Slope	IICc	19..0	19.0	
10	Uinta	IIA	11.7	7.08	4.58
11	Northern North Sea	IIIA	10.9	10.9	
12	South Caspian	IIIBc	8.84	8.84	
13	Bohai Gulf	IIIA	7.63	7.63	
14	Paradox	IIB	6.62	4.26	2.36
15	Black Warrior	IIA	6.36	1.76	
16	South Texas Salt Dome	IICc	4.88	3.87	1.01
17	Cuanza	IIIC	4.65	4.65	
18	Bone Gulf	IIIBa	4.46	4.46	
19	Caltanisetta	IICb	4.03	4.03	
20	Nemaha Anticline-Cherokee Basin	IIA	2.95	0.70	2.25
21	Morondava	IIIC	2.21	2.21	
22	Yenisey-Khatanga	IIA	2.21	2.21	
23	Santa Maria	IIIBb	2.03	2.02	<0.01
24	Junggar	IIIA	1.59	1.59	
25	Tarim	IIIA	1.25	1.25	
26	West of Shetlands	IIIC	1.00	1.00	
27	Putumayo	IIA	0.919	0.919	
28	Illinois	I	0.890	0.300	0.590
29	South Oklahoma Folded Belt	IIA	0.885	0.058	0.827
30	South Adriatic	IICb	0.510	0.510	
31	Ventura	IIIBb	0.505	0.505	
32	Gulf of Suez	IIIA	0.500	0.500	
33	Florida-Bahama	IIIC	0.477	0.477	

December 2, 2016

Eric Mar, Chair of the Board
Jack Broadbent, Executive Director
John Gioia, Stationary Source Committee Chair
Members of the Board of Directors
Bay Area Air Quality Management District
375 Beale Street, Suite 600
San Francisco, California 94105

Re: Health and Safety Commentary Pertaining to Rule 12-16 and 11-18

Dear Chair Mar, Executive Director Broadbent, Committee Chair Gioia, and Board members,

We are writing as public health and medical professionals and experts to comment on rules under consideration by the Bay Area Air Quality Management District (BAAQMD, Air District) to address harmful emissions of air pollutants. We particularly want to convey the importance of Rule 12-16 to the health of Bay Area residents. Air pollutants are an important cause of disease and death in California and the world, presenting an enormous global burden of disease.

At the outset, we want to note that grave potential changes at the Federal level make imperative local, regional, and state actions to ensure clean air for current and future generations. We hope the BAAQMD, other California air quality districts, and the California Air Resources Board will take even greater leadership in actions affecting the future of our planet.

We also understand the Bay Area must anticipate and plan for economic and population growth, with a significant portion assigned to Contra Costa County.[1] Managing growth in a healthy and sustainable way involves altering underlying systems that drive pollution. At a minimum, avoiding increased pollution from any existing sources is critical.

We are looking to the Air District to take on these major challenges to provide healthy air for all in the Bay Area and to lead the way on local actions that reduce releases of greenhouse gases.

We are therefore interested in the Air District's efforts to reduce hazards associated with the Bay Area refineries. We are concerned that Bay Area refineries are shifting to an even heavier, lower quality feedstock derived from tar sands bitumen. We understand that this shift requires changes to the refineries' infrastructure and methods. We understand the Air District is aware the influx of tar sand crudes is under way and recognizes:

> The use of lower quality crude at refineries could potentially mean increased emissions of air contaminants such as sulfur containing pollutants from sulfur recovery facilities. Emissions could also increase as a result of accidents related to the increased corrosiveness of lower quality crudes. Processing lower quality crudes also requires more intense processing and higher energy requirements, which can result in increased air emissions.[2]

To address these health threats, this letter comments on two proposals under the Air District's review, one to address potential increases in criteria pollutant and greenhouse gas emissions at the refineries and the other to reduce emissions of toxic air contaminants at sources throughout the Bay Area.

The first, Regulation 12, Rule 16, would limit emissions to current levels through enforceable numeric limits on refinery-wide emissions of greenhouse gases (GHG) and particulate matter, thereby preventing increases in emissions of criteria air pollutants and greenhouse gases from Bay Area refineries. By extension, it would reduce pet coke and diesel-related exposures, since pet coke is a major byproduct of dirtier feedstock and since import/export transit will increase with an influx of tar sands. These increases would occur if the refineries processed the dirtier forms of crude oil.

Rule 12-16 would play an important role in avoiding further impairment or degradation of Bay Area air quality from the refineries. The rule would reduce the regional burden of pollution, which will produce health and safety benefits, especially for those proximate to or working in the refineries.[3] It presents the opportunity to avoid increases in net GHG emissions and is in keeping with California's climate change mandate, whereas tar sands refining will clearly impede California from meeting GHG reduction targets.[4]

The Air District is also proposing Regulation 11, Rule 18 to reduce risks from emissions of toxic air contaminants at a wide array of sources in the Bay Area including but not limited to the refineries. Rule 11-18 would broaden the sources for which risks are assessed, set a more protective standard for risks of toxic air contaminants, and incorporate updated toxicity values issued by the Office of Environmental Health Hazard Assessment of the California Environmental Protection Agency (EPA). These are important issues, and with improvements such as tightening the monitoring-to-response timeframe, Rule 11-18 could be an important health effort.

We urge the Air District to go forth with the next step of review for both rules, but to consider them *separately*. They are complementary but fundamentally different, and they address different pollutants. Both can be justified on health grounds.

Below is further elaboration that speaks to the importance of Rule 12-16:

1. Tar sands (bitumen) air emissions will be much greater than those involving current oil feedstock and will carry disproportionately more GHG, particulate matter including sulfates and heavy metals, and sulfur dioxide.[5] Tar sand refining is also more corrosive and presents disproportionately high occupational hazards.

2. A particularly important direct consequence of tar sand refining in the Bay Area may be the resulting increase in emissions and exposure to particulate matter (PM) including PM10, PM2.5, and ultrafine particles (ultrafines, UF). As stated by the Air District, ". . . PM [Particulate Matter] is still by far the air pollutant most harmful to public health in the Bay Area," accounting for 90% of air pollution-related deaths here.[6] The refining of heavier crudes will increase particulate and sulfur dioxide (a PM precursor) concentrations significantly more than refining of traditional crude oils. Moreover, PM from heavy crudes, particularly tar sands (bitumen), will be more toxic, carrying much more of the highly dangerous heavy metals and elements such as vanadium, nickel, and lead.[7]

3. Decades of research have firmly established that exposure to particulate matter is associated with severe health effects, including premature mortality, cardiovascular and pulmonary disease, heart attacks, strokes, and cancer.[8] For example, the U.S. EPA and the World Health Organization (WHO) find that a 1 µg/m^3 increase in PM2.5 is associated with a 1.6% increase in death from cardiovascular disease,[9] and emerging research suggests that UFs pose at least as great a risk for morbidity and mortality as does PM2.5.[10] Physical, neurological, and cognitive adverse effects of air pollution on infants and children have been established, with significant, long-term implications for the individual, their family, and society.[11] Infants and children, the elderly, and those socio-economically disadvantaged, especially those closest to the refineries, are at greatest risk of exposure and are more susceptible to adverse effects of exposure.[12] Poorer communities, largely of color, are both closest in proximity to Bay Area refineries and disproportionately vulnerable to their adverse effects, making an influx of tar sands an environmental justice violation.

4. There are no safe levels of these air pollutants, and every incremental increase of emissions from tar sand refining will increase adverse health outcomes. Bay Area air quality is impaired and in nonattainment for ambient standards for ozone, PM10, and PM2.5[13] (harmful ultrafines are essentially unregulated). While attainment standards are a strategy for advancing health, the California EPA, the U.S. EPA and the WHO all clearly state that the standards do not represent safe levels for exposure to air pollution and its constituents.[14] Moreover, they document that important health effects occur below the existing ambient standards. Therefore, Bay Area residents are already burdened and experiencing excess health consequences from air pollution and any increase in emissions will increase adverse health outcomes.

5. Disproportionately large increases in greenhouse gases emissions will contribute to serious health hazards posed by climate change. The U.S. EPA, under The Clean Air Act, issued an endangerment finding in 2009, concluding that GHG, ". . . endanger both the public health and the public welfare of current and future generations."[15] GHG-associated climate change already endangers health in the Bay Area, with increased risks anticipated in the near future.[16] Very few years are left to reduce GHG emissions and avoid the most severe health consequences.

6. A cap-and-trade alternative to Rule 12-16 would not protect health in the Bay Area. By failing to abate local increases in particulate matter, its toxic constituents, diesel particulate matter, pet coke, and worksite hazards, increasing tar sand pollution in the Bay Area in exchange for potential GHG reductions elsewhere would fail to protect the health of Bay Area residents – especially proximate communities and workers. Assembly Bill 32 (AB32) requires consideration of communities already adversely impacted by air pollution, prohibits measures that place disproportionate burdens on vulnerable communities, and limits market-based mechanisms to those that do not increase toxic air contaminants or criteria air pollutants.[17]

In conclusion, the Air District's own mission, as well as the legislative intent of CEQA and AB32, empower and call upon you to protect the health and air of the Bay Area.[18] We respectfully submit that limiting refinery emissions as outlined in Rule 12-16 is an appropriate course of action. We ask that Rule 12-16 be fairly considered in the upcoming review process, and ultimately adopted.

Thank you for your consideration.

Signed,

Bart Ostro PHD	Former Chief of Air Pollution Epidemiology Section, California EPA, currently Research Faculty, Air Quality Research Center, UC Davis
Amy D Kyle PhD, MPH	School of Public Health, University of California Berkeley (Institution for identification only)
Claire V Broome, MD	Adjunct Professor, Rollins School of Public Health Emory University Assistant Surgeon General, US Public Health Service (retired)
Linda Rudolph MD MPH	Director, Center for Climate Change and Health Oakland CA
Jonathan Heller PhD	Co-Director and Co-Founder, Human Impact Partners Oakland CA
Wendel Brunner MD, PhD, MPH	Former Director of Public Health, Contra Costa Health Services
Kathy Dervin MPH	Senior Climate and Health Consultant, Berkeley CA
Janice L Kirsch MD MPH	Medical oncologist and hematologist
Heather Kuiper DrPH MPH	Public Health Consultant, Oakland CA

HIP HUMAN IMPACT PARTNERS

Center for Climate Change & Health

Cc: Victor Douglas

Endnotes present a sample of the sources supporting this letter.

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[2] Bay Area Air Quality Management District. 2012. Regulatory Concept Paper: Petroleum Refining Emissions Tracking Rule. Draft: October 15.

[3] See for example, Currie J, Heep Ray S, Neidell M. 2011. Quasi-experimental studies suggest that lowering air pollution levels benefits infants' and children's health. *Health Affairs* 30(12):2391-2399. doi: 10.1377/hlthaff.2011.0212; Pope AC, Ezzati M, Dockery DW. 2009. Fine Particulate Air Pollution and Life Expectancy in the United States, *New England Journal of Medicine*, January 22; BAAQMD. 2011. Health Impact Analysis of Fine Particulate Matter In the San Francisco Bay Area.

[4] BAAQMD. 2016. Clean Air Plan and Regional Climate Protection Strategy, Energy Fact Sheet. Available at: http://www.baaqmd.gov/~/media/files/planning-and-research/plans/clean-air-plan-update/energy-fact-sheet-pdf.pdf?la=en (Accessed Nov 28, 2016).

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[7] Meyer RF, Attanasi ED, Freeman PA. 2007. Heavy Oil and Natural Bitumen Resources in Geological Basins of the World. Open File-Report 2007-1084 U.S. Geological Survey. Table 1 on page 14 indicates that bitumen crude has 5 – 21 times higher concentration of these heavy metals and 11 times greater sulfur than conventional oil.

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[9] Hoek G, et al. 2013. Long-term air pollution exposure and cardio-respiratory mortality: A review. *Environmental Health*, 12:43; U.S. EPA 2009 (cited above).

[10] Ostro B, Hu J, Goldberg D, Reynolds P, Hertz A,3 Bernstein L, Kleeman M. 2016. Associations of Mortality with Long-Term Exposures to Fine and Ultrafine Particles, Species and Sources: Results from the California Teachers Study Cohort. *Environmental Health Perspectives*. June 123(6) pp 549-556.

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[12] See for example Bell ML, et. al. 2013. Evidence on vulnerability and susceptibility to health risks associated with short-term exposure to particulate matter: a systematic review and meta-analysis. *American Journal of Epidemiology.* 178:865-876.; Brody JG, et. al. 2009. Linking exposure assessment science with policy objectives for environmental justice and breast cancer Advocacy: The Northern California Household Exposure Study. *American Journal of Public Health.* 99(S3): S600– S609. DOI: 10.2105/AJPH.2008.149088; Morello-Frosch R, Zuk M, Jerrett M, Shamasunder B, Kyle AD. 2011. Understanding the cumulative impacts of inequalities In environmental health: Implications for Policy. *Health Affairs*. 30:879–887; Milet M, Tran S, Eatherton M, Flattery J, Kreutzer R. 2007. The Burden of Asthma in California: A surveillance Report Richmond, CA. California Department of Health Services, Environmental Health Investigations Branch; Clark-Reyna SE, Grineski SE, Collins TW. 2016. Health status and residential exposure to air toxics. *Family & Community Health* 39:3160-168. Online publication date: Jan 1, 2016.

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Linking Exposure Assessment Science With Policy Objectives for Environmental Justice and Breast Cancer Advocacy: The Northern California Household Exposure Study

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Objectives. We compared an urban fence-line community (neighboring an oil refinery) and a nonindustrial community in an exposure study focusing on pollutants of interest with respect to breast cancer and environmental justice.

Methods. We analyzed indoor and outdoor air from 40 homes in industrial Richmond, California, and 10 in rural Bolinas, California, for 153 compounds, including particulates and endocrine disruptors.

Results. Eighty compounds were detected outdoors in Richmond and 60 in Bolinas; Richmond concentrations were generally higher. Richmond's vanadium and nickel levels indicated effects of heavy oil combustion from oil refining and shipping; these levels were among the state's highest. In nearly half of Richmond homes, $PM_{2.5}$ exceeded California's annual ambient air quality standard. Paired outdoor–indoor measurements were significantly correlated for industry- and traffic-related $PM_{2.5}$, polycyclic aromatic hydrocarbons, elemental carbon, metals, and sulfates ($r=0.54–0.92$, $P<.001$).

Conclusions. Indoor air quality is an important indicator of the cumulative impact of outdoor emissions in fence-line communities. Policies based on outdoor monitoring alone add to environmental injustice concerns in communities that host polluters. Community-based participatory exposure research can contribute to science and stimulate and inform action on the part of community residents and policymakers. (*Am J Public Health.* 2009;99:S600–S609. doi: 10.2105/AJPH.2008.149088)

With a sprawling oil refinery in the background, Marleen Quint, Wanna Wright, and Etta Lundy stood on a hill overlooking Richmond, California, holding up a photograph of Quint's mastectomy scars.[1] The women were propelled by their breast cancer diagnoses to ask whether their own cancers as well as neighborhood problems with asthma, sore throats, rashes, other cancers, and children's development were related to chemical exposures from nearby industry and rail, truck, and marine shipping corridors. Their question is part of an emerging crossover of interests between environmental justice and breast cancer advocacy[2–5] that is driven not only by personal experiences but also by breast cancer statistics for ethnic minority women; environmental hypotheses that link the same pollutants to breast cancer and to health issues of concern in low-income, minority communities; and new partnerships between communities and scientists.[6–9]

In the United States, the breast cancer incidence rate is higher among African American women younger than 40 years than among White women in the same age group,[10,11] and mortality rates among African American women are higher in all age groups, even when access to mammography and treatment are equivalent.[12] Among older women, the incidence rate is lower in the African American population than in the White population,[11] but the gap may be closing.[13,14] Meanwhile, incidence rates are rising rapidly among US immigrants[15–17] and in industrializing nations.[18]

Environmental chemical pollutants hypothesized to cause breast cancer include some that have been associated with higher breast cancer risk in several human studies, for example polycyclic aromatic hydrocarbons (PAHs) and polychlorinated biphenyls (PCBs); animal mammary gland carcinogens, including PAHs, pesticides such as chlorothalonil, and flame retardants such as tris(2,3-dibromo-1-propyl) phosphate; and endocrine-disrupting compounds (EDCs), including bisphenol A, alkylphenols, phthalates, and pesticides such as dichlorodiphenyltrichloroethane (DDT) and pyrethroids.[19–21] Thus, the chemicals of interest in breast cancer research include urban air pollutants, industrial chemicals, and pesticides to which low-income, minority populations are disproportionately exposed.[6,22] Such exposures are also hypothesized to affect health outcomes such as premature puberty, asthma, obesity, and cognitive development that disproportionately affect low-income, minority populations.[23–26]

NORTHERN CALIFORNIA HOUSEHOLD EXPOSURE STUDY COLLABORATIVE

Through the National Institute of Environmental Health Sciences environmental justice grants program, we established a community-based participatory research (CBPR) collaboration involving the Silent Spring Institute, which focuses on the environment and women's health, especially breast cancer[27]; Communities for a Better Environment (CBE), the environmental justice organization in which Quint, Wright, and Lundy are active[28]; and faculty at Brown University and the University of California, Berkeley. We addressed breast cancer and environmental justice concerns in an exposure study that expanded the Silent Spring Institute Household Exposure Study (part of the Cape Cod Breast Cancer and Environment Study)[29] to neighborhoods bordering an oil refinery in Richmond, where CBE has an active environmental justice campaign, and rural Bolinas, California, which provided a regional comparison.

We decided to conduct an exposure study because an epidemiological breast cancer study within Richmond probably would not have been informative, given the community's size and lack of relevant historical exposure measurements. An exposure study of compounds of toxicological concern can assess the extent of a problem and inform exposure reduction efforts.[30] We focused on household exposures because people spend 90% of their time indoors, often at home, and household environments have not been well characterized.[31,32] We tested for compounds hypothesized to affect breast cancer and additional products of oil combustion and refining that serve as indicators for the large number of uncharacterized emissions from oil refineries.

Our study included several goals related to policy, exposure science, and community education. Our policy goals were to provide data that would inform local decisions about the Richmond oil refinery, California state biomonitoring and chemicals policies,[33,34] and national debates regarding the use of EDCs in consumer products.

Our exposure science goals were to test for chemical markers of oil refinery emissions in homes, characterize the cumulative effects of emissions in an environmental justice community by measuring an exceptionally large and diverse set of pollutants from outdoor and indoor sources, assess geographic and sociodemographic differences in EDC exposures by comparing Cape Cod, Massachusetts, with an industrial neighborhood in California, and describe outdoor EDC levels. (An environmental justice community is composed of low-income or ethnic minority residents disproportionately affected by environmental pollution.) To our knowledge, no previous reports on these issues have been published.

Finally, one of our educational goals was to inform community members about important determinants of their indoor air quality. The other goal was to inform them about current scientific knowledge on potential relationships between indoor exposures and health, including breast cancer.

RESEARCH SETTING

To inform CBE's organizing and advocacy, we focused on the Liberty and Atchison Village neighborhoods of Richmond, in Contra Costa County: 66 acres that border a Chevron oil refinery and truck, rail, and marine shipping corridors[35] (see Figure S1, available as a supplement to the online version of this article at http://www.ajph.org). The area's uniform 1- and 2-story housing was constructed for shipyard workers during World War II. According to the 2000 census, the community was 61% Latino (many residents were monolingual Spanish speakers), 18% African American, and 3% Asian American; 26% of residents had incomes below the federal poverty level ($17 603 for a family of 4), and half had incomes below 200% of the poverty level.[36] Richmond has high cancer and respiratory risks associated with toxic industrial releases.[37] Contra Costa's 15% asthma prevalence rate is among the state's highest,[38] and its breast cancer incidence rate is higher than the statewide rate.[39] These statistics highlight Richmond's enhanced vulnerability to multiple pollutant exposures.

The Richmond Chevron refinery is one of the nation's largest, covering 2900 acres and processing more than 240 000 barrels of crude oil a day[40] into gasoline, jet fuel, diesel fuel, and lubricants. It employs approximately 1000 workers.[41] CBE was concerned about air pollution from flaring (venting and uncontrolled burning of gaseous emissions in routine operations and emergencies)[42] and about requested permit changes to replace and add equipment[43] that reportedly would increase overall throughput[44] and increase emission of sulfur dioxide, sulfates, and metals[45] through refining of lower grade crude oil with higher sulfur content.

FOCUS ON INDOOR POLLUTANTS WITH OUTDOOR SOURCES

Here, in our first report on the CBPR process and study design, we focus on results that pertain most directly to environmental justice. We describe the compounds detected (as an indication of cumulative impact) and pollutants with significant outdoor sources, as evidenced by higher outdoor concentrations in industrial Richmond than in rural Bolinas. We include for comparison an indoor-source chemical (dibutyl phthalate) to demonstrate the contrast between outdoor- and indoor-source compounds.

Results of additional analyses focusing on indoor-source chemicals, many of which are EDCs, will be published in a subsequent article, and analyses of questionnaire responses and refinery emergency releases as predictors of pollutant levels are under way. We previously reported dramatic geographic differences in brominated flame retardants (polybrominated diphenyl ethers), with the higher levels observed in California than other areas probably due to the state's strict furniture flammability standard.[46] We have written elsewhere about our methods for reporting personal exposure results to participants.[47,48]

METHODS

After a CBPR collaborative process[49,50] designed to consider what data would address mutual goals of the project partners, we sampled air and dust from 40 homes in Richmond and 10 in Bolinas, as well as outdoor air near each home. Samples were analyzed for industrial and traffic pollutants, such as particulates, metals, PAHs, ammonia, and sulfates, and for many EDCs, including pesticides, flame retardants, phthalates, and phenols.

CBPR Strategy

We gathered information on community health concerns, drew on CBE's relationships with public officials, held annual community meetings, and convened an advisory council that included neighborhood activists, breast cancer and biomonitoring activists, a state health official, and an academic researcher. On the basis of this input, we designed research to assess the cumulative effects and specific sources of indoor pollution originating from outdoor emissions.

The advisory council requested a comparison with rural northern California that would supplement the comparison with Cape Cod and maximize the contrast for assessing the cumulative impact of Richmond outdoor emissions. This request led to an additional community partnership with the Commonweal Biomonitoring Resource Center in Bolinas,[51] a nonindustrial coastal community. We deliberated how our results would affect refinery expansion plans. We expected to detect compounds associated with oil refining in Richmond homes; however, we were mindful that if we did not, our results might undermine CBE's refinery campaign, even though any negative findings might be due to inadequacies in our methods.

The research protocol was approved by Brown University's institutional review board in a novel agreement that covered both academic and community-based researchers, representing a significant accomplishment for our collaborative. Traditionally, university institutional review boards do not cover outside organizations, leaving community groups with the expense of contracting with an independent review board and diminishing the academic–community partnership. All individuals with access to personally identifiable data were formally trained with respect to ethics in human subjects research.

Selection of Households for Sampling

Balancing the goals of collecting representative neighborhood data and creating opportunities to involve CBE members, we recruited 40 nonsmoking households in the Atchison Village and Liberty neighborhoods of Richmond through door knocks at randomly selected addresses (22 participants) and announcements at community meetings (18 participants). We obtained a list of all 550 eligible residential addresses from the county tax assessor's office and the management of the Liberty Village Apartments. We mailed a letter describing the study in English and Spanish to each home.

Using a randomized address list, a CBE researcher approached 132 nonvacant residences, contacting a resident at 74 (56%); 31% of contacted eligible homes participated. Six residents agreed but could not be scheduled, 3 were ineligible, and 43 declined; we were unable to contact 58 residents. We used snowball sampling to recruit 10 participants in Bolinas; the sample size was constrained by costs (for a chart of the sampling procedure, see Figure S2, available as a supplement to the online version of this article at http://www.ajph.org).

Data Collection and Chemical Analysis

CBE staff were equipped and trained to collect samples and conduct interviews. Samples were collected between June and October 2006. EDC indoor sampling and analytical methods have been described elsewhere.[29] Paired indoor and outdoor air samplers collected parallel 24-hour integrated samples. University Research Glassware (Chapel Hill, NC) personal pesticide samplers (polyurethane foam plus sorbent XAD2) were used to collect semivolatile compounds at a flow rate of approximately 8 L per minute (as described by Rudel et al.[29]). For the 42 homes sampled between August and October 2006, respirable particulate ($PM_{2.5}$, particulate matter less than 2.5 microns in diameter) samples were also collected at a flow rate of approximately 5 L per minute on Teflon filters alongside the semivolatile sampler attached to the same high-volume pump. A parallel sample was collected on a quartz filter for carbon fractions and water-soluble ions.[52,53] Field blanks and duplicate samples were collected for quality assurance and quality control purposes.

A researcher observed characteristics of the home, including room size, open and closed windows, and rugs and carpets, and interviewed participants about demographic characteristics, consumer product use, and expectations about the study. The Southwest Research Institute (San Antonio, TX) and the Desert Research Institute (Las Vegas, NV) analyzed the samples for 153 analytes, including phthalates, alkylphenols, other phenols, parabens, banned and contemporary-use pesticides, PAHs, polybrominated diphenyl ethers, PCBs, particulates, metals, water-soluble ions, carbon fractions, and ammonia.

We obtained 24-hour integrated measurements from all 15 California Environmental Protection Agency monitors where $PM_{2.5}$ speciation data were gathered during the time of our data collection[54] (Figure S3 shows monitor locations, available as a supplement to the online version of the article at http://www.ajph.org). Comparison data from state monitors were available for $PM_{2.5}$, elemental and organic carbon, sulfates, nitrates, and metals. We selected $PM_{2.5}$, elemental and organic carbon, sulfates, vanadium, nickel, and sodium for comparison because they are indicators of specific emission source categories. We calculated summary measures for August through October 2006.

Data Analysis

In addition to comparing Richmond data and Bolinas data, we compared outdoor measurements with indoor measurements and with state monitors. For each analyte, the method reporting limit was defined as the maximum of the analytical detection limit and the 90th percentile of the field blank concentrations. Values below the method reporting limit were not included in the percentage detected but were treated as estimated values to allow visualization of distributions (e.g., in box plots) and comparison of medians. We used the Fisher exact test to evaluate differences in the numbers of compounds detected between Richmond and Bolinas and the Wilcoxon rank-sum test to assess differences in pollutant levels.

To address environmental justice concerns about outdoor emissions sources in Richmond, we evaluated the contribution of outdoor sources to indoor pollution by comparing outdoor with indoor concentrations and calculating Spearman rank correlations between outdoor and indoor levels for compounds that had higher concentrations or were more frequently detected in Richmond outdoor air than in Bolinas outdoor air. For these compounds, measured or estimated values were available for at least 70% of indoor–outdoor pairs. The level of statistical significance was set at $P<.05$.

RESULTS

Participants were predominantly middle-aged women. With respect to race/ethnicity (participants were allowed to select more than one option), 41% of the participants in Richmond self-identified as Hispanic, 54% self-identified as White, and 11% selected another race/ethnicity; 38% were interviewed in Spanish. In Bolinas, none of the participants were Hispanic, 80% were White, and 40% selected another race/ethnicity. In Richmond, 37% had a college education, as compared with 100% in Bolinas (see Table S1, available as a supplement to the online version of the article at http://www.ajph.org).

Cumulative Effects

Chemical exposures in Richmond were greater than those in Bolinas. We detected 80 compounds in Richmond outdoor air and 60 in Bolinas outdoor air. Differences in indoor air were more pronounced, with 104 compounds detected in Richmond and 69 in Bolinas (detection frequencies are shown in Table S2, available as a supplement to the online version of the article at http://www.ajph.org). In the case of the 56 compounds detected in both communities, outdoor levels were significantly higher for 33 in Richmond and 1 (diethyl phthalate) in Bolinas (Wilcoxon $P\leq.05$). Median and maximum concentrations of these 33 compounds are shown in Table 1.[52,55–62] Richmond outdoor levels were significantly

TABLE 1—Outdoor and Indoor Air Concentrations ($\mu g/m^3$) and Correlations for Compounds Detected at Higher Levels in Richmond Than in Bolinas, CA: 2006

Chemical	Outdoor Air				Indoor Air				Outdoor–Indoor Correlation[a]: Richmond
	Richmond		Bolinas		Richmond		Bolinas		
	Median	Maximum	Median	Maximum	Median	Maximum	Median	Maximum	
Particulate matter and related carbon fractions[d]									
$PM_{2.5}$	10	17	5.5	9.5	11	28	7.1	18	0.54*
Elemental carbon fraction 1	0.32	0.85	0.11	0.47	0.56	2.1	0.35	1.8	0.52*
Elemental carbon fraction 2	0.15	0.57	<MRL	0.45	0.23	0.70	0.088	0.46	0.78*
Total elemental carbon	0.35	0.94	0.067	0.63	0.54	1.6	0.20	0.95	0.58*
Organic carbon fraction 1	<MRL	0.79	<MRL	1.1	2.1	6.3	1.8	3.5	0.03
Organic carbon fraction 2	0.88	1.9	<MRL	1.4	3.4	5.2	2.6	6.5	0.20
Organic carbon fraction 3	0.87	1.9	0.55	1.2	3.2	8.0	2.8	9.0	<0.01
Organic carbon fraction 4	0.32	0.77	0.11	0.61	1.1	2.9	0.87	2.3	0.01
Total organic carbon	2.1	4.8	<MRL	4.7	10	17	8.3	22	0.08
Total carbon	2.7	5.7	<MRL	5.3	11	19	8.5	23	0.14
Metals and ions[e]									
Aluminum	0.021	0.090	0.0092	0.086	0.023	0.11	0.030	0.25	0.50*
Calcium	0.090	0.37	<MRL	0.053	0.093	0.28	0.045	0.11	0.81*
Copper	<MRL	0.055	<MRL	0.0094	<MRL	0.054	<MRL	0.023	0.05
Iron	0.063	0.24	<MRL	0.034	0.055	0.32	0.028	0.15	0.79*
Lead	0.0010	0.0040	<MRL	0.0017	0.0012	0.0041	<MRL	0.0015	0.62*
Manganese	0.0020	0.0080	<MRL	0.0012	0.0015	0.0062	0.0013	0.0030	0.78*
Nitrates	1.0	3.2	0.34	0.84	0.95	3.3	0.25	1.1	0.62*
Potassium	0.051	0.11	0.018	0.062	0.050	0.21	0.033	0.11	0.46*
Sulfates	2.2	3.9	1.3	2.5	1.6	3.6	1.4	3.4	0.91*
Vanadium	0.0050	0.023	0.0018	0.0028	0.0035	0.020	0.0016	0.0023	0.93*
Polycyclic aromatic hydrocarbons[f]									
1-methylphenanthrene	0.00042	0.0010	<MRL	0.00068	0.0013	0.0041	0.0010	0.0030	0.17
2-methylphenanthrene	0.00076	0.0020	<MRL	0.0012	0.0021	0.0060	0.0015	0.0047	0.30
3-methylphenanthrene	0.00069	0.0020	<MRL	0.0012	0.0019	0.0066	0.0017	0.0048	0.27
9-ethylphenanthrene	0.00034	0.00091	<MRL	0.00046	0.0013	0.0043	0.0012	0.0032	0.27
Acenaphthene	0.0048	0.011	0.00081	0.0046	0.0061	0.029	0.0034	0.0089	0.57*
Fluoranthene	0.0010	0.0027	<MRL	0.0038	0.00098	0.012	0.00068	0.0015	0.49*
Fluorene	0.0055	0.011	0.0011	0.0056	0.0081	0.028	0.0052	0.012	0.54*
Phenanthrene	0.0086	0.017	0.0022	0.015	0.012	0.044	0.0097	0.018	0.48*
Pyrene	0.00063	0.0019	<MRL	0.0019	0.00090	0.028	0.00071	0.00097	0.22
Phthalates[g]									
Bis(2-ethylhexyl) adipate	0.0023	0.0087	0.0015	0.0021	0.032	0.075	0.023	0.069	0.13
Bis(2-ethylhexyl) phthalate	0.017	0.24	<MRL	0.024	0.079	0.21	0.056	0.11	−0.02
Other									
Ammonia[b]	3.0	32	0.67	2.0	24	180	7.9	32	0.03
O-phenylphenol[c]	0.0012	0.0048	0.00052	0.0010	0.0083	0.061	0.013	0.019	−0.04

Note. MRL = method reporting limit (defined as the maximum of the analytical detection limit and the 90th percentile of the field blanks. Estimated values (i.e., quantified by the laboratory but below the MRL) were used in the calculation of summary statistics. Sources listed for each chemical class are based on cited literature and not specifically characterized in this study. Included are compounds measured at significantly ($P \leq .05$; Wilcoxon rank-sum test) higher concentrations in Richmond outdoor air than in Bolinas outdoor air.

[a] Spearman rank correlation coefficients.

[b] Sources: petroleum refining, agricultural activity, human and pet metabolic processes, and household cleaning products.[57,58]

[c] Sources: pesticides, disinfectants, preservatives, and other uncharacterized sources.[60,62]

[d] Sources: combustion sources including traffic, home heating, cigarette smoke, cooking, and candle burning.[52,55,56]

[e] Sources: petroleum refining, shipping, power generation, and other industrial activity; traffic; and crustal/soil.[52]

[f] Sources: combustion sources including traffic, power generation, home heating, cigarette and incense smoke, and cooking.[59]

[g] Sources: plastics, consumer products including cosmetics and pesticides, and other uncharacterized sources.[60,61]

*$P \leq .05$.

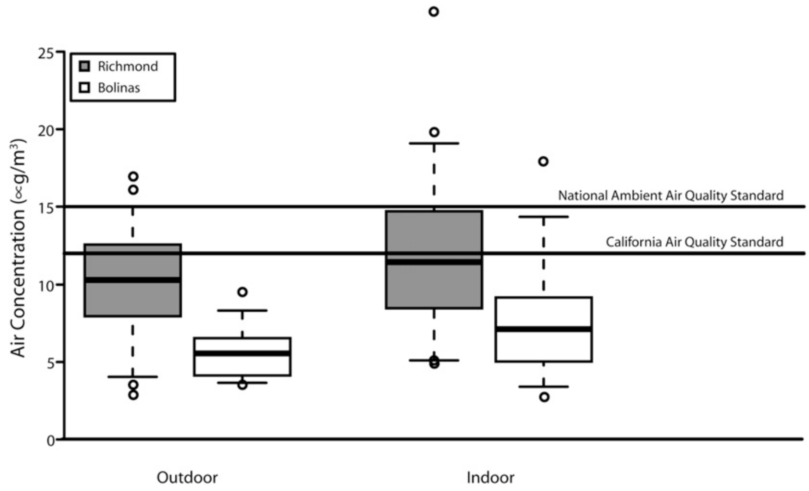
higher for refinery-related sulfates, vanadium, and ammonia and other industry- and transportation-related pollutants, including $PM_{2.5}$, PAHs, carbon fractions, and metals. Outdoor levels of 2 phthalates and *o*-phenylphenol were also significantly higher in Richmond (detailed results for EDCs will be published in an upcoming article).

Indoor air in nearly half of Richmond homes exceeded California's annual ambient air quality standard for $PM_{2.5}$, often considered an aggregate measure of air pollution; indoor levels were higher than outdoor levels in both communities (Figure 1). EDCs were detected more frequently indoors than outdoors in both communities.

Indoor Penetration of Outdoor Pollutants

To examine the impact of outdoor pollutant emissions on indoor air, we evaluated relationships between paired outdoor and indoor measurements for the 33 chemicals measured at higher levels outdoors in Richmond. Figure 2 illustrates outdoor and indoor concentrations for an example outdoor-source and an example indoor-source pollutant. In the case of sulfates, a frequent by-product of industrial pollution with few indoor sources (Figure 2ab), there was a strong correlation ($r=0.92$; $P<.001$) between paired outdoor and indoor measurements, and outdoor concentrations were consistently higher than indoor concentrations, indicating that outdoor sulfates were penetrating indoors. Strong correlations between outdoor and indoor concentrations were observed for vanadium, selenium, calcium, iron, and manganese (Spearman ρ range: 0.7–0.9; $P<.001$), and outdoor concentrations were higher than indoor concentrations.

Outdoor–indoor levels and correlations for $PM_{2.5}$, many of the PAHs (e.g., acenaphthene, fluorene, and fluoranthene), lanthanum, and elemental carbon (Spearman ρ range: 0.4–0.6; $P<.05$) suggested both outdoor and indoor sources and indicated that outdoor air is an important source of these pollutants indoors. By contrast, there were high indoor levels of di-*n*-butyl phthalate, commonly found in personal care products, and a lack of correlation between paired outdoor and indoor measurements, indicating that indoor sources dominate (Figure 2cd). A similar pattern was observed for other EDCs, including bis(2-ethylhexyl) phthalate, bis(2-ethylhexyl) adipate, and *o*-phenylphenol, and for organic carbon fractions, ammonia, and some PAHs (e.g., pyrene and methylphenanthrenes).



Note. Solid lines are medians; boxes are interquartile ranges; vertical lines are 5th and 95th percentiles; circles are extreme data points below the 5th percentile and above the 95th percentile; and horizontal dotted lines represent annual federal and state ambient air quality standards for $PM_{2.5}$.

FIGURE 1—Levels of fine particulate matter ($PM_{2.5}$) in homes in Richmond and Bolinas, CA: 2006.

Comparison With State Monitors

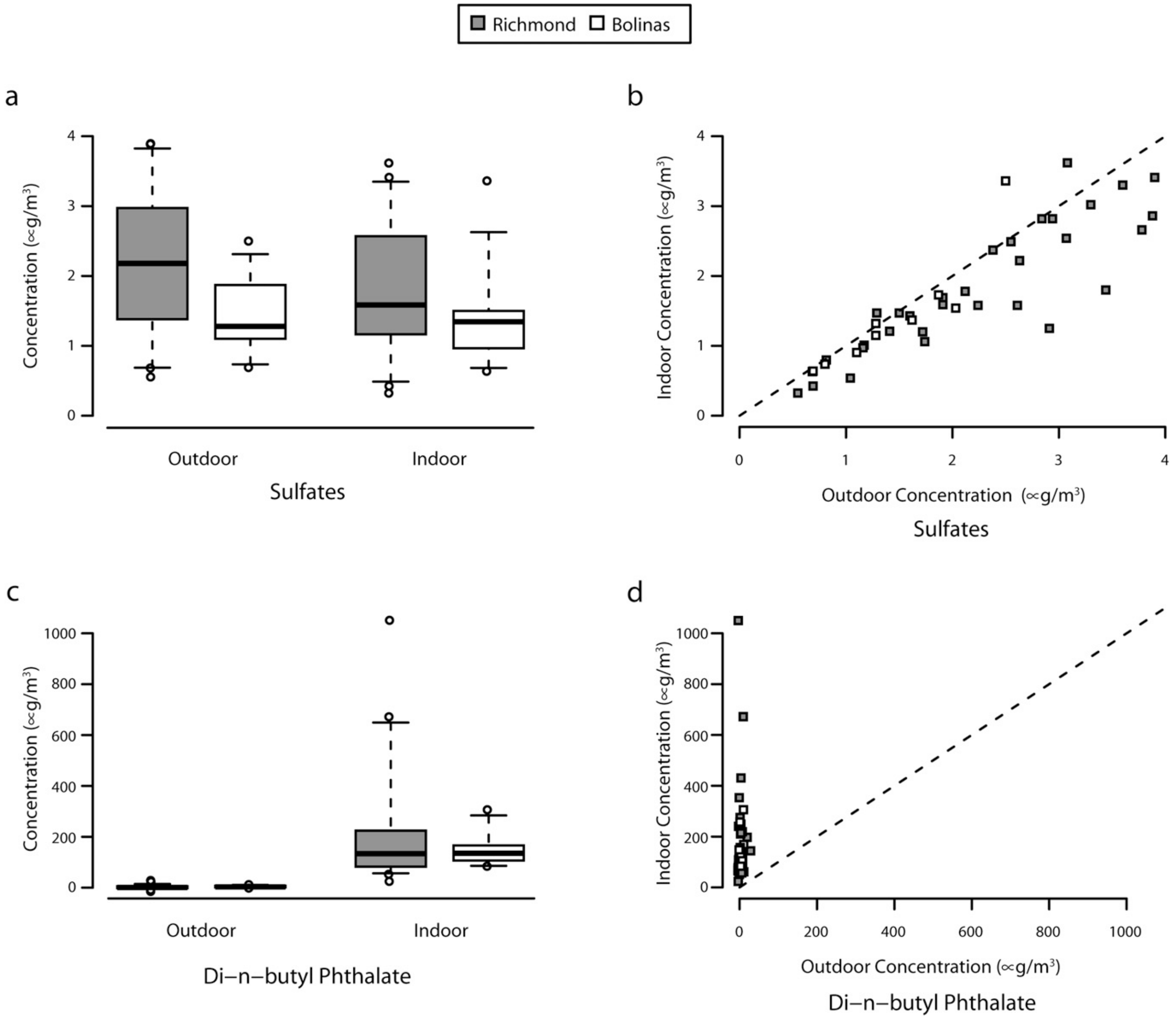
In another approach to analyzing the influence of local and regional outdoor sources, we compared outdoor measurements in Richmond and Bolinas with California Environmental Protection Agency monitoring data for the same time period as our study. For vanadium and nickel (which are markers of heavy oil combustion, especially from oil refineries and marine ports[52,63,64]), Richmond was near the top of the distribution, with the second-highest 95th percentile concentration. For sulfates, which tend to be influenced by both regional and local sources, including power plants, automobiles, and oil refineries, Richmond levels were in the top third.

In the case of pollutants such as $PM_{2.5}$, elemental and organic carbon, and nitrates deriving primarily from mobile sources, Richmond was in the lower half of the distribution. For sodium, a marker of ocean air, Richmond levels were among the highest of all monitoring sites. In Bolinas, levels for all pollutants were low, whereas sodium levels were comparable to those in Richmond. Results for vanadium, nickel, $PM_{2.5}$, and sulfates are shown in Figure 3, ordered according to 95th percentile concentrations.

DISCUSSION

Our results provide evidence regarding 3 important environmental justice concerns: the character and magnitude of cumulative exposures in urban fence-line communities (communities that neighbor polluting facilities), the limitations of outdoor ambient monitoring as an indicator of personal exposure, and the impact of specific local sources on air quality in proximate neighborhoods. As expected, more pollutants and higher outdoor concentrations were detected in Richmond than in Bolinas. Heavy oil combustion was a more prominent factor than traffic in differences between the 2 communities. Despite high traffic in Richmond, outdoor concentrations of $PM_{2.5}$ and traffic-related pollutants were in the low half of the range reported by state monitors, perhaps as a result of meteorological effects of the study neighborhood's proximity to the coast.

By contrast, Richmond levels of nickel and vanadium (known to come from heavy oil combustion, especially in refinery operations



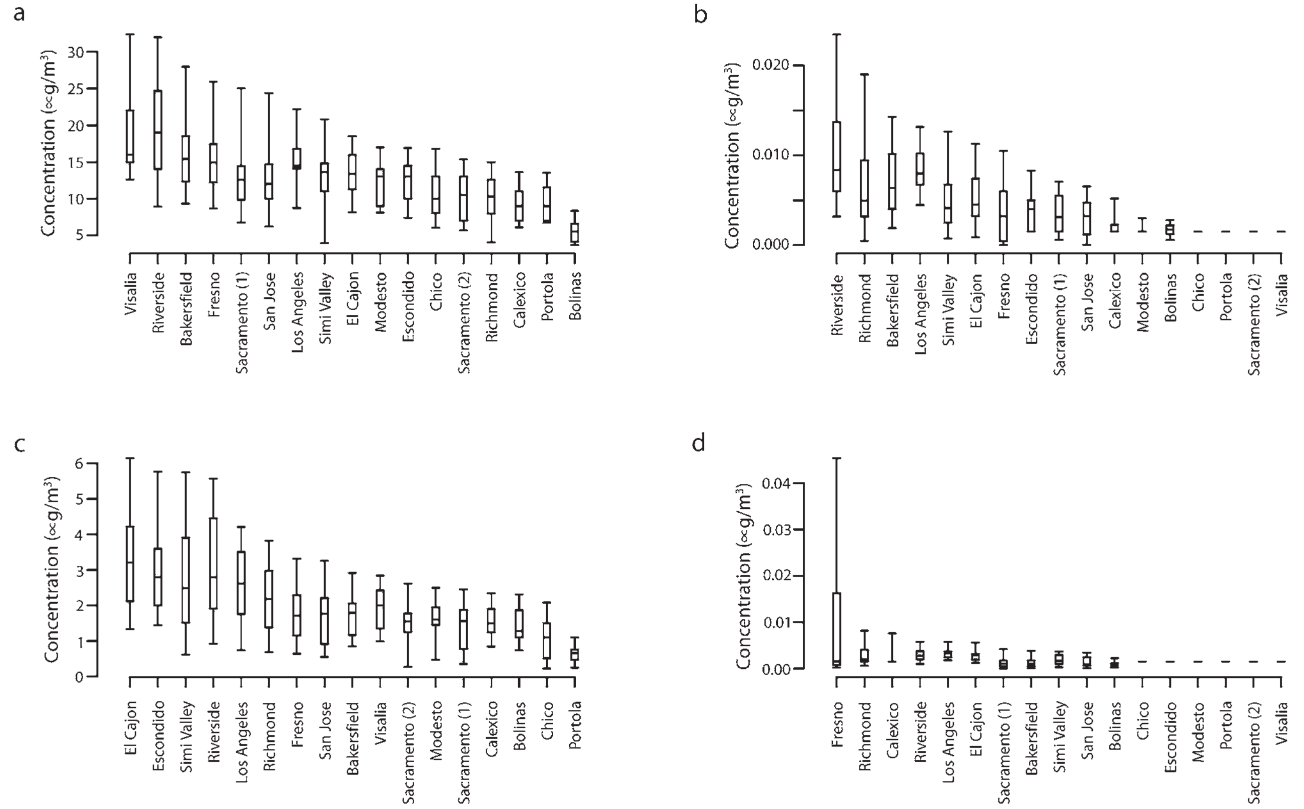
Note. Panels a and c are box plots comparing distributions for sulfates and di-*n*-butyl phthalate, respectively. Panels b and d show the correlations between indoor and outdoor concentrations across both communities. The dotted line represents 1:1.

FIGURE 2—Relationships between (a) sulfates, (b) indoor and outdoor concentrations of sulfates, (c) di-*n*-butyl phthalate, and (d) indoor and outdoor concentrations in di-*n*-butyl phthalate: Richmond and Bolinas, CA, 2006.

and marine shipping) were among the highest in the state. These compounds, along with sulfates (also associated with refineries), penetrated into Richmond homes, as demonstrated by correlations between outdoor and indoor concentrations. Health studies have shown that sulfates, nickel, and vanadium are some of the most harmful $PM_{2.5}$ components.[65,66] Furthermore, these compounds are indicators of probable exposures to hundreds of unmeasured compounds given that refinery emissions are complex and poorly characterized.[67,68]

The significant correlations we observed between outdoor and indoor levels of $PM_{2.5}$, sulfates, and other pollutants are consistent with the results of other studies showing that outdoor air pollution is an important determinant of indoor exposures.[31,59,69,70] The finding that local outdoor emissions penetrate indoors bears directly on Richmond refinery permits for activities that increase or decrease outdoor emissions, and our observations have implications for facility reviews elsewhere as well.

The much higher levels of pollutants indoors than outdoors indicate that traditional environmental impact assessments based on outdoor air quality are inadequate to represent personal exposures. California's ambient air quality standard is not intended to be applied to indoor air; however, it is of concern that



Note. Monitor locations are ranked according to the 95th percentile concentration in order of highest to lowest from left to right. Solid lines are medians; boxes are interquartile ranges; and vertical lines are 5th and 95th percentiles.

FIGURE 3—Comparison of study site outdoor air pollution levels in Richmond and Bolinas, CA, with California state monitors, 2006.

nearly half of Richmond homes exceeded this standard for $PM_{2.5}$ during the summer, when outdoor $PM_{2.5}$ levels are markedly lower than in winter. Epidemiological studies have consistently linked this pollutant to respiratory and cardiovascular problems, including premature death.[71] In addition, the PAHs and other compounds we detected may be associated with breast cancer.[20,21] Socioeconomic stressors in Richmond may amplify the detrimental health effects of chemicals we observed.[8,72]

Our results also have implications for policies concerning EDCs in consumer products. Outdoor levels were lower than and not correlated with indoor levels for chemicals coming primarily from consumer products, such as di-*n*-butyl phthalate. We observed few differences in EDC levels between our 2 markedly different communities. These results suggest that consumer products contribute substantially to indoor air quality and indicate the need for state or national remedies, such as the efforts of breast cancer organizations to secure proactive chemical policies and launch consumer campaigns to reduce the use of EDCs.[73,74]

Limitations of our study include the small number of homes sampled in Bolinas. Also, as a result of financial constraints, we sampled each home only once. Multiseason sampling would better characterize long-term, typical exposures and capture higher wintertime $PM_{2.5}$ levels. We were unable to collect samples directly representing emissions from refineries or other sources to compare with household contaminant profiles. In addition, although our study focused on a poor, largely Latino community, members of racial/ethnic minority groups and less educated residents were underrepresented in our sample. Finally, given the large number of comparisons of individual chemicals, some of our findings may be attributable to chance.

The strengths of the study include the use of a standard protocol in Richmond and Bolinas, the inclusion of paired indoor and outdoor samples and a broad range of analytes, comparability with state monitoring data, collaboration between diverse academic and community partners, and attention to individual and community communications regarding the study. Unlike environmental justice investigations of industrial and transportation pollution that typically rely on ambient air monitoring or facility emissions data, we collected unique local data on personal exposures in the home.

Public Health Applications

During our study, refinery permit changes were proposed that could increase harmful pollutant emissions[45] in Richmond via the refining of higher sulfur crude oil. CBE mobilized testimony against the plan before the Richmond Planning Commission and the city council, urging them to consider the existing cumulative pollutant burdens documented in our study. News stories highlighted our results,[75,76] and city council members asked us to testify.[77] Study participants used their individual data and aggregate results in their own testimony, vividly demonstrating how our study helped activate and expand community engagement in environmental justice issues. At community meetings, discussions spontaneously turned to ways to use results to negotiate health protections from the oil company.

Testimony and media coverage of our findings led the Richmond Planning Commission to attempt to restrict high-sulfur crude oil refining. However, as gasoline prices climbed and the company offered Richmond $60 million in mitigation benefits, the city council reversed the planning commission's recommendation and approved the Chevron proposal in July 2008.[44] Thus, although our study influenced deliberations, the company's socioeconomic and political muscle in this cash-strapped city wielded a stronger influence. Later, the November 2008 election of new council members changed the balance again, and Richmond residents also passed a ballot measure that would require Chevron to pay the city an annual business license fee estimated at $26.5 million.

Although we cannot yet assess the significance of this study for CBE, we now have empirical results to support concerns about the effects of refinery emissions, and we know that CBE valued the study's process. As CBE staff conducted interviews and set up sampling equipment, the study helped demystify science by moving the data-gathering process into people's homes. That experience encouraged community members to think in new ways about sources of chemicals around them. These discussions enabled CBE to connect its organizing work with technical analysis—each central to environmental justice—and may strengthen CBE's long-term organizing and advocacy capacity.

This experience illustrates the CBPR view that both scientific outcomes and the research process are important. The future of the refinery expansion continues to unfold as CBE pursues a long-term mobilization effort that includes disseminating results from our study, engaging in litigation, and conducting a health symptoms survey with other neighborhood and environmental justice groups.

Conclusions

Environmental justice assessments should consider indoor exposures from local polluters. In this study, we found that cumulative air pollution burdens were more pronounced indoors than outdoors in an urban industrial environmental justice community in comparison with a rural community. Indoor air in nearly half of the environmental justice community homes in our study exceeded the California ambient air quality standard for respirable particulates, even though the residents were nonsmokers. High levels of contaminants associated with oil refining and marine shipping were detected both outdoors and indoors. Participation in this CBPR study mobilized and supported community efforts to block permits for the neighboring oil refinery. Our results also can inform a variety of individual- and policy-level exposure reduction efforts and the design of future studies focusing on air pollutants and breast cancer and other health outcomes. ■

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Contributors

J. Green Brody, R. Morello-Frosch, P. Brown, C. Pérez, and R. A. Rudel planned and supervised the study. J. Green Brody led the writing, with substantial contributions from the other authors. A. Zota conducted the statistical analysis and reported results to participants. All of the authors helped to conceptualize ideas and review drafts of the article.

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Human Participant Protection

The research protocol was approved by Brown University's institutional review board. Participants provided informed consent prior to initiation of sample collection in their homes.

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ERRATUM

In: Brody JG, Morello-Frosch R, Zota A, Brown P, Pérez C, Rudel RA. Linking exposure assessment science with policy objectives for environmental justice and breast cancer advocacy: the Northern California Household Exposure study. *Am J Public Health.* 2009;99(S3):S600–S609. doi: 10.2105/AJPH.2008.149088.

Figures and tables were improperly edited. On page S603, Table 1 should read:

TABLE 1—Outdoor and Indoor Air Concentrations (μg/m^3) and Correlations for Compounds Detected at Higher Levels in Richmond Than in Bolinas, CA: 2006

	Outdoor Air				Indoor Air				Outdoor–Indoor Correlation[a]: Richmond
	Richmond		Bolinas		Richmond		Bolinas		
Chemical	Median	Maximum	Median	Maximum	Median	Maximum	Median	Maximum	
Particulate matter and related carbon fractions[d]									
$PM_{2.5}$	10	17	5.5	9.5	11	28	7.1	18	0.54*
Elemental carbon fraction 1	0.32	0.85	0.11	0.47	0.56	2.1	0.35	1.8	0.52*
Elemental carbon fraction 2	0.15	0.57	< MRL	0.45	0.23	0.70	0.088	0.46	0.78*
Total elemental carbon	0.35	0.94	0.067	0.63	0.54	1.6	0.20	0.95	0.58*
Organic carbon fraction 1	< MRL	0.79	< MRL	1.1	2.1	6.3	1.8	3.5	0.03
Organic carbon fraction 2	0.88	1.9	< MRL	1.4	3.4	5.2	2.6	6.5	0.20
Organic carbon fraction 3	0.87	1.9	0.55	1.2	3.2	8.0	2.8	9.0	< 0.01
Organic carbon fraction 4	0.32	0.77	0.11	0.61	1.1	2.9	0.87	2.3	0.01
Total organic carbon	2.1	4.8	< MRL	4.7	10	17	8.3	22	0.08
Total carbon	2.7	5.7	< MRL	5.3	11	19	8.5	23	0.14
Metals and ions[e]									
Aluminum	0.021	0.090	0.0092	0.086	0.023	0.11	0.030	0.25	0.50*
Calcium	0.090	0.37	< MRL	0.053	0.093	0.28	0.045	0.11	0.81*
Copper	< MRL	0.055	< MRL	0.0094	< MRL	0.054	< MRL	0.023	0.05
Iron	0.063	0.24	< MRL	0.034	0.055	0.32	0.028	0.15	0.79*
Lead	0.0010	0.0040	< MRL	0.0017	0.0012	0.0041	< MRL	0.0015	0.62*
Manganese	0.0020	0.0080	< MRL	0.0012	0.0015	0.0062	0.0013	0.0030	0.78*
Nitrates	1.0	3.2	0.34	0.84	0.95	3.3	0.25	1.1	0.62*
Potassium	0.051	0.11	0.018	0.062	0.050	0.21	0.033	0.11	0.46*
Sulfates	2.2	3.9	1.3	2.5	1.6	3.6	1.4	3.4	0.91*
Vanadium	0.0050	0.023	0.0018	0.0028	0.0035	0.020	0.0016	0.0023	0.93*
Polycyclic aromatic hydrocarbons[f]									
1-Methylphenanthrene	0.00042	0.0010	< MRL	0.00068	0.0013	0.0041	0.0010	0.0030	0.17
2-Methylphenanthrene	0.00076	0.0020	< MRL	0.0012	0.0021	0.0060	0.0015	0.0047	0.30
3-Methylphenanthrene	0.00069	0.0020	< MRL	0.0012	0.0019	0.0066	0.0017	0.0048	0.27
9-Methylphenanthrene	0.00034	0.00091	< MRL	0.00046	0.0013	0.0043	0.0012	0.0032	0.27
Acenaphthene	0.0048	0.011	0.00081	0.0046	0.0061	0.029	0.0034	0.0089	0.57*
Fluoranthene	0.0010	0.0027	< MRL	0.0038	0.00098	0.012	0.00068	0.0015	0.49*
Fluorene	0.0055	0.011	0.0011	0.0056	0.0081	0.028	0.0052	0.012	0.54*
Phenanthrene	0.0086	0.017	0.0022	0.015	0.012	0.044	0.0097	0.018	0.48*
Pyrene	0.00063	0.0019	< MRL	0.0019	0.00090	0.028	0.00071	0.00097	0.22
Phthalates[g]									
Bis(2-ethylhexyl) adipate	0.0023	0.0087	0.0015	0.0021	0.032	0.075	0.023	0.069	0.13
Bis(2-ethylhexyl) phthalate	0.017	0.24	< MRL	0.024	0.079	0.21	0.056	0.11	−0.02
Other									
Ammonia[b]	3.0	32	0.67	2.0	24	180	7.9	32	0.03
o-Phenylphenol[c]	0.0012	0.0048	0.00052	0.0010	0.0083	0.061	0.013	0.019	−0.04

Note. MRL = method reporting limit (defined as the maximum of the analytical detection limit and the 90th percentile of the field blanks. Estimated values (i.e., quantified by the laboratory but below the MRL) were used in the calculation of summary statistics. Sources listed for each chemical class are based on cited literature and not specifically characterized in this study. Included are compounds measured at significantly ($P \leq .05$; Wilcoxon rank-sum test) higher concentrations in Richmond outdoor air than in Bolinas outdoor air.

[a] Spearman rank correlation coefficients.

[b] Sources: petroleum refining, agricultural activity, human and pet metabolic processes, and household cleaning products.[57,58]

[c] Sources: pesticides, disinfectants, preservatives, and other uncharacterized sources.[60,62]

[d] Sources: combustion sources including traffic, home heating, cigarette smoke, cooking, and candle burning.[52,55,56]

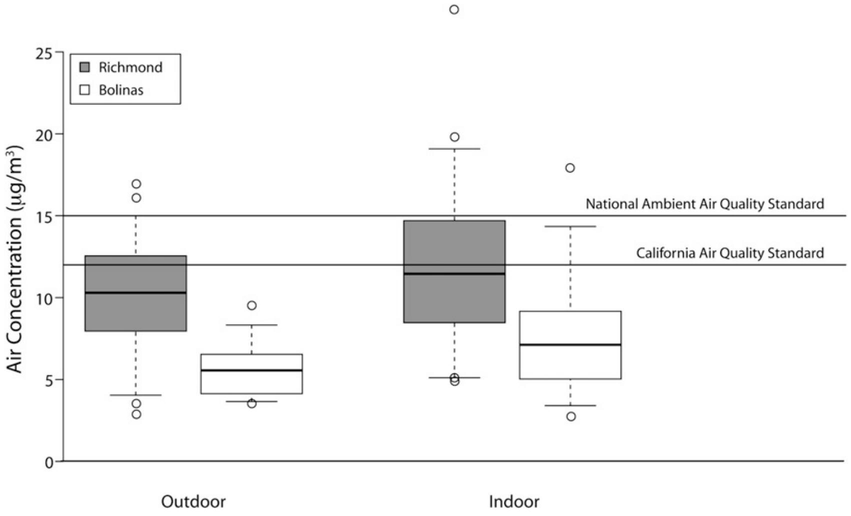
[e] Sources: petroleum refining, shipping, power generation, and other industrial activity; traffic; and crustal/soil.[52]

[f] Sources: combustion sources including traffic, power generation, home heating, cigarette and incense smoke, and cooking.[59]

[g] Sources: plastics, consumer products including cosmetics and pesticides, and other uncharacterized sources.[60,61]

*$P \leq .05$.

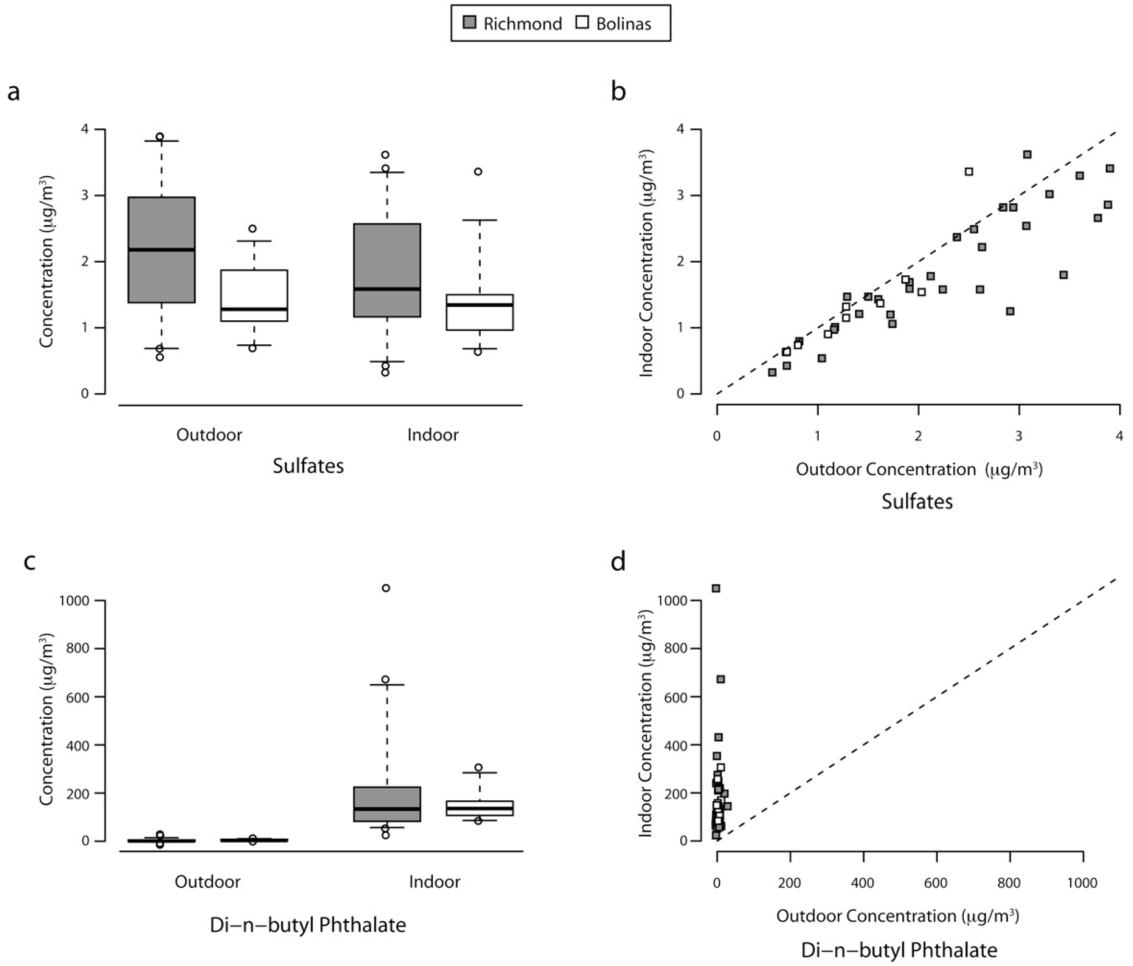
On page S604, Figure 1 should be:



Note. Solid lines are medians; boxes are interquartile ranges; vertical lines are 5th and 95th percentiles; circles are extreme data points below the 5th percentile and above the 95th percentile; and horizontal dotted lines represent annual federal and state ambient air quality standards for $PM_{2.5}$.

FIGURE 1—Levels of fine particulate matter ($PM_{2.5}$) in homes in Richmond and Bolinas, CA: 2006.

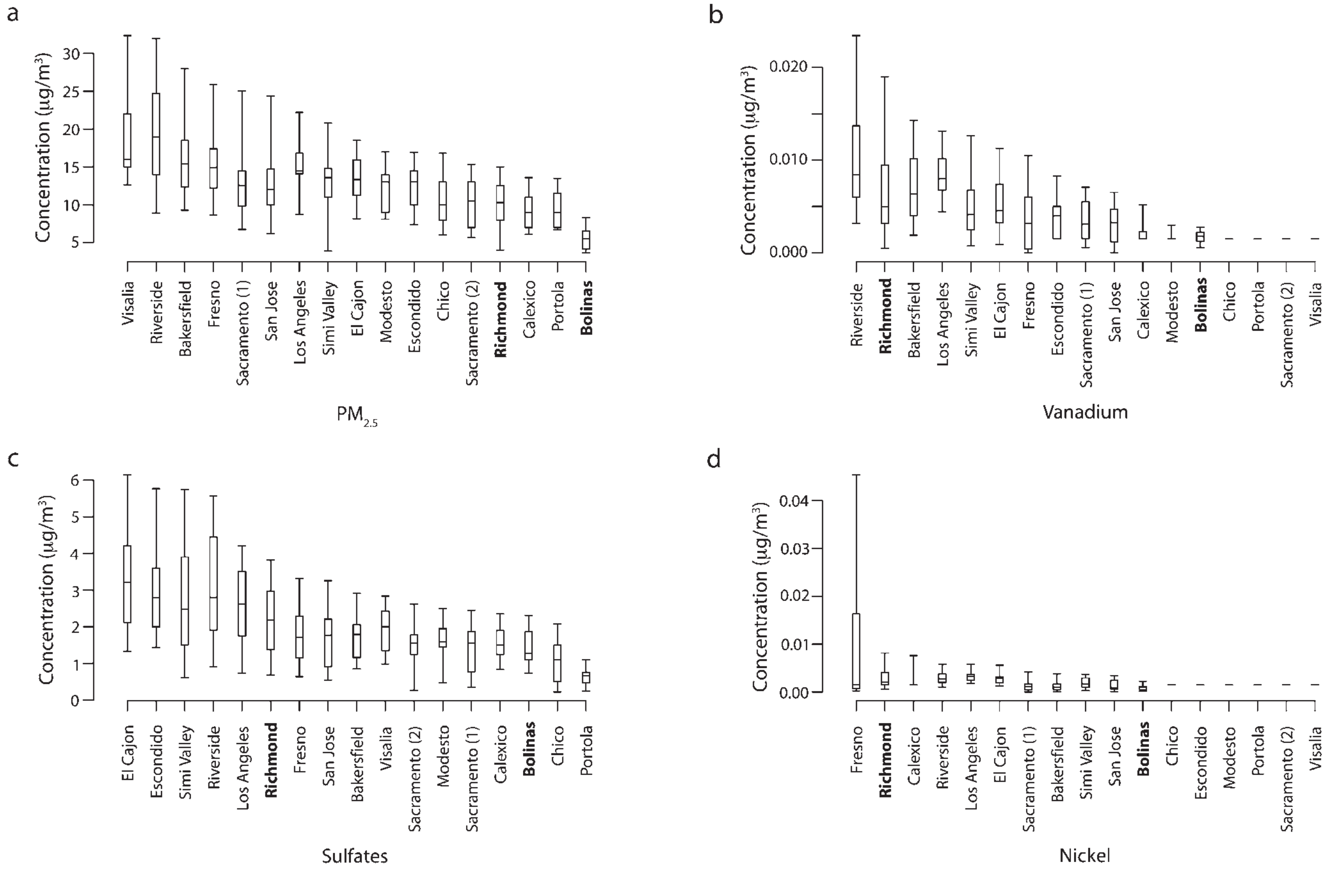
On page S605, Figure 2 should be:



Note. Panels a and c are box plots comparing distributions for sulfates and di-*n*-butyl phthalate, respectively. Panels b and d show the correlations between indoor and outdoor concentrations across both communities. The dotted line represents 1:1.

FIGURE 2—Relationships between (a) sulfates, (b) indoor and outdoor concentrations of sulfates, (c) di-*n*-butyl phthalate, and (d) indoor and outdoor concentrations in di-*n*-butyl phthalate: Richmond and Bolinas, CA, 2006.

On page S606, Figure 3 should be:



Note. Monitor locations are ranked according to the 95th percentile concentration in order of highest to lowest from left to right. Solid lines are medians; boxes are interquartile ranges; and vertical lines are 5th and 95th percentiles.

FIGURE 3—Comparison of Richmond and Bolinas, CA, with California state monitor outdoor air pollution levels of (a) $PM_{2.5}$, (b) vanadium, (c) sulfates, and (d) nickel: 2006.

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Minding the Climate Gap

What's at Stake if California's Climate Law isn't Done Right and Right Away

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Introduction

The California Global Warming Act (AB 32) – a cutting edge policy that no one expected to pass so quickly and with so much bipartisan support – proposes to cut green house gas emissions to 1990 levels by 2020. The successful implementation of such a standard would mean reducing carbon emissions from major polluters around the state – cement refineries, power plants, and oil refineries top among them. It's a clear victory for all Californians, it would seem – but the underlying picture may be a bit more complicated.

As we have shown in a recent report entitled *The Climate Gap* (Morello-Frosch, et al. 2009), climate change is not affecting all people equally: communities of color and low-income communities suffer the greatest negative health and economic consequences. Among the many disparate impacts, these communities are more vulnerable to heat incidents, more exposed to air pollution, and may be more affected by the economic dislocations of ongoing climate change.

While reducing greenhouse gas emissions will benefit all Californians, a carbon reduction system that does not take co-pollutants into account could likely result in significantly varying benefits for different populations. Those who are most likely to suffer the negative consequences of a short-sighted carbon trading system are the communities of color and the low-income communities already facing the greatest impacts of climate change – widening instead of narrowing the climate gap.

Consider the La Paloma power plant and the Exxon Mobil refinery in Torrance. The La Paloma power plant sits about 35 miles west of Bakersfield in an abandoned oil field just outside the small town of McKittrick (population 160) with less than 600 residents in the surrounding six miles, and no other facilities in the immediate vicinity. The Exxon Mobil refinery, on the other hand, is one of many facilities affecting nearly 800,000 people in the encircling six miles. While these facilities share one similarity – according to recently released 2008 GHG emissions data from the California Air Resources Board, they both emit between 2.5 and 3 million tons of carbon dioxide each year – La Paloma releases 48.6 tons of asthma and cancer causing particulate matter per year while Exxon Mobil emits 352.2 tons. This staggering health risk is important to people who live in Torrance's dense neighborhoods, yet this fact is often ignored in the debates about how we might best implement AB 32.

Why is the difference between reducing emissions at La Paloma and in Torrance overlooked in the discussion about mitigating climate change? Part of the reason is that too much of the discussion stays at the macro-level: climate change is imagined as ozone layer erosion, heat waves, and sea level rises. So while the catastrophic potential of climate change is well documented, the story of the climate gap – the often unequal impact the climate crisis has on people of color and the poor in the United States – is just starting to be told. Until recently, systemic efforts to combat climate change have focused primarily on reducing carbon with little, if any, regard for where the reductions take place and who they might affect. In this view, reducing greenhouse gas emissions – no matter where it occurs – is the central objective of policy change.

People, however, do live somewhere – and it is at the local and not the macro level where changes from new policy will be most immediately felt. When smoke stacks in low-income communities belch less carbon, they also emit less particulate matter, sulfuric oxides, and nitrous oxides. When truck operators retrofit their units to reduce emissions, children's asthma rates are likely to fall along the traffic corridors that they impact. Paying attention to the climate gap – focusing on the co-pollutants and the potential co-benefits of greenhouse gas reductions – is important for public health. And lifting this issue up can give California not only a chance to address its historic pattern of environmental inequity but also the opportunity to implement a climate change policy that will be replicated throughout the nation.

Additionally, the economic opportunity that could be realized by reducing air pollution in dense neighborhoods is also enormous. All Californians are affected by higher insurance premiums, medical costs and lost productivity due to the many illnesses caused by air pollution, and all stand to benefit from an equitable system that would work toward minimizing these costs as opposed to adding to this growing burden. Not only does it make economic sense, but the text of AB 32 itself also requires CARB in designing any market-based mechanisms for GHG reductions to consider the localized impacts in communities that are already impacted by air pollution, prevent any increase in co-pollutants, and maximize the co-benefits of co-pollutant reductions.[1]

This report seeks to analyze co-pollutants and co-benefits, with an eye toward thinking through policy designs that could help maximize public health and close the climate gap. We begin below by discussing why geographic inequality in greenhouse gas (GHG) reduction is likely under any market-based scheme and why it matters for public health. We then describe the necessary baseline for any analysis, indicating how some major facilities that emit significant GHGs – power plants, petroleum refineries, and cement plants – affect their neighbors, and who (and how many) those neighbors are. We then take on a trickier task: assessing the potential impacts of a cap-and-trade program in California. Because we cannot see into the market's future, we take a simpler approach: we identify which industries and their associated facilities are driving environmental inequity, and use this to suggest how policy-makers could take this into account in fulfilling AB 32's requirement to both reduce overall emissions *and* protect climate gap neighborhoods.

AB 32 has heralded a new era of regulatory action to reduce greenhouse gas emissions, and California finds itself once again leading the country in the area of environmental protection. As proud as we should be of that, we must be mindful that the state is deeply plagued by issues of environmental inequity, and that if our new climate change regulations are not designed to address the growing climate gap, the suffering of those who bear the brunt of this burden may grow. Numerous studies demonstrate that air pollution burdens tend to fall disproportionately on those who are the least privileged and the most vulnerable. We do not need to perpetuate and worsen this trend. Instead, we can lift up issues of public health and fair environmental policies to ensure that the implementation of AB 32 is a success for all Californians and a model for the nation and a world looking for viable paths to environmental, social and economic sustainability.

The Problem

California is at the forefront of dealing with climate change, by setting new standards, driving toward energy efficiency, encouraging renewables, and even working to rebalance the mix of land uses and transportation that have produced our well-documented sprawl. Within the context of our myriad efforts, the state has committed to the development of a "cap-and-trade" system in which GHG emissions from the facilities of certain polluting industries would be capped and emissions permits or "allowances" would be allocated (through auction, a fee, for free, or otherwise) to create a market for carbon emissions. In such a system, once the allowances are distributed for any compliance period, emitters of greenhouse gases whose emissions exceed their allowances may purchase allowances from other facilities – those who are reducing emissions beyond their own goals – rather than taking on the cost of reducing emissions from their own facilities. Another option, though highly controversial, is that they could cover their excess GHG emissions through the purchase of "offsets," which are basically projects or activities that yield a net GHG emissions reduction for which the ownership of the reduction can be transferred.

The arguments for cap-and-trade revolve around a narrow concept of industrial efficiency – if it is less costly for some firms to meet reduction goals, they should move first and fastest, and this will reduce the overall burden of compliance and perhaps speed the attainment of stricter GHG emissions targets overall (i.e. "the cap"). Some also argue that such a system could encourage technological innovation as firms seek to either buy fewer permits or chase the profit opportunities inherent in reducing their own emissions and offering their unused permits to other firms that cannot reduce as quickly. In this view, the market is being harnessed for public good, with the incentive structure providing businesses a positive reason to participate in making the intentions of AB 32 real as well as the flexibility to meet goals.

Opponents of cap-and-trade worry that enforcement of such a market system is not feasible and that the market will inevitably be gamed, leading to a sinkhole of financial resources with little regulatory oversight; opponents point to the subprime mortgage crisis and the recent economic meltdown as examples of trading markets that went haywire with little accountability. Others have noted that some experiences with cap-and-trade, as in the early implementation in the European Union, did not lead to significant GHG reductions. Still others object to program design, particularly the notions of handing out allowances *gratis* to polluting firms – something that is *de facto* a mass transfer of wealth from the general public to private polluters – and the use of offsets, which could displace actual emissions reductions in California through, for example, slowing deforestation somewhere across the globe.

While these are legitimate concerns this report explores a more limited and focused issue: whether or not implementation of cap-and-trade in California might fail to capture public health benefits, or even make an already inequitable situation worse, thereby failing to maximize the social good to the same extent that might be obtained from a different or better-designed system.

To see this, it is important to recognize that cap-and-trade is inherently unequal. The cap part is, of course, equal: everyone gains from a regional reduction in GHG and the slowdown in climate change that might be induced. But the trade part is inherently unequal – or why would anyone trade? Indeed, trading is justified on the grounds that reducing pollution is more efficient in some locations compared to others, and thus *where* reductions will occur is a decision such a system leaves in the hands of the market and businesspeople – neither of which have any incentive to lower emissions in order to benefit the low-income and minority communities hit hardest by concentrated pollution.

Some argue that the location of the emissions reduction is not important – reductions in GHG benefit the planet no matter where they occur. But since GHG emissions are usually accompanied by releases of other pollutants, there could be very different impacts on the health of residents living near plants that choose, under cap-and-trade, to either reduce emissions or purchase their way out of that requirement. Therefore, the reductions made at the lowest marginal price might be efficient in

terms of the costs and benefits to the industrial economy, but would likely be enormously inefficient in a real sense if they fail to completely account for all external costs such as health impacts. Any carbon trading plan blind to the effects of co-pollutants would be deeply flawed in ignoring significant health impacts and the associated costs, such as the economic burden that could be shifted to other sectors, such as the healthcare system.

This public health concern has been among the arguments made by members of the Environmental Justice Advisory Committee (EJAC) – a group made up of leaders representing the communities most impacted by pollution in the state and itself a product of the AB 32 legislation intended to advise the California Air Resources Board (CARB). EJAC has, among other things, been concerned that the Scoping Plan for AB 32 calls for a cap-and-trade regulatory mechanism, which on its own, has no way to ensure the protection or improvement of environmentally degraded or stressed neighborhoods.

The public health issue arises in part because while cap-and-trade tries to price in one externality – carbon and other GHG emissions – it does not price in all externalities, including the health and other impacts of co-pollutants. While quantifying such economic externalities is not our focus, Groosman et al. (2009) have found the health co-benefits alone from co-pollutant reductions due to a nationwide cap on carbon emissions *may be greater than the cost of making such reductions itself* – without even considering the large-scale benefits of slowing climate change. In a study of the co-benefits of carbon emissions reductions in the European Union, Berk et al. (2006) reached similar conclusions.

There are reasonable arguments that other regulations, such as the Clean Air Act, can tame co-pollutant emissions and that one does not want to overload a new carbon trading system. Yet it is not clear why the introduction of a whole new market in carbon trading is not in and of itself sufficiently complicated that building in a few safeguards to protect stressed communities would be the straw that breaks the regulatory camel's back. Moreover, given the well-founded skepticism of existing regulations that is held by many Environmental Justice (EJ) communities based on historical experiences, it is also not clear why the inclusion of safeguards would not make political sense as well.

Of course, whether one wants to think about such safeguards at all depends on whether or not a market system actually does have the realistic potential to introduce uneven benefits in public health – and the rest of this document is devoted to assessing whether such a scenario is possible. Thus, we need to investigate the current distribution of plants with regard to race, income and population density in order to see whether this is a concern worthy of public policy (and not just academic) consideration. Although we believe it is, we would also offer a few caveats to the case we will make.

First, some have dismissed concerns around uneven emissions reductions, arguing that because of other regulations, cap-and-trade will never produce "hot spots" – that is, places where emissions of both GHG and co-pollutants actually increase (an outcome that actually occurred in Southern California, for example, in a poorly designed system that allowed NO_x emissions trading between mobile and stationary sources, and led refineries to purchase and decommission "clunkers" rather than clean up near fenceline communities; see Drury, et al. 1999). Thus, any form of trading should meet the limited requirement in AB 32 that any market system should "prevent any increase in the emissions of toxic air contaminants or criteria air pollutants."[2]

We do think that there is a possibility of "hot spots," particularly if plants below current regulatory emissions requirements for co-pollutants might eventually be sunsetted and so operators step up production (and emissions) in the interim (just as one might run an aging appliance past its prime knowing that it will soon be replaced). This is by no means an extreme view: the potential for "hot spots" is acknowledged by some who are against imposing any sort of health- or EJ-based constraints on the cap-and-trade system. Schatzki and Stavins (2009), for example, argue for mechanisms to address EJ concerns over cap-and-trade that are external to the the sytem itself (and particularly stress the use of traditional regulations for co-pollutants) but do concur that cap-and-trade could lead to an increase in local co-pollutant emissions, even if there is a net reduction statewide. However, we do not contend that this is the most likely outcome and believe that the main problem is one of missed opportunity: that we will fail to achieve and target public health benefits from GHG reductions in the communities that need them the most.

Second, while we focus here on cap-and-trade, the concerns we raise are equally applicable to the carbon fee system proposed by some cap-and-trade opponents. Although regulatory oversight is more straightforward in a fee-based system, here too, polluters can decide whether to reduce emissions or pay to pollute. We focus on cap-and-trade because it is the primary mechanism being discussed on both the state and federal policy agendas. The issues raised here are relevant to the potential gaps left by any market-based tool – cap-and-trade, carbon fee or a hybrid – and CARB must assess the potential for market-based mechanisms to worsen existing public health disparities before it develops such a regulatory framework.

Finally, we are *not* suggesting that considering inequitable health impacts in the development of a market-based carbon reduction plan is the only (or even the most important) piece of the puzzle in addressing the “climate gap”. There are many other areas of concern – such as the economic impacts on consumers, the job opportunities for low-skill workers, the role of urban heat islands, and the nature of our logistic and social preparation for extreme weather events. Still, we think that the public health piece is an important component within a larger climate justice debate.

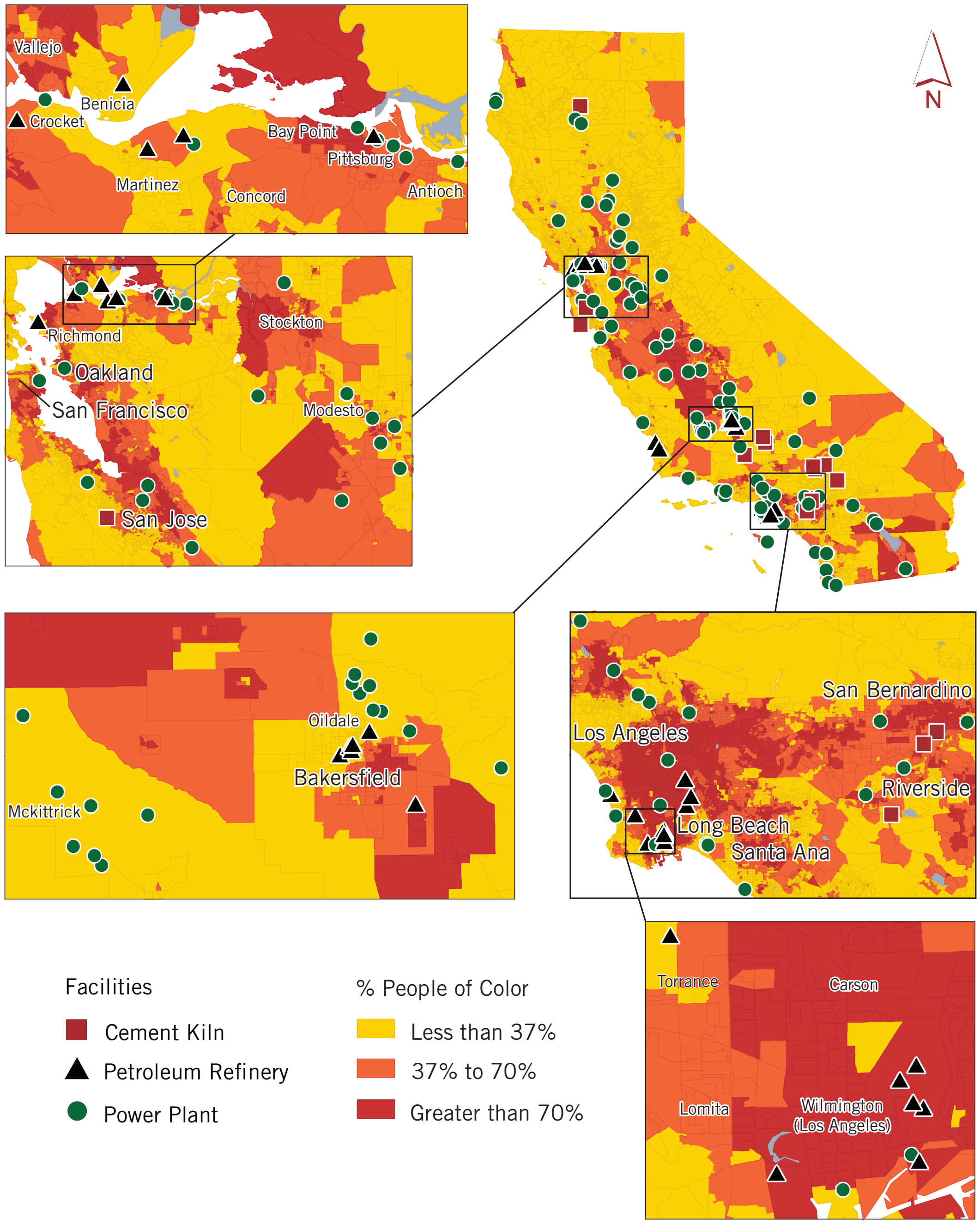
The Data

To connect climate change indicators with neighborhood disparities, we combined several data sources. We specifically performed GIS spatial analysis using demographic and emissions data, working down to detailed neighborhood measures needed to understand local health impacts.

Following a method developed by the Natural Resources Defense Council (NRDC) (Bailey et al. 2008), we pulled together emissions data on industries that are known to emit large quantities of CO_2 – petroleum refineries, cement plants, and power plants.[3] Together, the facilities included in our analysis from these sectors account for about 20 percent of the state’s GHG emissions and will be the first group to come under regulation. We extracted data from two sources: the 2006 CARB Emissions Inventory[4] for information on co-pollutants (NO_x and PM_{10}) and the 2008 GHG emission from CARB’s first annual release under the state’s mandatory GHG Reporting Program.[5] The power plant data only includes those oil and natural gas plants who reported to the California Energy Commission (CEC) in 2007 that they produced at least 50 online megawatts, and all other plants that may not have met that criteria but were either coal-fired or among the top 20 polluters of nitrous oxides (NO_x), particulate matter (PM_{10}), or carbon dioxide equivalent (CO2e). Petroleum refineries and cement plants data are from 2006, and the resulting overall dataset includes 146 facilities, once restricted to those for which co-pollutant emissions information could be obtained from a total of 154 facilities considered. This set of facilities overlaid on racial demographics can be seen in Figure 1.

The process of attaching emissions to the facility location is similar to that followed by NRDC using an earlier version of the data to understand the regional health benefits of reducing emissions from these sources. Because we were interested in local health impacts, we conducted two additional steps in the preparation of this new iteration of the data.

Figure 1: Major GHG-Emitting Facilities in California



First, we used a variety of means to verify the address locations of the facilities indicated in the databases – a vital step since the purpose here is to consider local effects. While addresses were provided in the CARB Emissions Inventory for all facilities, these didn't always match the actual locations, sometimes because they were for the company headquarters instead of the actual refinery or plant. To determine correct locations, we cross-referenced the addresses given by CARB Emissions Inventory with data from the GHG Reporting Program, the CEC power plants database, and a dataset of facility locations from the U.S. Environmental Protection Agency (EPA), which provided geographic coordinates in addition to addresses, and then used aerial imagery[6] in Google Earth to visually confirm that the deduced coordinates were correct; in cases where they were not, we used the air photos to first find the facilities and then derive a set of coordinates that matched the emissions source at the facility. For a few facilities that seemed to be nowhere near their given coordinates or given address, we found their actual physical location through web-research, official documentation (e.g. permit history), and making phone calls to the parent companies.

Second, we verified NRDC's calculations of how the facilities impact the health of their neighbors, and updated it with more recent, 2006 data. NRDC researchers had created a "health impacts index" (for the formula, see the Technical Appendix) that quantifies, using health endpoint factors, how each facility's NO_x and $PM_{2.5}$ emissions increases premature mortality in the region, or more specifically, the local air basin.[7] The index is quite useful as a broader geographic measure of health impacts posed by a facility. At smaller scales, it must be used carefully. We use it in combination with population-weighted NO_x and PM_{10} emissions at varying distances from a facility for facility level analysis. For neighborhood level analysis, we use only proximity at various distances along with total co-pollutant emissions as indicators of health risk or burden.

We then gathered demographic and socioeconomic data on the neighborhoods surrounding facilities, using the 2000 Census data (Summary Files 1 and 3). We used block groups as the unit of analysis because it is the lowest level at which income information is available. Block groups consist of some number of similar blocks and in California have an average population of about 1,500. They are drawn to represent fairly homogenous populations in terms of demographic and economic characteristics, making them a good approximation of a neighborhood. They are more geographically detailed than census tracts, which are the next higher level of geographic aggregation in the census, and less detailed than census blocks, which are the lowest level of geography but one at which only basic demographic information is available.

Matching people in block groups with facilities is complicated. Facility addresses are a single point on a map but block groups are polygonal "aerial units" – that is, they have dimension. Thus, there are many instances in which a block group is only partially contained within a given distance of a facility (e.g., with a portion that is within one mile of a facility but with the remainder more than one mile away from that facility). A further complication is that block groups do not have evenly distributed populations – just think of a typical neighborhood wherein there might be several residential blocks adjacent to a mini-mall. Given that proximity is a central component to how co-pollutants affect people's health, how do we determine a definite measure of proximity?

We settled this dilemma in two ways. First, we considered where people were situated within each block group, attempting to gauge how many were within the specified distance of a facility, and second, we varied these distances to test the sensitivity of our measurements. On the first consideration, we created circular buffers around each facility and used them to capture census blocks – the components of block groups – to determine neighborhood proximity. Blocks that fell completely inside the buffer circle were counted as being proximate to the facility. Blocks that fell only partially inside the buffer circle were only considered proximate to the facility if the buffer circle captured the geographic center of the block (usually encompassing about half its area). We then tallied up the populations of the captured blocks to get the total share of the block group's population that was within the buffer circle, and used that number to appropriately "down-weight" any association between a facility and a block group that was only partially captured by a buffer circle. If, for example, six of a block groups' ten blocks were inside a facility's buffer circle and they accounted for 75 percent of the block group's population, then only 75 percent of the block group's population was associated with the facility and 75 percent of the facility's emissions were associated with the block group. This approach ensured a focus on where people actually live in relation to a facility and its emissions.

We also varied the perimeters to test for sensitivity. We specifically utilized half mile, one mile, two and a half mile, five mile, and six mile buffers to account for whether the inclusion of additional block groups moving away from the facility made a difference in terms of our analytical results. The broadest of these distances, six miles, is used by the California Energy Commission when it attempts to determine whether or not there are environmental justice communities located nearby any proposed location for a power plant. The other tighter distances have been utilized in much of the environmental justice literature to determine which neighborhoods might be considered proximate to, say, a facility listed in the Toxic Release Inventory maintained by the U.S. Environmental Protection Agency.

While we do not, in this report, delve into how tight the relationship is between distance and co-pollutant effect, one reason for drawing multiple buffers of different radii is because of the large variation in the size of the facilities subject to analysis. While they are represented as points on a map, some facilities may cover a large area and may have multiple points of emission, in which case a one mile buffer drawn from the center of the identified stack or plant address may, in reality, barely reach the perimeter of the lot containing the facility. By running all analyses under various distances and identifying consistent conclusions, we can discount the distorting effect that variation in facility size may have on our findings.

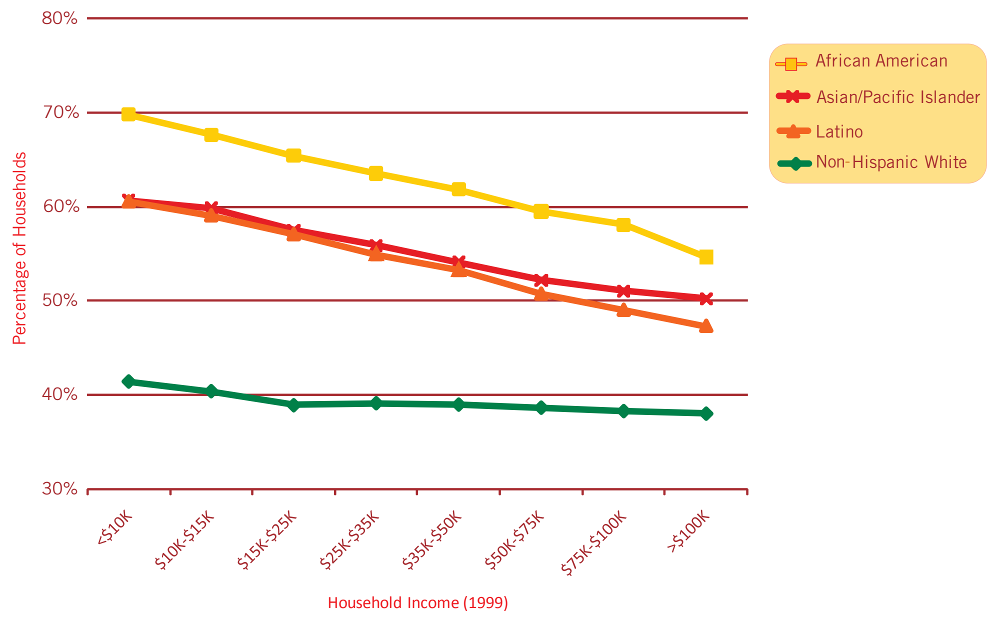
We use these geographic procedures to provide a picture of what each community looks like in terms of co-pollutant burden, and what each facility looks like in terms of the socioeconomic characteristics of its neighbors. Where a block falls within the reach of several faculties, its share of the block group is associated with each of those facilities to paint a cumulative picture. These aggregate portrayals enable us to examine neighborhood level patterns of environmental disparity and the facilities driving such patterns, the extent to which the co-pollutants of facilities burden nearby populations, and the effect of changes in emissions that might be anticipated under a cap-and-trade program.

The Neighborhoods

Unequal emissions burdens from this set of large GHG emitting facilities by race or ethnicity may seem like an obvious point given that existing environmental justice analyses of other sources of pollution in California and Southern California have already shown disparities for stationary as well as mobile sources of air toxics (see, for example Pastor, Sadd, and Morello-Frosch 2004). However, the large GHG emitters subject to this analysis are a different kind of air pollution source and one cannot presume that patterns will hold without empirical verification.

As it turns out, we find a familiar story: the neighborhood analysis reveals the facilities are unevenly distributed across space, with a disproportionate share in communities that include more people of color and more poor families.

Figure 2: Percentage Households Within 6 Miles of any Facility by Income and Race/Ethnicity, California



However, the data shows an interesting nuance not always shown in other studies. With regard to large GHG emitters, in California, there are distinct differences by ethnicity that seem to trump income differences.

Figure 2 shows the order of burden with the six mile distance range across income brackets and race. The likelihood of proximity is highest for African-Americans, then Asians, then Latinos, and finally non-Hispanic white. At the lower end of the income distribution, racial disparities are the largest, with African Americans having more than two-thirds of their lower-income households located near a facility. It is not much better for Latinos or Asians, particularly when compared to whites, whose share of households within six miles of a facility hovers around 40 percent across all income levels. Figure 2 makes clear that while it is true for all groups that the likelihood of living near a facility declines as income rises (as does the racial disparity between groups), there remain difference by race at each and every level of income. And while the focus here is on the six mile distance, this pattern is the same at other distances.

While Figure 2 looks at the likelihood of a particular group living within six miles of a facility, Table 1 offers a more nuanced view: the composition of the neighborhoods within each of the buffers. The first five columns of the table present statistics for sets of block groups near any large GHG emitting facility by various distances; the same set of statistics is calculated for all block groups further than six miles away from a facility for purposes of comparison (column six). As discussed above, considering the results at a variety of distances helps ensure that conclusions are based on actual trends instead of statistical flukes.

The table shows that nearly half of all Californians live within six miles of a facility (46 percent), but they

Table 1: Average Characteristics by Distance from a Facility

	< Half Mile	< 1 Mile	< 2.5 Miles	< 5 Miles	< 6 Miles	> 6 Miles
Total Population	96,362	575,014	4,368,581	12,844,279	15,492,631	18,226,753
% of California Population	0.3%	1.7%	13.3%	38.8%	45.9%	54.1%
People Per Square Mile	1,002	1,325	1,841	1,802	1,779	125
Non-Hispanic White	42.6%	41.2%	37.4%	37.5%	38.0%	54.0%
People of Color	57.4%	58.8%	62.6%	62.5%	62.0%	46.0%
African American	8.7%	8.2%	8.3%	8.5%	8.6%	4.6%
Latino	35.0%	38.1%	40.2%	38.6%	37.5%	28.1%
Asian/Pacific Islander	10.2%	8.9%	10.6%	12.0%	12.6%	9.7%
1980's and 1990's Immigrants	19.1%	20.3%	20.9%	21.3%	21.4%	15.4%
People Below Poverty Level	16.5%	16.3%	16.8%	16.9%	16.6%	12.2%
Children (under 18 years)	24.0%	26.8%	28.5%	28.1%	27.7%	27.0%
Renters	56.0%	52.8%	50.3%	49.6%	49.4%	37.8%
Per Capita Income (1999)	$21,399	$20,794	$20,043	$20,950	$21,186	$24,013
Relative Median Household Income (CA median = 100)	87.7	87.7	90.4	93.5	94.0	105.0

are disproportionately people of color – 62 percent of nearby residents are people of color as compared to the 38 percent who are non-Hispanic white. African Americans live disproportionately close to facilities; their share of the population within half a mile of a facility is about twice their share of the population living outside of the six-mile range. The Latino community share is highest at the two and a half mile range, where they make up about 40 percent of that proximate population as compared to only 28 percent of those more than six miles away. Asian Pacific Islanders are also overrepresented within six miles of a facility, with the disproportionality most marked in the farthest reaches.

Beyond race and ethnicity, there are troubling trends for other vulnerable populations: immigrants, youth and the poor. Immigrants from the 1980's and 1990's are overrepresented within the six mile range, with a pattern similar to that seen in the "people of color" category. Children in poverty (not shown), along with all people in poverty, are both disproportionately near facilities – around 23 percent and 17 percent within six miles versus 16.3 percent and 12.2 percent more than six miles away, respectively, with only slight variation within the six mile radius. Though not shown in the table, we also examined figures utilizing 150 percent of the poverty line (since some argue this is a better measure of low income for a high-cost state like California) and found the same pattern. As for other income measures, there are more renters, lower per capita incomes, and lower household incomes near polluting facilities.

In looking at the pattern, the two and a half mile radius is, we think, of special interest, partly because it captures a much more reasonable share of the overall California population (just over 13 percent) and represents a balance between stretching too far (six miles) and too tight (the half mile radius in which we capture very few people and are not allowing for the ways in which co-pollutants can travel well beyond plant boundaries). It is also the distance at which the highest correlation was found between the population-weighted co-pollutant emissions (person-tons of co-pollutants) we later consider and the air basin-wide health impacts index utilized by NRDC. The snapshot reveals that this is also a distance at which many of the disparities are the most pronounced.

While the demographic indicators in Table 1 are useful, they do not account for the relative burdens the neighborhoods carry. Columns one through

Table 2: Average Characteristics by PM_{10} Emissions from Facilities Within 6 Miles

	High Emissions	Middle Range	Low Emissions	No Facilities Within 6 Miles
Total Population	2,317,884	10,940,640	2,234,107	18,226,753
% of California Population	6.9%	32.4%	6.6%	54.1%
People Per Square Mile	2,638	1,746	1,425	125
Non-Hispanic White	34.4%	37.7%	43.5%	54.0%
People of Color	65.6%	62.3%	56.5%	46.0%
African American	15.9%	7.8%	4.9%	4.6%
Latino	34.5%	38.8%	33.9%	28.1%
Asian/Pacific Islander	11.7%	12.5%	14.3%	9.7%
1980's and 1990's Immigrants	18.7%	22.2%	20.2%	15.4%
People Below Poverty Level	17.5%	16.3%	16.8%	12.2%
Children (under 18 years)	31.1%	30.5%	30.5%	29.4%
Renters	50.6%	49.6%	47.3%	37.8%
Per Capita Income (1999)	$20,986	$21,482	$19,945	$24,013
Relative Median Household Income (CA median = 100)	90.8	95.8	88.4	105.0

five, for example, only break up neighborhoods according to whether they have *any* facility inside the specified distance, but some neighborhoods are within range of several facilities, and not all facilities emit the same amount of pollution. Because in-depth emissions modeling is beyond the scope of this project – although the results we offer up suggest it might be useful for a next phase – we instead employ a fairly simple methodology in which we sum up the tons of co-pollutant emissions for each co-pollutant by neighborhood (block group) from all facilities within six miles, and classify these neighborhoods into three categories: High Emissions (greater than average), Middle Range (about average) and Low Emissions (less than average), with the breaks derived through looking at the mean and what is called a standard deviation (see the appendix for details). The results of this approach are shown in Table 2. The comparison group, here, is the same used in Table 1, those neighborhoods in the greater than six mile range. We focus here on PM_{10} because is it a well known co-pollutant with serious health effects including respiratory problems, cardiovascular disease and premature death.[8]

Gauging relative emissions burdens by breaking up the neighborhoods by total emissions from *all* facilities rather than by proximity to *any* facility, we find some differences, particularly in racial composition, that did not show up in the first part of Table 1, while others that did show up are strengthened and still others change in different ways. African Americans are drastically overrepresented in the High Emission group of neighborhoods, making up about 16 percent of the population – more than three times their share in either the Low Emissions group of neighborhoods or neighborhoods outside the six mile range of any facility. Latinos have their highest population representation in the middle range of emissions, and while Asians are over represented at each emissions level, their share is the highest in the places with lower emissions. As a group, there is a disparate pattern for all people of color: they make up about 46 percent of the population outside the six mile range, 57 percent of those in Low Emission areas, and 66 percent of those in High Emission areas. Again, while we only show the results at the six mile range, they are similar at other distances, including the two and a half mile distance which becomes the focus below.

While all the areas with emissions have lower income levels than in the rest of the state, and poverty generally rises with the level of emissions, one result may seem surprising: both the High Emissions *and* the Low Emissions neighborhoods have slightly lower levels of per capita and household income than the Middle Range neighborhoods. The reason seems to be that the Low Emissions areas – which have facilities but less clustering of facilities and/or facilities with lower emissions – tend to be more rural, which is geographically associated with lower-income.

In any case, the data suggests that, on average, communities of color tend to be situated near the facilities with the highest emissions, or clusters of facilities whose combined emissions add up, while pre-dominantly Anglo or mixed communities tend to live either around facilities with less emissions or beyond the range altogether. Place matters, and existing residential patterns leave communities of color more exposed to facilities that are responsible for the greatest share of co-pollutant emissions. The question, now, is how to ensure that emissions are reduced where the burdens are the largest (i.e. those neighborhoods in the High Emissions category), and in so doing, ensure that "co-benefits" go to communities on the least advantaged side of the climate gap. To begin answering this question, we try to determine which industries are driving the emission trends.

The Industries

To understand what cap-and-trade could mean for environmental justice, we assessed which sectors and which facilities pose the greatest threat to their neighbors' health and where emissions reductions would accordingly provide the greatest benefit. This analysis reveals the distribution of responsibility by sector and facility. Such an analysis may inform the debate by helping to quantify the worst case and best case scenarios for environmental justice with regard to these facilities. For example, if the responsibility for the inequity is spread evenly across sectors and facilities, then exactly which ones curb their GHG emissions is less important for promoting environmental justice; therefore, cap-and-trade is unlikely to be a cause for public health concern because reductions anywhere would ameliorate the overall disparate pattern. If, on the other hand, the inequity is largely due to a small set of facilities, or largely restricted to a particular sector, then those facilities or that sector's purchase of allowances or failure to make reductions could significantly exacerbate existing inequalities. Trades among these facilities would be of highest concern.

Of course, the real gold standard in this task would involve forecasting how and where trades would occur (or, in the case of fees, predicting which firms would choose to pay rather than reduce emissions). However, this kind of predicting would require good financial and economic data on firms that is difficult to acquire and complicated to model. Further, it would mean making assumptions about the details of AB 32 implementation that have yet to be determined, such as how many allowances would be auctioned and at what price to which sectors. While this analysis can have value, it is beyond the scope of this report. Instead we focus on the disparities that facilities are already causing and what policy makers and regulators should take into account when creating safeguards against health-impacting trades that could widen the climate gap.

To measure the contribution of each facility to environmental disparities, we account for three measures. First, we determine how many Californians are impacted by any particular facility, utilizing information on the density of surrounding neighborhoods. Second, we take into account the total tons of co-pollutant emissions from the facility as a gauge of relative health burden. Third, we measure the racial/ethnic composition of the impacted population. These three factors in combination help us gauge the magnitude of disparity by sector, and later by facility; we focus here on PM_{10} emissions due to the regulatory emphasis on the established adverse health effects of particulates (and since the results for NO_x are similar to those of PM, they are omitted from reporting for the sake of brevity).

Figure 3: Average Population per Facility (in Thousands) By Distance from Facility in California

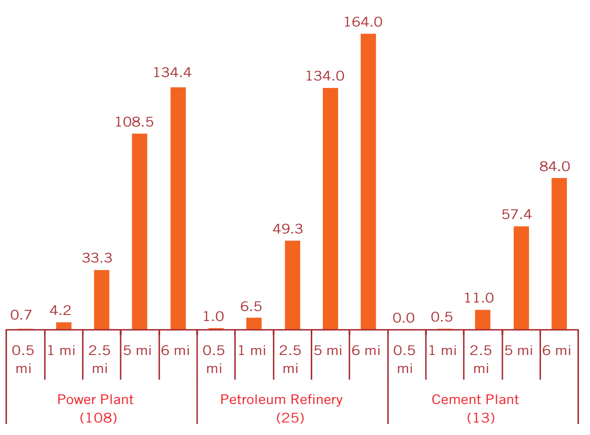
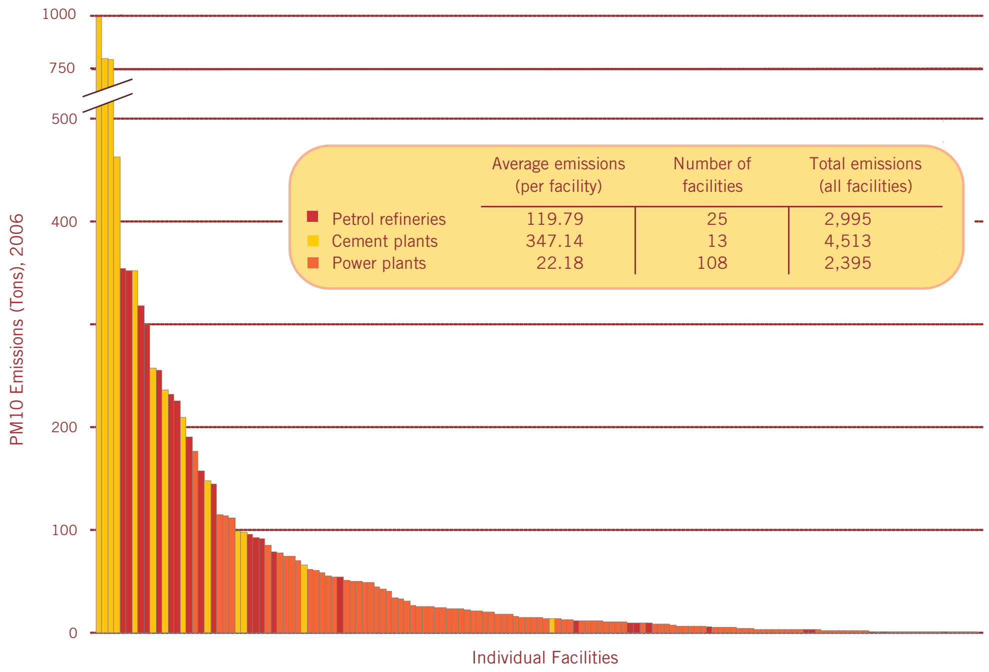


Figure 3 starts the analysis by counting up the populations within ranges of facilities and giving the total for sectors. Note that while power plants will affect more people overall due to their sheer number, refineries generally have the highest proximate population within the different ranges for the average facility. Power plants in California may also be the least harmful in terms of health impacts and least inequitably distributed by race. Despite the fact that there are more people living within a six mile radius of power plants than other facilities – primarily because there are so many more power plants than refineries or cement kilns – the 108 plants release the lowest tonnage of co-pollutants (see Figure 4

Figure 4: PM_{10} Emissions (Tons) by Facility

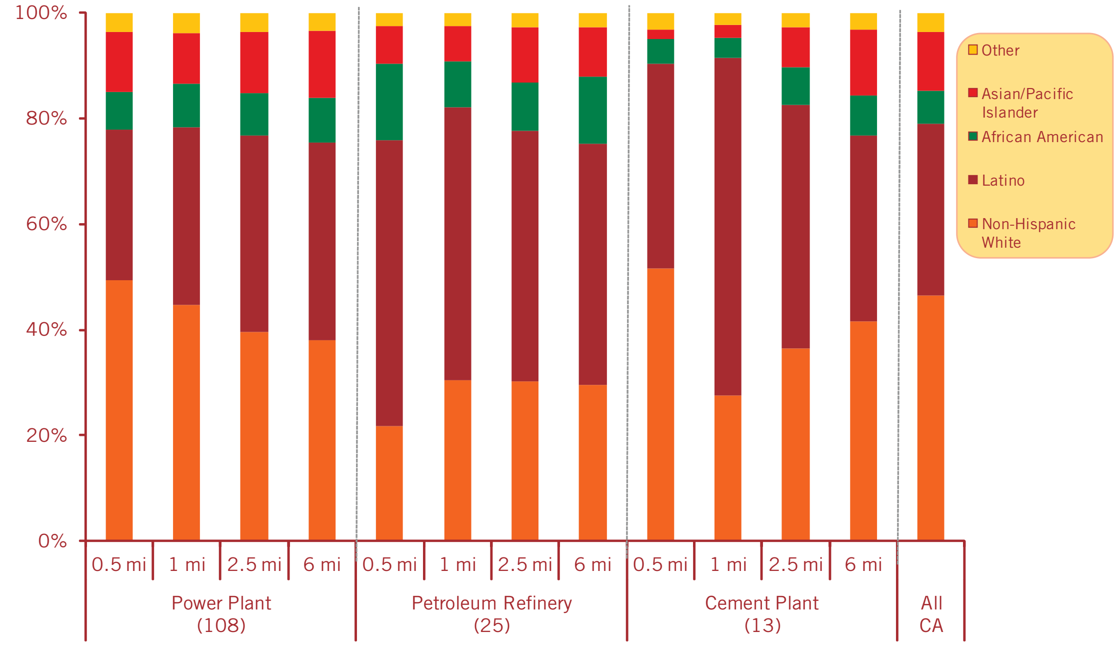


	Average emissions (per facility)	Number of facilities	Total emissions (all facilities)
🟥 Petrol refineries	119.79	25	2,995
🟨 Cement plants	347.14	13	4,513
🟧 Power plants	22.18	108	2,395

in which we order the various types of facilities by their PM emissions from most to least – the power plants show up most frequently in the long tail of the distribution where emissions are lowest while cement plants and refineries show up more frequently in the early part of the distribution where emissions are much higher, resulting in combined emission by sector being highest for cement plants, followed by refineries, and lowest for power plants). Power plants also affect the lowest share of non-white residents, particularly at the nearer distances (Figure 5).[9] This is not to deny rather spectacular cases, including the recent attempt to expand a power plant in Vernon that gave rise to significant resistance from adjoining communities. Such resistance made sense: the current Vernon plant is the top power plant contributor to environmental inequity by race in California, due partly to its proximity to a predominantly immigrant population living in an area of high population density.

Petroleum refineries offer a more problematic picture. They are, on average, located in more densely populated areas (Figure 3) that are consistently home to communities of color (Figure 5). The total minority share ranges between 70 and 78 percent (depending on the particular distance) within six miles of the facility – on average, easily the most disproportionate of the three sectors. Particularly notable, blacks make up a large share in the closest distance buffers, more so than for cement plants and power plants. At the half mile distance, the African American share is more than double their share of the state population (14 percent as compared to 6 percent) and at the one mile distance it is one and a half times as high. Refineries are also unique in that their associated demographics are quite consistent

Figure 5: Racial/Ethnic Composition of Population by Distance from Facility California



throughout the surrounding geography, at least beyond the immediate half mile range. They tend to have much higher co-pollutant emissions than power plants, but lower than cement plants (Figure 4).

Although cement plants are few and affect few (Figure 3), they are by far the dirtiest (again, see the distribution as well as the average emissions figures in Figure 4). At the closest range of half a mile, non-Hispanic Whites are actually slightly overrepresented as compared to the state. However, the number of people in this range of cement plants is very small (about 300 people in all). When we consider the much larger population within one mile (about 6,500 people) the minority population is large, due almost exclusively to the high concentration of Latinos who make up 64 percent of the population (Figure 5). The percentage minority declines rapidly moving further away from cement facilities due exclusively to a steep decline in the Latino share of the population, supplemented by a steep increase in the non-Hispanic White share, and despite both a steep increase in the Asian/Pacific Islander share and a more modest increase in the African American share.

The Disparities

Closing the climate gap requires measuring the factors that contribute to any disparity in environmental burdens. To evaluate the contribution of each facility to the overall pattern of environmental disparity, we developed a single metric of disparity that combines the total impacted population, PM emissions, and the racial/ethnic composition of the surrounding neighborhoods. Such a measure can characterize the individual impact of one facility, but it also allows us to aggregate by sector or across all facilities in the state. It captures the difference in relative impact between a facility located in a sparsely populated area with a population that is 90 percent minority but whose emissions are moderate, and a facility in a densely populated area that is 70 percent minority, but with very high emissions.

The index we developed – the “pollution disparity index” – measures the relative co-pollutant burden on communities of color, as compared with non-Hispanic white communities. We start our calculations at the facility level. Using the socioeconomic neighborhood characteristics that have been attached to each facility, we approximate the local PM_{10} emissions burden as the population-weighted PM_{10} emissions (i.e. total person-tons of PM_{10}) for people of color and non-Hispanic whites. Using such a population-weighted emissions measure means that a facility may have a higher score for people of color even if it has a lower share of people of color in the vicinity because, although the community of color is a lower percentage, it is larger in population and around a facility with higher emissions. We then subtract the population-weighted PM_{10} emissions for non-Hispanic whites from those for people of color (after adjusting the weights by dividing by the number of each group in the state), which gives us the pollution disparity index for that facility, or a measurement of environmental injustice (See the Technical Appendix for details). If the pollution disparity index is added up across all facilities in the state, the result is equal to the statewide difference – or disparity – in average PM_{10} emissions burden between people of color and non-Hispanic whites.

Every facility in our data set is given a pollution disparity index at the varying buffer distances used throughout this analysis (half mile, one mile, two and a half mile, five mile, and six mile), with the characteristics of the “neighborhood” determined by the distance from the facility. The pollution disparity index can then be used to aggregate (at discrete distances bands) for different levels of analysis – it can be combined by sector or across the facilities in a particular region to get the combined contribution of that group of facilities to the statewide disparity in average PM_{10} emissions burden between people of color and non-Hispanic whites caused by all facilities under analysis.

While we cover many technical details of this calculation in the Technical Appendix, a few are worth noting here. First, the measure of population-weighted PM$_{10}$ emissions upon which the pollution disparity index is based should be viewed only as a relative measure that compares the impact of facilities and their disparity within each buffer distance and not across them (similar to the Risk Screening Environmental Indicators risk score developed by the U.S. EPA; see Ash, et al. 2009). Second, the pollution disparity index can have positive and negative values. This depends on the demographics of the neighborhood near the facility; if the share of the state's people of color residing near the facility is greater than the share of the state's non-Hispanic white population residing near the facility, then the score will be positive (if reverse is true, it will be negative). Third, we are effectively assuming in this calculation that beyond six miles, there are no emissions. In practice this is not true, but as mentioned earlier, doing complex emissions dispersion modeling is beyond the scope of this report. Finally, the pollution disparity index is just that – an index of demographic disparity in local pollution burden and not a pure measure of local pollution burden. Thus, while it is useful for highlighting the most disparate facilities, it should be considered in practice along with overall local pollution burden (e.g. population-weighted PM$_{10}$ for all people) as we do below.

The formula for the pollution disparity index also allows for determining average emissions burdens for individual ethnic groups. To do this, we calculate the population-weighted PM$_{10}$ emissions for each ethnic group around each facility, divide it by the state population for each group, and then sum it up to the California level, at each buffer distance. The resulting average burdens are summarized in Table 3; there, the emissions burdens rise with distance because we are "allowing" a wider range of facilities to have an impact on any particular community.

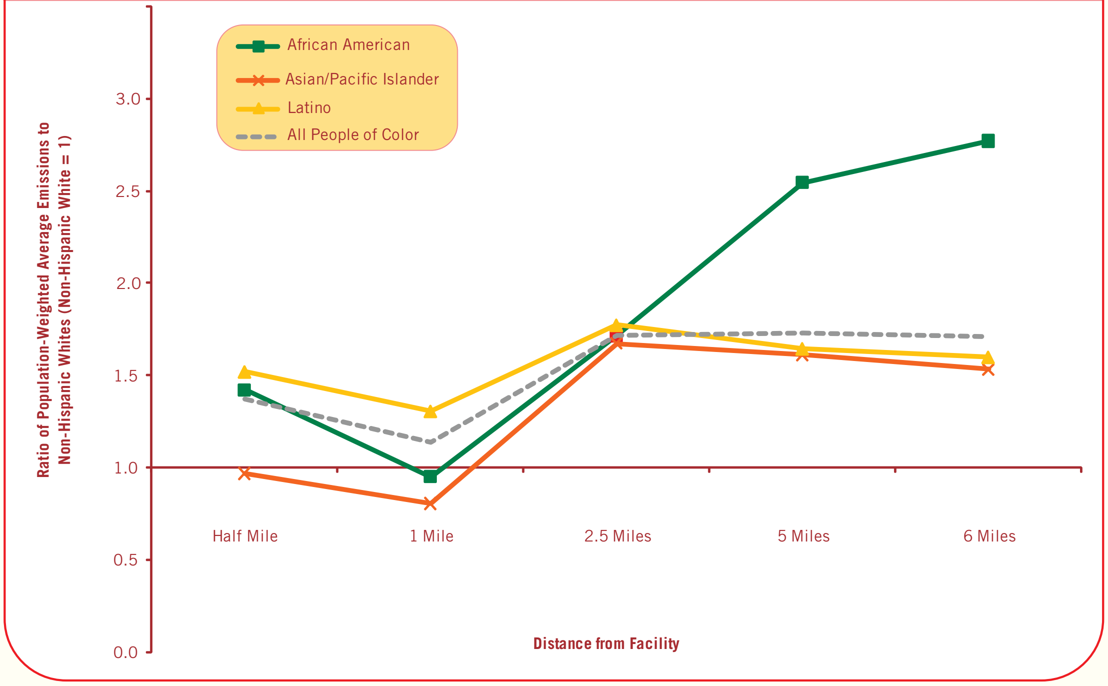
The difference between the average value for each group and that for non-Hispanic whites at each distance in Table 3 is a measure of statewide disparity in PM$_{10}$ emissions burden between that group and non-Hispanic whites at that particular distance. To determine relative differences in emissions burden, which allows us to compare the degree of disparity across the distances, we simply divide the average value for each racial/ethnic group by that for non-Hispanic whites at each distance. The resulting relative PM$_{10}$ emissions burdens are reported in Figure 6.

With the exceptions of Asians at the half and one mile distances, and African Americans at the one mile distance, there are persistent gaps at each level; the relative emissions burden for all people of color combined is always above that for non-Hispanic whites (which is always equal to one in the graph). The trend for Latinos is similar to the trend for all people of color, which is not surprising given that Latinos constitute the overwhelming majority of non-

Table 3: Population-Weighted Average Annual PM$_{10}$ Emissions (Tons) Burden by Race/Ethnicity

	Half Mile	1 Mile	2.5 Miles	5 Miles	6 Miles
Non-Hispanic White	0.07	0.67	6.73	29.55	41.51
African American	0.10	0.64	11.55	75.23	115.03
Latino	0.11	0.88	11.93	48.61	66.37
Asian/Pacific Islander	0.07	0.54	11.26	47.62	63.57
All People of Color	0.10	0.77	11.54	51.08	70.98

Figure 6: Relative Racial/Ethnic Inequities Compared to Non-Hispanic Whites in PM_{10} Emissions Burden from Large GHG-Emitting Facilities by Buffer Distance



whites. They have the greatest emissions burden of any group up to the two and a half mile range where it levels off and declines slightly, while the emissions burden for African Americans soars dramatically to nearly three times the level for non-Hispanic whites at the six mile range. As for Asians, once we move beyond the one mile range, there are also persistent differences. Following the pattern for Latinos, as distance increases beyond the two and a half mile range, the disparity for all people of color combined levels off.

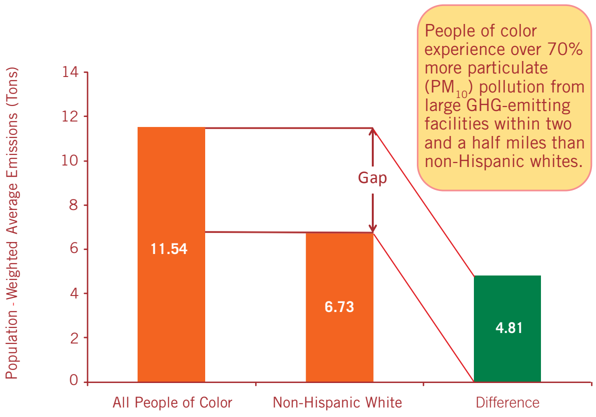
The Sectors

Given the disparity in PM emissions burdens for people of color seen in Figure 6, we decided to examine whether power plants, refineries, or cement plants were driving the overall trend. For this analysis, we focus on the two and a half mile distance threshold. We think this is a reasonable distance for portraying our results in terms of emissions burden – and it is also the case that the population-weighted emissions burden at two and a half miles is the most highly correlated among the different buffer distances with the air basin-wide Health impacts index, giving us some confidence in this choice of radius. In any case, the relative contribution of the various sectors and facilities to statewide inequity as measured by the pollution disparity index is not particularly sensitive to the buffers (with the exception of the half mile distance due to the very small populations captured in that range), so focusing in on one distance illustrates the overall pattern and allows for brevity in the presentation.

Figure 7 begins this analysis by graphically displaying the difference in emissions burdens between people of color and non-Hispanic whites seen in the third column of Table 3. Figure 8 then calculates which sectors are accounting for the PM emissions loads of each group and for the difference between them. From this, we can see that while refineries account for the majority of PM_{10} emissions burden for all people, they account for a much larger share (about 93 percent) of the difference in emissions burden between people of color and non-Hispanic whites.

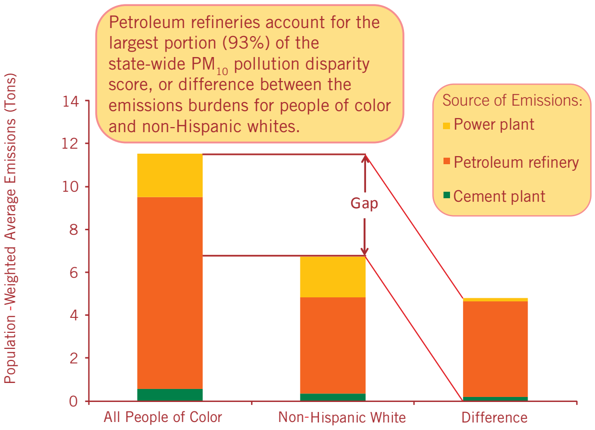
Which facilities are driving this difference in emissions burden? Because the statewide difference is simply the sum of the pollution disparity index across all facilities, we are able to rank the facilities by the index in Figure 9. The ranking confirms that refineries are driving the difference, as they are eight of the top ten contributors to co-pollutant emissions disparity. Moreover, the top eight facilities overall actually add up to the entire difference; if you took all the facilities below that, you'd have an even distribution of PM_{10} emissions burden by race, since some facilities (displayed at the bottom of the distribution in that figure) disproportionately burden whites. The full distribution also shows that a vast majority of facilities have a score near zero. In short, a few facilities, mostly petroleum refineries, account for most of the observed inequity.

Figure 7: Population-Weighted Average Annual Particulate (PM_{10}) Emissions Burden (Tons) by Race/Ethnicity for Facilities within 2.5 Miles



People of color experience over 70% more particulate (PM_{10}) pollution from large GHG-emitting facilities within two and a half miles than non-Hispanic whites.

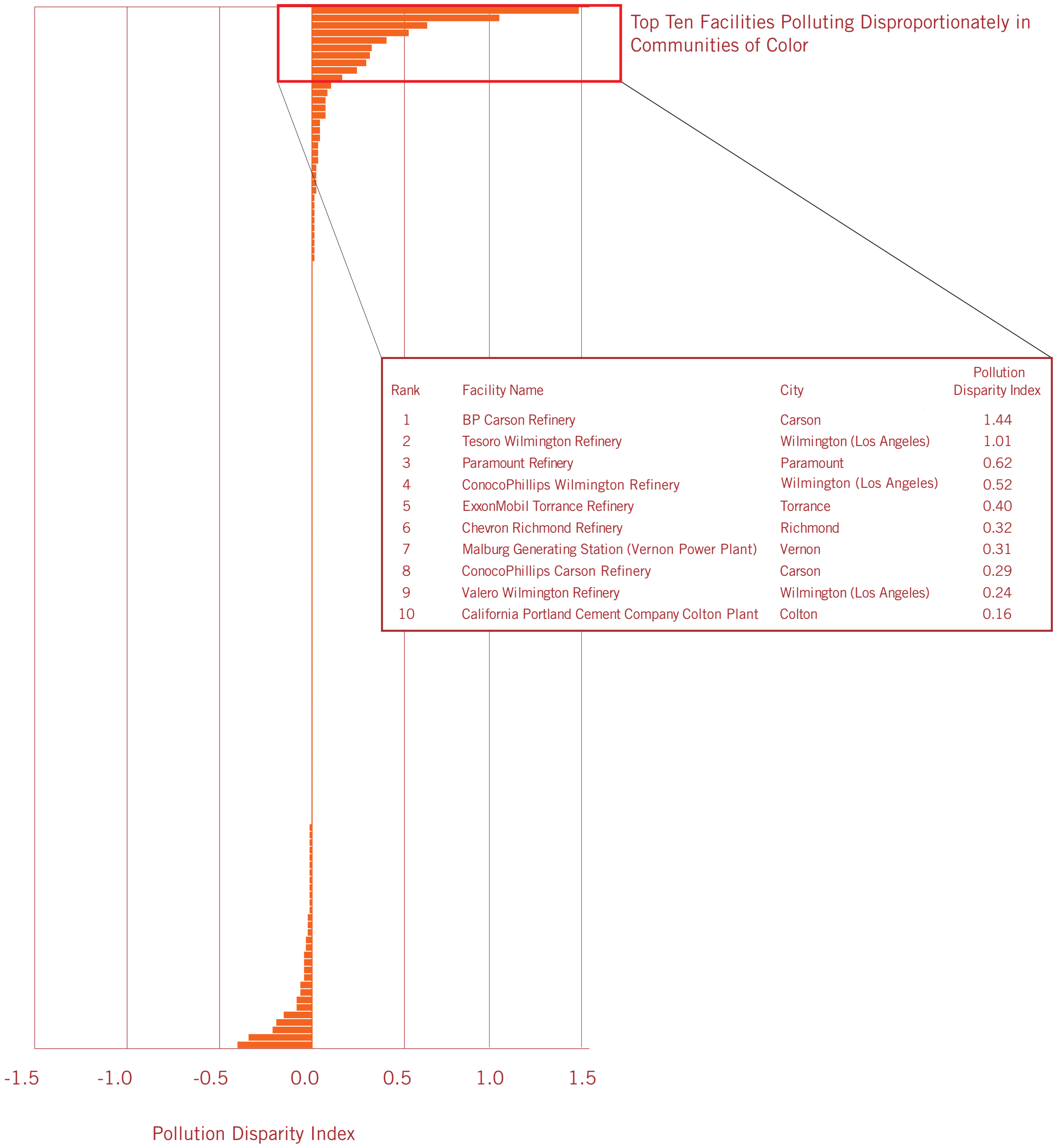
Figure 8: Population-Weighted Average Annual Particulate (PM_{10}) Emissions Burden (Tons) by Facility Category and Race/Ethnicity for Facilities within 2.5 Miles



Petroleum refineries account for the largest portion (93%) of the state-wide PM_{10} pollution disparity score, or difference between the emissions burdens for people of color and non-Hispanic whites.

The geographic location of the top ten facilities is depicted in Figure 10. There we can see that nearly all are in Southern California, with only one in the San Francisco Bay Area – the Chevron refinery in Richmond, which ranks sixth in pollution disparity. In Southern California, we see that it is mainly a cluster of refineries around the Los Angeles and Long Beach ports that are driving the pattern of disparity, with five of the remaining top ten facilities located in or adjacent to the port-side neighborhood of Wilmington (part of Los Angeles City). These include the BP refinery in Carson, which takes first place in disparity, and the Tesoro Wilmington Refinery, which comes in second. The rest of the top ten facilities include two refineries (the Paramount Refinery in Paramount and the ExxonMobil Torrance Refinery in Torrance), one power plant (the Malburg Generating Station in Vernon), and one cement plant (the California Portland Cement Company Colton Plant in Colton).

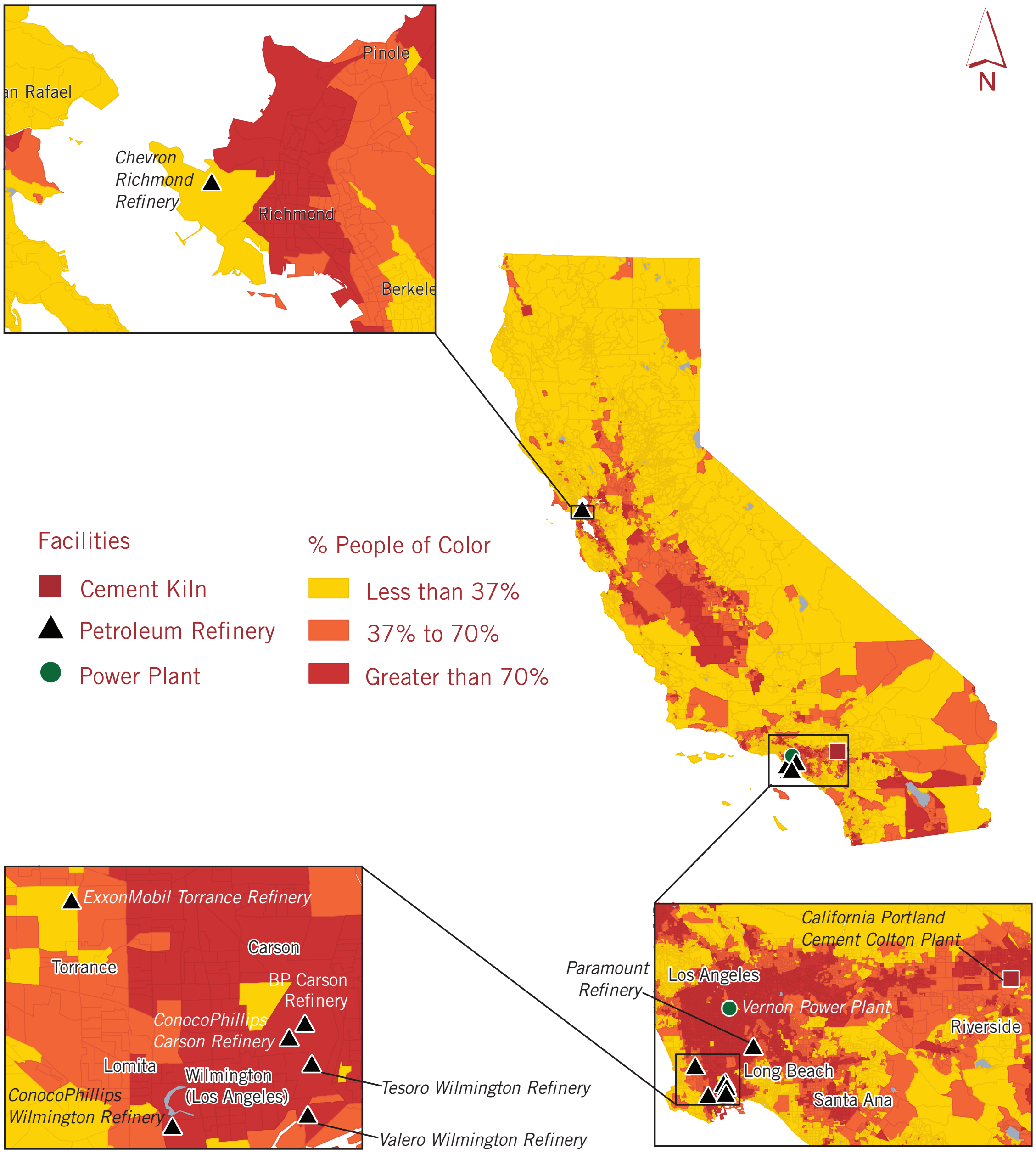
Figure 9: Distribution of the Pollution Disparity Index for PM_{10} at 2.5 Miles Across All Major GHG-Emitting Facilities



Top Ten Facilities Polluting Disproportionately in Communities of Color

Rank	Facility Name	City	Pollution Disparity Index
1	BP Carson Refinery	Carson	1.44
2	Tesoro Wilmington Refinery	Wilmington (Los Angeles)	1.01
3	Paramount Refinery	Paramount	0.62
4	ConocoPhillips Wilmington Refinery	Wilmington (Los Angeles)	0.52
5	ExxonMobil Torrance Refinery	Torrance	0.40
6	Chevron Richmond Refinery	Richmond	0.32
7	Malburg Generating Station (Vernon Power Plant)	Vernon	0.31
8	ConocoPhillips Carson Refinery	Carson	0.29
9	Valero Wilmington Refinery	Wilmington (Los Angeles)	0.24
10	California Portland Cement Company Colton Plant	Colton	0.16

Figure 10: Map of Top Ten Facilities in Pollution Disparity



The Risks

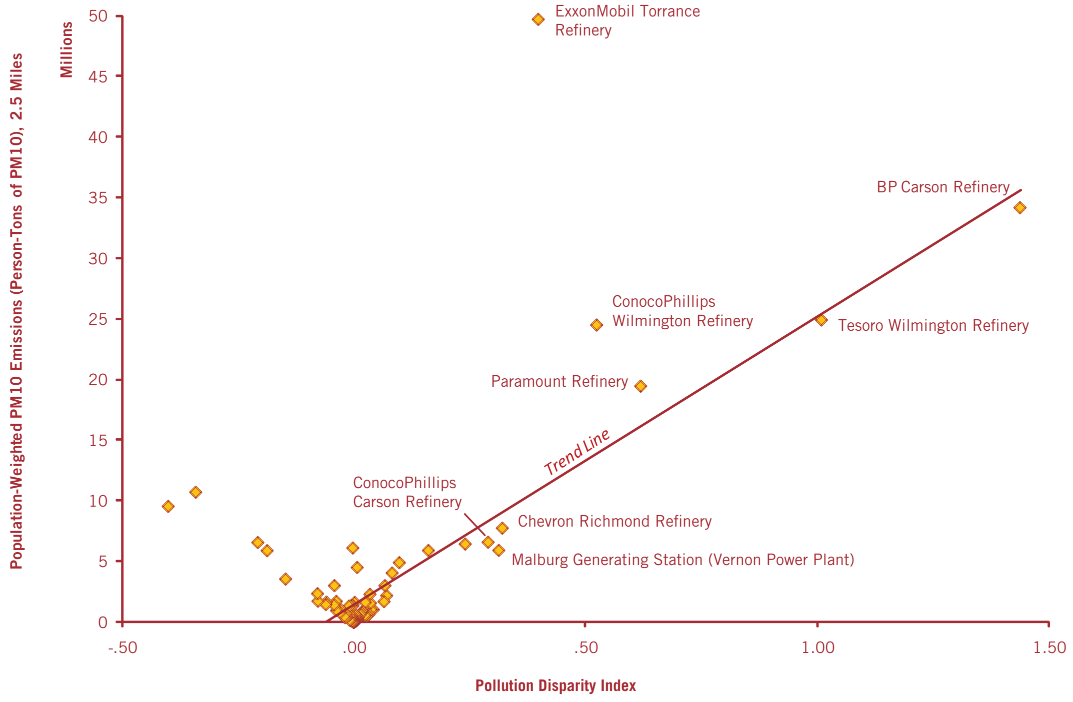
What does all this mean for lowering carbon emissions, protecting public health and closing the climate gap? How should these findings affect CARB's implementation of AB 32? What are the broader implications for market-oriented policies that might eventually emerge at the national level?

The first point made by this analysis is that some trades or allowance allocations *could* widen the climate gap by worsening disparities in emissions burdens by race/ethnicity. The second point is that while there are legitimate concerns about outcomes resulting from trades or the distribution of allowances *within* a sector – such as when a power plant that impacts a large number of people in low-income communities of color eschews reductions in favor of buying credits from a power plant that is nowhere near any population of size or outbidding that power plant in an allowance auction – the real concern might be trade and allowance distribution *between* sectors.

The third point that emerges from this work is the fact that it is a relatively small number of facilities that are driving most of the disparity in emissions; while this could be a problem, the concentration of "bad actors" also suggests that regulatory efforts could be carried out in an administratively feasible and cost efficient way to maximize public health benefits of GHG reduction strategies in the communities that need them the most.

Another point, which is of great importance for policy, is that targeting these facilities would help everyone. Recall, for example, that we employed the two and a half mile distance buffer in our analysis partly because of the strong correlation between population-weighted co-pollutant emissions at that distance and the health impacts index for the air basin derived using the measure indicated in Bailey et al. (2008). In Figure 11, we plot that measure

Figure 11: PM_{10} Emissions Burden and Racial/Ethnic Inequity by Facility



against the pollution disparity index. There we can see that the two measures generally have a positive relationship – the higher the emissions burden the higher the inequity – and it is a handful of facilities with extreme values that are really driving the positive correlation (as they did in our analysis of disparity by race). The pattern suggests both that these are the sites of concern *and* that focusing on disproportionality will also have strong impacts on overall health (or vice versa). For example, in absence of the top eight facilities in terms of the pollution disparity index (labeled in Figure 11), co-pollutant emissions would be more or less evenly distributed by race/ethnicity *and* overall emissions burden would be significantly reduced.

Table 4 illustrates this in a slightly different way by showing the top ten percent of the facilities studied ranked by the aforementioned health impacts index (which is more regional in scope). There we see many of the same facilities that were identified as the most disparate by race/ethnicity in Figure 9, with eight of the ten most disparate facilities also ranking highly in terms of potential health impacts.

Clearly, facilities have to be located somewhere and not all sites will find it cost-efficient to be the first to reduce their emissions. These facilities will be among those purchasing relatively more credits and the last to realize co-pollutant reductions in their neighborhoods. While we have not demonstrated conclusively that the disparity by race *will* sharpen, we have shown that this type of disparity *could* sharpen.

The text of AB 32 unmistakably lifts up health benefits from reduced co-pollutants as an important objective of the legislation, and the California Air Resources Board has long indicated a serious concern about promoting equitable environmental outcomes as part of its overall program of activities. With the issues of overall burden and disproportionate burden intimately related, CARB could craft safeguards that ensure market strategies address these concerns and help close the climate gap.

The Policy Choices

So what would an environmentally just GHG reduction strategy look like? We suggest a menu of market-based and regulatory approaches that could work toward a more equitable outcome.

Table 4: Top Ten Percent of California's Major Greenhouse Gas-Emitting Facilities Ranked by the Health Impacts Index

Rank	Facility Name	City	Health Impacts Index
1	ExxonMobil Torrance Refinery	Torrance	54.4
2	Tesoro Wilmington Refinery	Wilmington (Los Angeles)	50.0
3	BP Carson Refinery	Carson	46.3
4	Chevron El Segundo Refinery	El Segundo	41.2
5	ConocoPhillips Wilmington Refinery	Wilmington (Los Angeles)	30.3
6	Shell Martinez Refinery	Martinez	27.1
7	Valero Benicia Refinery	Benicia	19.1
8	Mountainview Power Plant	San Bernardino	17.5
9	Chevron Richmond Refinery	Richmond	17.3
10	California Portland Cement Company Colton Plant	Colton	14.1
11	Paramount Refinery	Paramount	13.8
12	Valero Wilmington Refinery	Wilmington (Los Angeles)	13.0
13	Cemex Victorville/White Mountain Quarry	Apple Valley	12.5
14	Tesoro Golden Eagle Refinery	Martinez	12.1
15	Etiwanda Generating Station	Rancho Cucamonga	11.1

First, one theoretically ideal but perhaps logistically challenging approach would entail pricing in the co-pollutants along with carbon. In this case, allowances might get extra credit (or carbon fees might be priced differently) depending on the ratio of co-pollutants to GHG. Suppose, for example, that a carbon fee was higher (or allowances were more expensive) if co-pollutants were more prevalent and/or population densities were greater; this could induce deeper GHG reductions in locations where health benefits would be maximized.

This is an elegant idea but one that would involve significant complexity in allowance design, could create problems in a trading system (which is easier if allowances are homogenous units measured only by their carbon emissions), and could significantly complicate the administration and compliance for either a trading or fee system. A simpler approach might be to vary permit prices (or fees) by the average relationship between co-pollutants and GHGs in different sectors, but this would be highly inefficient because it does not consider the substantial variation in marginal health co-benefits from GHG reduction that appears to exist at the facility level.

We see four other strategies that might make sense and be easier to implement.

The first strategy involves identification of those facilities that either have very high co-pollutant levels or make a very significant contribution to the pattern of environmental disparity in the state. These facilities – which should be small in number – would be restricted in allowance allocations, purchases of allowances from other facilities, and use of offsets, required instead to reduce emissions locally to meet their contribution to achieving the statewide carbon cap. While this might limit the market, it would be a small imposition on the system as a whole and would target only a handful of facilities. In a fee system, these facilities could be restricted in their capacity to pay fees rather than change operations.

A second strategy involves the creation of trading zones, based not on whether the facility imposes a significant burden but whether the adjacent areas are currently overburdened by emissions. Zonal restrictions on trading were used in the second phase of the RECLAIM program in Southern California, in which inland facilities were allowed to purchase credits from coastal facilities (where pollution was highest) as well as other inland facilities but coastal facilities were prohibited from making out-of-zone buys (Fowlie, Holland and Mansur 2009). This imposes some inefficiency but it is not administratively complex and it could be justified by the associated environmental benefits. However, as Kaswan (2009) suggests, certainty in achieving actual reductions in prioritized areas would largely depend on how allowances were distributed, with trading playing a small role, for example, if facilities are able to purchase all the allowances they need for any compliance period at auction or if they are able to rely on offsets to make up the difference between allowances holding and emissions. Thus, for this strategy to be effective it would have to be coupled with limits on overall allowance allocations and use of offsets in such zones to ensure that the total quantity of emissions allowed in the zonal market amounted to a net reduction of sufficient size. The zonal restrictions on trading would then prevent any increase above that level and likely lead to further reductions.

A third strategy involves the imposition of surcharges on allowances or fees in highly impacted areas, with the funds being returned for environmental and other improvements in those same areas. In this case, some facilities that are not the worst offenders – but share responsibility for the highest impacts because of their location – would be forced to contribute as well. This would create a tight nexus between the surcharge and the improvement and would be justified by the potential health benefits that could be realized (Boyce 2009).

A fourth strategy involves the creation of a community benefits fund, based as a share of all the monies collected from allowance auctions or fees that could target emissions improvements in neighborhoods that are overburdened, regardless of whether they are in the same location as the sources. Such neighborhoods could be identified through examining dimensions such as the proximity to hazards, exposure to various sorts of air pollution, and community-based social vulnerability; we have been working with the support of the California Air Resources Board to develop exactly such a typology. While the geographic nexus between the emitters and the communities receiving benefits might be looser in this scheme – unlike in the surcharge approach – it would be more efficient in achieving health and other benefits (money collected is spent where it is most needed not only where it is collected). Neighborhoods need not be limited to pollution issues in how they spend the funds but could rather improve park space, job training, and other identified needs.

The basic concept of a community benefits fund finds support even amongst some who are critical of any tinkering with carbon market mechanisms (e.g. Schatzki and Stavins 2009). A benefits fund is also aligned with the notion of compensating lower-income consumers for the higher energy prices that will be triggered by limiting carbon (Boyce and Riddle 2007). All of this would be made more possible if the state was to take up the recommendation of the Economic and Allocation Advisory Committee (EAAC 2010) that indicated that the Air Resources Board "rely principally, and perhaps exclusively, on auctioning as the method for distributing allowances." A full auction would make the system much closer to a carbon fee system and, as EAAC notes, have several other attractive features. Finally, legislation currently in progress in the state legislature (AB 1405) could make a community benefits fund real: it would force the state to direct a portion of any revenues generated under AB 32 – whether from fees or auction revenues – to communities that are historically disadvantaged in terms of both economic and environmental health.

There are therefore real policy opportunities to close the climate gap. At the very least, CARB needs to create a mechanism for monitoring allowance allocations and trades or fee payments, and assess the impact on co-pollutants as facilities make their choice about how to contribute to achieving the overall cap. The research above has demonstrated a point that is really quite obvious: cap-and-trade is inherently unequal – and if it weren't, no trades would take place. Given that, we should all be interested in exactly the pattern of geographic inequality that will emerge and whether it will exacerbate or ameliorate the pattern of environmental disparity that has marked the state and helped to produce the climate gap.

Minding the Gap

California is at a crossroads. With a world in peril and public health at risk, the state has chosen to lead in the global fight to reduce greenhouse gas emissions, rescue our economy, and protect the planet for generations to come.

The state has also chosen to make equitable environmental outcomes central to its approach to these issues. An Environmental Justice Advisory Committee (EJAC) was written explicitly into the AB 32 legislation and while there have been tensions between the committee and the state, particularly related to cap-and-trade as a viable GHG reduction strategy, there is clearly a shared concern that implementation of AB 32 be done in a way that is fair to all communities.

As California takes steps to respond to the climate crisis, closing the climate gap needs to be a higher priority, starting with making sure GHG reduction policies don't leave anyone behind and don't unintentionally widen the climate gap.

The research reviewed here suggests that the concerns of environmental justice advocates about the unequal impacts of cap-and-trade are not misplaced. The major facilities that will be regulated under any carbon reduction program are more frequently located near people of color and lower-income communities, with a handful of petroleum refineries making a significant contribution to the pattern of inequity. While we cannot predict the exact direction of trades, we do know that it is quite possible that an unconstrained market system will, at a minimum, fail to realize the full benefits of co-pollutant reduction and, at a maximum, worsen the current pattern of inequality.

Ensuring that a market-oriented regulatory system – either cap-and-trade or fees – avoids widening the climate gap is essential. A series of simple strategies – prohibit facilities from making trades with and restrict allowance allocations and offset uses with significant health impacts, impose a surcharge in locations where health benefits could be high, limit trades by zone depending on overall pollution burden, or develop a compensation system that could redirect revenues to climate gap communities to address health and other concerns – are all relatively simple to design and implement and should be considered as part of the policy menu. In addition, the state should consider the development of a monitoring system that tracks trades and offset use (or fee payments) to ensure that a market system does not contribute to the inequities depicted here, and to enable other mitigation policies to be triggered as needed.

The stakes are high and the time is now. In order to successfully make the monumental economic and social shifts required to address the climate change challenge, we need to engage diverse constituencies in ways that take into account everyone's needs and health concerns. New and more inclusive GHG reduction policies can protect our communities and the planet. California faces a big challenge but also a big opportunity. We are poised to lead not only in curbing climate change, but also in closing the climate gap. As other states and the nation move forward, the impact of this work will multiply. We should get this right – and fair – from the beginning.

Notes

[1] See California Health & Safety Code §38570(b).

[2] Ibid. §38570(b)(2).

[3] For a description of how the dataset was constructed, see "Appendix A: Co-Benefits Analysis Methods" at: http://www.nrdc.org/globalWarming/boosting/boostinga.pdf

[4] The emissions inventory can be accessed at: http://www.arb.ca.gov/ei/emissiondata.htm

[5] The 2008 GHG emissions data can be accessed at: http://www.arb.ca.gov/cc/reporting/ghg-rep/ghg-reports.htm

[6] TeleAtlas, 2007.

[7] Health endpoint factors are the estimated number of tons per year of a particular pollutant that can be associated with each case of a health endpoint (in this case premature mortality) in within a particular geographic area (in this case air basins). See www.arb.ca.gov/planning/gmerp/march21plan/docs/health_analysis_supplement.pdf for the more information, including the health endpoint factors for each air basin.

[8] See USEPA, AIRTrends 1995 Summary at: http://www.epa.gov/airtrends/aqtrnd95/pm10.html

[9] For Figure 5, in order to simplify the graph, the racial composition of people living near the different facility types at the five mile distance is not shown. It was chosen as the distance band to omit because it had a racial composition that was nearly identical to the composition at the six mile distance band, which is shown.

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Photo Credit

Photos on the front cover from left to right:

Photo by Jesse Marquez.

Photo of Kari Fulton by Ben Powless.

Photo of Communities for a Better Environment (CBE) Wilmington Lead Organizer by PERE.

Executive Summary, Page 1: La Paloma power plant and Exxon Mobile Refinery in Torrance, CA, TeleAtlas, 2010.

Executive Summary, Page 3: Tesoro Wilmington Refinery, 9/25/09, Photo by Jesse Marquez.

Technical Appendix

Constructing the Health Impact Index

Based on Bailey et al. (2008), we used the NO_X and PM_{10} emissions to calculate a health impacts index for each facility, which represents the relative potential health impact of the facilities included in the analysis (see Bailey et al. 2008 for assumptions and limitations). The only difference is that we used PM_{10} rather than total PM because it is considered more closely tied to health endpoints. The NOX and PM_{10} data come from the 2006 ARB Emissions Inventory for stationary sources and can be accessed at: http://www.arb.ca.gov/app/emsinv/emssumcat.php. The index also relies on health endpoint factors which are the estimated number of tons per year of a particular pollutant (here, NO_x and PM_{10}) that can be associated with each case of a health endpoint (here, premature mortality) within a particular geographic area (here, air basins). The formula for the health impacts index is:

$$HI_i = \left(NO_x / HEP_{AB}\right) + \left(PM_{2.5} / HEP_{AB}\right)$$

Where: HI_i = Health Impacts Index

NO_x = NO_x emissions in 2006

$PM_{2.5}$ = PM_{10} emissions in 2006 divided by the ratio of PM_{10} to $PM_{2.5}$

HEP_{AB} = Air basin specific health endpoint factor for premature mortality

Matching Block Groups and Facilities

The challenge of matching neighborhoods and facilities is this: facilities are points in space and block groups are areal units. Mohai and Saha (2006) found in their study of geographic methodology that the method employed to describe the spatial relationship of point-location environmental hazards and surrounding populations is the primary reason for the varied results found in many studies relying on similar data and geographic coverage. The "classic" approach, used in most studies, connects census tracts to a hazardous waste treatment, storage, or disposal facility (TSDF) if such a facility is located within the boundaries of the tract itself, making it a "host tract." This approach does not account for people residing in nearby, but non-host tracts, that could well possibly live, on average, about the same distance from the facility. These discrepancies are particularly important given the tendency for TSDFs to be located near tract boundaries (which are often defined by roads) and the large variation in the size and spatial distribution of populations within census tracts.

Instead, Mohai and Saha recommend a distance-based approach where tracts become associated with a facility if they fall within a specified distance of the facility as measured by either one of the tract boundaries, its centroid, or half of its geographic area. We employ a distance-based approach at the block group level that incorporates population weighing. We specifically drilled down to census block level to get the most geographically detailed population information publicly available and, as noted in the text, estimated the share of each block group's population that fell within each buffer distance of each facility. Thus, rather than expressing the block group-facility association in binary terms (i.e., proximate or not), in cases where a buffer intersects the boundaries of a block group, it is expressed as a percentage or fractional association that is equivalent to the share of the block group population captured. In our opinion, such "population weighting" using block-level population information is important because even at the relatively detailed block group level of geography, an evenly distributed population within the block group is uncommon; half of the area of a block group does not necessarily include half the population. Thus, this method should result in a more accurate representation of the number of people and the characteristics those who live near facilities.

Emissions Categorizations

We chose the PM_{10} emission categories shown in Table 2 based on standard deviations from the mean. The means and standard deviations used were calculated at the block group level for the natural log of the summed emissions from all facilities within six miles of each block group, across all block groups within six miles of any facility. The natural log function is commonly used to normalize measures that exhibit a "long tail" or exponential distribution – which describes the measure of summed emissions.

Among all block groups within six miles of any facility, we defined High Emissions block groups as those with emissions over one standard deviation above, Middle Range block groups as those with emissions within one standard deviation of the mean (plus or minus), and Low Emissions block groups as those with emissions under one standard deviation below the mean.

Constructing the Pollution Disparity Index

The pollution disparity index used in this report, which was calculated at the facility level, can be described as a measure of the contribution each facility makes to the statewide difference in average co-pollutant emissions burden between people of color and non-Hispanic whites from the facilities included in our analysis, for a particular distance from the facilities. The derivation below describes how the statewide difference in emissions burden can be decomposed into the facility-level index. Note that while we used PM_{10} as the pollutant and people of color and non-Hispanic whites as the population groups, by making slight adjustments to the below equation, the index and associated statewide difference in emissions burden could be calculated to reflect disparity in emissions of any other pollutant and/or between any other two population groups defined by race/ethnicity, income, or any other measurable characteristic.

In the derivation shown below, POC stands for total people of color, NHW stands for total non-Hispanic whites, d is distance, i is any facility in California included in the analysis, and CA means for the entire state of California.

Total statewide PM_{10} emissions burden associated with the facilities included in our analysis can be calculated as the population-weighted sum of PM_{10} emissions across all facilities i within a certain distance d (i.e. total person-tons of PM_{10}). Average local PM_{10} emissions burden at distance d, calculated separately for each group, is measured essentially as a simple population-weighted average of PM_{10} emissions across all facilities i, using the population within distance d of each facility as the weight, but with one modification: the sum of the weights (the denominators above) is set to the total California population for each group rather than the sum across facilities. This weighting scheme implicitly sets the PM_{10} emissions to zero for all people beyond distance d of any facility, and is

$$\textit{CA difference in average PM10 burden}_{(POC-NHW)d}$$

$$= [\textit{average } POC\, PM10 \textit{ burden}_d] - [\textit{average } NHW\, PM10 \textit{ burden}_d]$$

$$= \left[\frac{\sum_{i=1}^{n} POC_i \times PM10_{i,d}}{POC_{CA}}\right] - \left[\frac{\sum_{i=1}^{n} NHW_i \times PM10_{i,d}}{NHW_{CA}}\right]$$

$$= \sum_{i=1}^{n}\left[\frac{POC_i \times PM10_{i,d}}{POC_{CA}}\right] - \sum_{i=1}^{n}\left[\frac{NHW_i \times PM10_{i,d}}{NHW_{CA}}\right]$$

$$= \left[\frac{POC_{1,d} \times PM10_{1,d}}{POC_{CA}} + \frac{POC_{2,d} \times PM10_{2,d}}{POC_{CA}} + \ldots \frac{POC_{n,d} \times PM10_{n,d}}{POC_{CA}}\right] - \left[\frac{NHW_{1,d} \times PM10_{1,d}}{NHW_{CA}} + \frac{NHW_{2,d} \times PM10_{2,d}}{NHW_{CA}} + \ldots \frac{NHW_{n,d} \times PM10_{n,d}}{NHW_{CA}}\right]$$

$$= \left[\frac{POC_{1,d} \times PM10_{1,d}}{POC_{CA}} - \frac{NHW_{1,d} \times PM10_{1,d}}{NHW_{CA}}\right] + \left[\frac{POC_{2,d} \times PM10_{2,d}}{POC_{CA}} - \frac{NHW_{2,d} \times PM10_{2,d}}{NHW_{CA}}\right] + \ldots \left[\frac{POC_{n,d} \times PM10_{n,d}}{POC_{CA}} - \frac{NHW_{n,d} \times PM10_{n,d}}{NHW_{CA}}\right]$$

imposed so that disparities are figured relative to the statewide population rather than to the population within distance d of any facility.

While this is not a realistic assumption – in reality PM_{10} and other emissions disperse and de-concentrate at varying rates around a facility – in lieu of "fate-and-transport" modeling, this is our best estimate. Our method tests a variety of distances under the assumption that the PM_{10} concentration is constant within each buffer and zero outside the buffer. If similar disparities are found across distance bands and there is a similar composition of sectors and facilities that are driving disparity at each distance, then we expect a more sophisticated model would draw similar conclusions to those drawn from this methodology.

In the last line of the derivation, each bracketed term represents the contribution (positive or negative) of each facility i to the overall statewide difference in person-tons of PM_{10} between people of color and non-Hispanic whites, and is what we have termed the pollution disparity index. A positive or negative index value is determined by the representation of each group near the facility; if the share of the state's people of color residing near the facility is greater than the share of the state's non-Hispanic white population residing near the facility, then term will be positive. If reverse is true, it will be negative.

While the statewide difference expresses environmental disparity in co-pollutant emissions from the facilities included in our analysis at the state level, the pollution disparity index tells of each facility's contribution to that measure of statewide disparity, which is experienced at the local level. The facility-level index can be summed up across any group of facilities by type or locale (e.g., across all power plants in the state or across all facilities in a particular county, city, or neighborhood) to get a measure of the contribution that group of facilities makes to the statewide difference.

Finally, we emphasize that the approximation of "emissions burden" we use here is just that – an approximation. "Exposure" as used in the public health field typically implies modeling of emissions to determine concentrations at the neighborhood level, taking into account distance from the facility, how emissions are released, and local wind and atmospheric patterns, among other factors. Instead, emissions burden and the pollution disparity index rely on a rough approximation based on total co-pollutant emissions and the number of people within a particular distance from the facility.

About the Research Team

DR. RACHEL MORELLO-FROSCH is Associate Professor in the Department of Environmental Science, Policy and Management and the School of Public Health at the University of California, Berkeley. Dr. Morello-Frosch's research examines race and class determinants of environmental health among diverse communities in the United States. A focus of her work is the relationship between segregation and environmental health inequalities associated with air pollution, children's environmental health, and the intersection between economic restructuring and community environmental health. Currently, Dr. Morello-Frosch collaborates with colleagues and environmental justice organizations to research and address climate justice issues, including the social equity implications of proposed greenhouse gas reduction strategies in California associated with the AB 32 Scoping Plan; and disparities in community capacity to adapt to environmental impacts of climate change. Her work is funded by the National Institutes of Health, the National Science Foundation, the California Environmental Protection Agency, the California Wellness Foundation, and the California Endowment, among others. Dr. Morello-Frosch currently serves on the Health Impacts Assessment Advisory Committee for the implementation of the AB 32 Scoping Plan.

DR. MANUEL PASTOR is Professor of Geography and American Studies & Ethnicity at the University of Southern California where he also serves as Director of the Program for Environmental and Regional Equity (PERE) and co-Director of USC's Center for the Study of Immigrant Integration (CSII). Pastor holds an economics Ph.D. from the University of Massachusetts, Amherst, and has received fellowships from the Danforth, Guggenheim, and Kellogg foundations and grants from the Irvine Foundation, the Rockefeller Foundation, the Ford Foundation, the National Science Foundation, the Hewlett Foundation, the MacArthur Foundation, the California Environmental Protection Agency, the California Wellness Foundation, and many others. His most recent book, co-authored with Chris Benner and Martha Matsuoka, is *This Could Be the Start of Something Big: How Social Movements for Regional Equity are Reshaping Metropolitan America* (Cornell University Press, 2009). Dr. Pastor served on the Regional Targets Advisory Committee, a group advising the California Air Resources Board on methods to set goals for the reduction of greenhouse gas emissions through better land use planning.

DR. JAMES L. SADD is Professor of Environmental Science at Occidental College, Los Angeles, California. He earned his doctorate in geology at the University of South Carolina, Columbia. His research includes spatial analysis using geographic information systems and remote sensing tools, particularly to evaluate questions related to environmental exposure. His recent research is supported by contracts and grants from the Andrew W. Mellon Foundation, US Army Corps of Engineers, US Navy Office of Naval Research, NOAA SeaGrant. Dr. Sadd served on the Nationally Consistent Environmental Justice Screening Approaches Work Group, advising on the EPA's Environmental Justice Strategic Enforcement Screening Tool (EJSEAT).

JUSTIN SCOGGINS is a data analyst at the Program for Environmental and Regional Equity at the University of Southern California. Since graduating with an MS in applied economics and finance from the University of California, at Santa Cruz, he has been assisting with research around issues of social justice, specializing in statistical analysis of patterns of environmental injustice, labor market intermediaries, and regional equity. He has published articles in both the Journal of Urban Affairs and the Journal of Planning Education and Research.

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Minding the Climate Gap Report

BY ELECTRONIC MAIL

COMMUNITIES FOR A
BETTER
ENVIRONMENT

23 November 2015
Revised 23 November 2015

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Re: **Supplemental Comment on Air District Staff Proposal, Rules 12-15 and 12-16; Evidence of Localized Bay Area Refinery GHG and PM$_{2.5}$ Emission Impact**

Dear Mssrs. Nudd and Stevenson,

Data the Air District reports elsewhere document a substantial long-term increase in Bay Area refinery emissions of GHG and PM$_{2.5}$ that co-emit from refinery fuel combustion. EIA data show that refined fuels demand cannot explain the reported emissions increase. Peer reviewed science shows that refining lower quality oil contributed to this emissions increase and could further increase emissions from Bay Area refineries if their current, declining, crude oil supply is replaced with bitumen-derived ‘tar sands’ oil.

Forecasts the Air District reports elsewhere show that Bay Area refinery GHG and PM$_{2.5}$ emissions could further increase. The peer reviewed science shows that Bay Area refinery emissions could greatly exceed even these forecasts if the refiners replace their declining current oil supply with bitumen-derived tar sands oil. In fact, industry reports document plans to replace Bay Area (and California) refiners’ declining current oil supplies with that tar sands oil—if the resultant emissions increase is allowed.

Moreover, those industry-reported plans include a major expansion of Bay Area oil train traffic that—since Bay Area refineries cannot process very large amounts of light shale oils efficiently—could be allowed here ***if*** the emissions increase from refining the large amounts of tar sands oil these trains would deliver is allowed.

The foregoing is summarized from CBE’s 21 October 2015 comments 1–10.

CBE believes that the Air District Staff has improperly rejected enforceable limits set to current actual emission rates in part because the Staff has not considered adequately, and has not informed the public and its Board about, the data and information summarized above, and the following data and information:

11. Bay Area oil refineries contribute to serious PM air pollution impacts.

Analysis the Air District reports elsewhere estimates that air pollution kills ≈ 2,000 to 3,000 Bay Area residents each year, $PM_{2.5}$ causes the "vast majority" of these premature deaths, and health impacts from air pollution cost the region's economy "multiple billions of dollars" each year. (Attachment 4 to CBE's 21 Oct. Comment at pp. 26–27.)

A table from the Air District web site indicating that the region does not attain State ambient air quality standards for $PM_{2.5}$, PM_{10} and ozone, and also remains designated as in "nonattainment" of national ambient air quality standards (NAAQS) for $PM_{2.5}$ and ozone, is appended hereto as Attachment 36.[36] A World Health Organization (WHO) summary of its health-based ambient air PM criteria is appended as Attachment 37.[37] Attachments 36 and 37 show that WHO's health-based ambient air criteria for $PM_{2.5}$ (10 $\mu g/m^3$ annual mean; 25 $\mu g/m^3$ 24-hour mean) are more protective than the NAAQS (12 $\mu g/m^3$ annual mean; 35 $\mu g/m^3$ 24-hour mean).

California Air Resources Board (ARB) data for 24-hour $PM_{2.5}$ air concentrations that exceeded NAAQS and WHO criteria during May 2012–April 2015 at the five nearest $PM_{2.5}$ NAAQS monitors to Bay Area refineries are appended hereto as Attachment 38.[38] The table below summarizes these data. $PM_{2.5}$ exceeded one or both health criteria a total of 156 times at these five monitoring stations collectively on 66 days in this period. $PM_{2.5}$ exceeded the WHO health criterion more frequently than once each 17 days, on average over these three years. On most of these days (40 of 66), criteria were exceeded at multiple locations, and the vast majority of these days (61 of 66), were in winter. These observations are consistent with the accumulation of local emissions in nearby air that the Air District reports elsewhere. Atmospheric conditions that Air District Staff describe in Attachment 4 as "stagnation," which occur most frequently in the Bay Area in winter, trap air pollution close to emission sources, thereby increasing the effect of strong local emission sources that elevates $PM_{2.5}$ air concentrations near these sources.

This evidence demonstrates that the refinery emissions documented in CBE's 21 October 2015 comments 1–10 contribute to a serious air pollution and health problem.

Ambient air $PM_{2.5}$ concentrations that exceeded the 25 µg/m^3 World Health Organization (WHO) and 35 µg/m^3 National Ambient Air Quality Standard (NAAQS) criteria for 24–hour exposures at NAAQS $PM_{2.5}$ monitors nearest to Bay Area refineries, May 2012–Apr 2015.[a]

		24-hour average $PM_{2.5}$ ambient air data	
Date	NAAQS Monitoring Station	(µg/m^3)	(health criteria exceeded)
16 November 2012	Concord–Treat Blvd.	32.2	WHO
16 November 2012	San Rafael	25.9	WHO
5 January 2013	Concord–Treat Blvd.	27.6	WHO
5 January 2013	San Rafael	28.5	WHO
5 January 2013	Vallejo–Tuolumne St.	28.6	WHO
15 January 2013	Vallejo–Tuolumne St.	26.7	WHO
16 January 2013	Oakland–West	33.2	WHO
16 January 2013	San Rafael	26.3	WHO
16 January 2013	Vallejo–Tuolumne St.	32.8	WHO
17 January 2013	Oakland–West	29.8	WHO
17 January 2013	San Rafael	25.5	WHO
17 January 2013	Vallejo–Tuolumne St.	25.2	WHO
22 January 2013	Oakland–West	28.1	WHO
22 January 2013	San Rafael	26.5	WHO
23 January 2013	Concord–Treat Blvd.	36.2	WHO and NAAQS
23 January 2013	Oakland–West	37.4	WHO and NAAQS
23 January 2013	San Pablo–Rumrill Blvd.	38.7	WHO and NAAQS
23 January 2013	San Rafael	31.5	WHO
1 February 2013	Oakland–West	28.5	WHO
1 May 2013	Oakland–West	27.3	WHO
1 June 2013	Oakland–West	25.1	WHO
4 July 2013	Oakland–West	29.2	WHO
29 July 2013	Oakland–West	29.0	WHO
30 July 2013	Oakland–West	25.9	WHO
30 July 2013	San Pablo–Rumrill Blvd.	31.1	WHO
30 July 2013	San Rafael	26.1	WHO
30 July 2013	Vallejo–Tuolumne St.	26.0	WHO
24 November 2013	Vallejo–Tuolumne St.	31.7	WHO
25 November 2013	Oakland–West	25.7	WHO
25 November 2013	San Pablo–Rumrill Blvd.	25.2	WHO
25 November 2013	Vallejo–Tuolumne St.	29.9	WHO
27 November 2013	Oakland–West	29.1	WHO
27 November 2013	San Pablo–Rumrill Blvd.	25.8	WHO
5 December 2013	Vallejo–Tuolumne St.	26.2	WHO
12 December 2013	Oakland–West	25.7	WHO
12 December 2013	San Pablo–Rumrill Blvd.	25.7	WHO
13 December 2013	Oakland–West	26.9	WHO
13 December 2013	Vallejo–Tuolumne St.	25.2	WHO
14 December 2013	Vallejo–Tuolumne St.	38.0	WHO and NAAQS
15 December 2013	Oakland–West	31.8	WHO
15 December 2013	San Pablo–Rumrill Blvd.	29.8	WHO
15 December 2013	San Rafael	26.5	WHO
15 December 2013	Vallejo–Tuolumne St.	33.7	WHO

Ambient air $PM_{2.5}$ concentrations that exceeded the 25 µg/m^3 World Health Organization (WHO) and 35 µg/m^3 National Ambient Air Quality Standard (NAAQS) criteria for 24–hour exposures at NAAQS $PM_{2.5}$ monitors nearest to Bay Area refineries, May 2012–Apr 2015.[a] *Continued.*

		24-hour average $PM_{2.5}$ ambient air data	
Date	NAAQS Monitoring Station	(µg/m^3)	(health criteria exceeded)
16 December 2013	Oakland–West	25.7	WHO
16 December 2013	Vallejo–Tuolumne St.	28.8	WHO
17 December 2013	Concord–Treat Blvd.	29.5	WHO
17 December 2013	Oakland–West	42.7	WHO and NAAQS
17 December 2013	San Pablo–Rumrill Blvd.	41.2	WHO and NAAQS
17 December 2013	San Rafael	44.9	WHO and NAAQS
17 December 2013	Vallejo–Tuolumne St.	38.7	WHO and NAAQS
22 December 2013	Oakland–West	25.1	WHO
22 December 2013	Vallejo–Tuolumne St.	31.9	WHO
23 December 2013	Oakland–West	32.5	WHO
23 December 2013	San Pablo–Rumrill Blvd.	31.0	WHO
23 December 2013	San Rafael	32.6	WHO
23 December 2013	Vallejo–Tuolumne St.	39.3	WHO and NAAQS
24 December 2013	Oakland–West	32.2	WHO
24 December 2013	San Rafael	29.0	WHO
24 December 2013	Vallejo–Tuolumne St.	31.3	WHO
25 December 2013	Oakland–West	30.0	WHO
25 December 2013	San Pablo–Rumrill Blvd.	27.4	WHO
25 December 2013	Vallejo–Tuolumne St.	36.5	WHO and NAAQS
26 December 2013	Oakland–West	26.1	WHO
27 December 2013	Oakland–West	29.6	WHO
30 December 2013	Concord–Treat Blvd.	26.3	WHO
30 December 2013	Oakland–West	26.2	WHO
30 December 2013	San Pablo–Rumrill Blvd.	33.3	WHO
30 December 2013	San Rafael	44.4	WHO and NAAQS
30 December 2013	Vallejo–Tuolumne St.	35.5	WHO
31 December 2013	Oakland–West	26.2	WHO
31 December 2013	San Pablo–Rumrill Blvd.	30.4	WHO
31 December 2013	San Rafael	25.7	WHO
31 December 2013	Vallejo–Tuolumne St.	42.6	WHO and NAAQS
1 January 2014	Oakland–West	38.8	WHO and NAAQS
1 January 2014	Vallejo–Tuolumne St.	39.6	WHO and NAAQS
2 January 2014	Oakland–West	25.7	WHO
3 January 2014	Oakland–West	25.7	WHO
3 January 2014	Vallejo–Tuolumne St.	30.7	WHO
6 January 2014	Oakland–West	25.8	WHO
6 January 2014	San Pablo–Rumrill Blvd.	26.4	WHO
7 January 2014	Oakland–West	25.2	WHO
17 January 2014	Oakland–West	33.8	WHO
17 January 2014	San Pablo–Rumrill Blvd.	29.6	WHO
17 January 2014	San Rafael	30.8	WHO
17 January 2014	Vallejo–Tuolumne St.	31.8	WHO

Ambient air $PM_{2.5}$ concentrations that exceeded the 25 µg/m^3 World Health Organization (WHO) and 35 µg/m^3 National Ambient Air Quality Standard (NAAQS) criteria for 24–hour exposures at NAAQS $PM_{2.5}$ monitors nearest to Bay Area refineries, May 2012–Apr 2015.[a]
Continued.

Date	NAAQS Monitoring Station	24-hour average $PM_{2.5}$ ambient air data (µg/m^3)	(health criteria exceeded)
19 January 2014	Oakland–West	27.2	WHO
19 January 2014	San Pablo–Rumrill Blvd.	25.6	WHO
20 January 2014	Oakland–West	25.5	WHO
24 January 2014	Concord–Treat Blvd.	30.6	WHO
24 January 2014	Oakland–West	30.9	WHO
24 January 2014	San Pablo–Rumrill Blvd.	38.2	WHO and NAAQS
24 January 2014	San Rafael	38.1	WHO and NAAQS
25 January 2014	Oakland–West	25.4	WHO
6 November 2014	Vallejo–Tuolumne St.	29.7	WHO
27 November 2014	Concord–Treat Blvd.	25.1	WHO
27 November 2014	Oakland–West	26.1	WHO
27 November 2014	San Pablo–Rumrill Blvd.	28.2	WHO
27 November 2014	San Rafael	26.8	WHO
27 November 2014	Vallejo–Tuolumne St.	30.9	WHO
9 December 2014	Vallejo–Tuolumne St.	29.5	WHO
28 December 2014	Vallejo–Tuolumne St.	26.9	WHO
2 January 2015	San Rafael	26.7	WHO
2 January 2015	Vallejo–Tuolumne St.	30.2	WHO
3 January 2015	Concord–Treat Blvd.	26.1	WHO
3 January 2015	Oakland–West	33.7	WHO
3 January 2015	San Pablo–Rumrill Blvd.	29.6	WHO
3 January 2015	San Rafael	30.2	WHO
3 January 2015	Vallejo–Tuolumne St.	38.0	WHO and NAAQS
4 January 2015	Concord–Treat Blvd.	27.4	WHO
4 January 2015	Oakland–West	34.8	WHO
4 January 2015	San Pablo–Rumrill Blvd.	32.1	WHO
4 January 2015	San Rafael	31.3	WHO
4 January 2015	Vallejo–Tuolumne St.	32.5	WHO
5 January 2015	Oakland–West	25.8	WHO
5 January 2015	San Pablo–Rumrill Blvd.	26.4	WHO
5 January 2015	Vallejo–Tuolumne St.	28.6	WHO
6 January 2015	Oakland–West	36.1	WHO and NAAQS
6 January 2015	San Pablo–Rumrill Blvd.	26.5	WHO
6 January 2015	San Rafael	27.7	WHO
6 January 2015	Vallejo–Tuolumne St.	28.9	WHO
7 January 2015	Oakland–West	25.2	WHO
8 January 2015	Concord–Treat Blvd.	31.0	WHO
8 January 2015	Oakland–West	38.7	WHO and NAAQS
8 January 2015	San Pablo–Rumrill Blvd.	31.8	WHO
8 January 2015	San Rafael	34.8	WHO
8 January 2015	Vallejo–Tuolumne St.	41.4	WHO and NAAQS
9 January 2015	Oakland–West	29.9	WHO

Ambient air $PM_{2.5}$ concentrations that exceeded the 25 µg/m^3 World Health Organization (WHO) and 35 µg/m^3 National Ambient Air Quality Standard (NAAQS) criteria for 24–hour exposures at NAAQS $PM_{2.5}$ monitors nearest to Bay Area refineries, May 2012–Apr 2015.[a] *Continued.*

		24-hour average $PM_{2.5}$ ambient air data	
Date	NAAQS Monitoring Station	(µg/m^3)	(health criteria exceeded)
9 January 2015	Vallejo–Tuolumne St.	29.5	WHO
10 January 2015	Vallejo–Tuolumne St.	29.7	WHO
11 January 2015	Vallejo–Tuolumne St.	27.0	WHO
14 January 2015	Concord–Treat Blvd.	28.3	WHO
14 January 2015	San Pablo–Rumrill Blvd.	31.7	WHO
14 January 2015	San Rafael	35.1	WHO
14 January 2015	Vallejo–Tuolumne St.	39.1	WHO and NAAQS
15 January 2015	Concord–Treat Blvd.	29.6	WHO
15 January 2015	Oakland–West	36.1	WHO and NAAQS
15 January 2015	San Pablo–Rumrill Blvd.	33.2	WHO
15 January 2015	San Rafael	36.3	WHO and NAAQS
15 January 2015	Vallejo–Tuolumne St.	31.9	WHO
16 January 2015	Concord–Treat Blvd.	28.1	WHO
16 January 2015	Oakland–West	32.9	WHO
16 January 2015	San Pablo–Rumrill Blvd.	31.6	WHO
16 January 2015	San Rafael	36.0	WHO and NAAQS
16 January 2015	Vallejo–Tuolumne St.	30.7	WHO
23 January 2015	Vallejo–Tuolumne St.	29.4	WHO
24 January 2015	San Rafael	30.5	WHO
24 January 2015	Vallejo–Tuolumne St.	28.2	WHO
26 January 2015	Vallejo–Tuolumne St.	25.1	WHO
28 January 2015	Vallejo–Tuolumne St.	26.1	WHO
1 February 2015	Vallejo–Tuolumne St.	32.6	WHO
2 February 2015	Oakland–West	26.7	WHO
2 February 2015	San Rafael	29.5	WHO
2 February 2015	Vallejo–Tuolumne St.	32.0	WHO
4 February 2015	Concord–Treat Blvd.	25.6	WHO
4 February 2015	San Pablo–Rumrill Blvd.	26.2	WHO
4 February 2015	San Rafael	31.0	WHO

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[a] Data from California Air Resources Board; www.arb.ca.gov/adam/weekly/weekly2.php; *see* Attachment 38. San Pablo and W. Oakland stations began reporting data on December 12th and 18th, 2012, respectively.

12. Bay Area oil refineries cause disparately greater PM emissions locally.

As stated, strong local emission sources elevate $PM_{2.5}$ air concentrations locally, especially during stagnant atmospheric conditions that trap emissions near their sources. A report by former ARB advisors that found oil refineries are 11 of the worst 15 major industrial GHG co-pollutant emitters in California, as ranked by population-weighted PM emission burden at 2.5 miles from the facilities, is appended hereto as Attachment 39.[39]

Areal refinery source strength—emissions per area (e.g., mile^2) within a given boundary around the source—was calculated from Air District data for the same range of boundary distances assessed in Attachment 39, and compared with the average for *all* emission sources within the Bay Area as a whole, as detailed in Attachment 40.[40] The table below shows areal source strengths for $PM_{2.5}$ and the $PM_{2.5}$ precursors NO_x and SO_2. For example, the Bay Area average $PM_{2.5}$ source strength (3.19 annual t/mile^2) is based on 17,885 tons emitted by all sources in the Bay Area divided by its area (5,600 miles^2); the refineries source strength at the 0.5 miles boundary (250 t/mile^2) is based on 985 tons emitted by refineries divided by 3.93 miles^2, their collective 0.5-mile-radius area. These source strengths are averages: air emission plumes vary in direction and concentration.

Areal refinery emission source strength at 0.5–6 miles, in emissions per square mile and as a percentage of the regional average for all sources in the Bay Area Air District.[a]

Pollutant Emission	Bay Area Sources	Areal Boundary	Areal source strength at boundary (avg.)	
			Annual tons/mile^2	% of Bay Area avg.
$PM_{2.5}$	All sources	AQMD jurisdiction	3.19	—
$PM_{2.5}$	Oil refineries	0.5 miles radius	250	≈ 7,800%
$PM_{2.5}$	Oil refineries	2.5 miles radius	10.0	≈ 310%
$PM_{2.5}$	Oil refineries	6.0 miles radius	1.74	≈ 54%
NO_x	All sources	AQMD jurisdiction	22.6	—
NO_x	Oil refineries	0.5 miles radius	1,080	≈ 4,800%
NO_x	Oil refineries	2.5 miles radius	43.4	≈ 190%
NO_x	Oil refineries	6.0 miles radius	7.54	≈ 33%
SO_2	All sources	AQMD jurisdiction	1.89	—
SO_2	Oil refineries	0.5 miles radius	1,380	≈ 73,000%
SO_2	Oil refineries	2.5 miles radius	55.3	≈ 2,900%
SO_2	Oil refineries	6.0 miles radius	9.60	≈ 510%

[a] Based on reported emissions and area within boundary: Emissions from BAAQMD inventories; refinery boundary distances after Pastor et al., 2010; jurisdiction area from BAAQMD. *See* Attachment 40 for details.

Review of the table reveals substantial refinery source strength at all distances compared. This is true for $PM_{2.5}$, NO_x and SO_2. The areal source strength of Bay Area refineries for these pollutants ranges from ≈ 48–730 *times* the Bay Area average for all sources at 0.5 miles, to ≈ 2–29 *times* this average at 2.5 miles, to 33–510% of the Bay Area average at six miles away from refineries. Note that these values are roughly additive—for example, the 33% value for refineries in the table represents an average total source strength that is ≈ 133% of the Bay Area average. Thus, all the data shown in the table indicate that refineries contribute significantly to locally elevated emissions.

This evidence demonstrates that the refineries cause a disparately severe local $PM_{2.5}$ air pollution emission impact.

13. Bay Area refinery emissions contribute substantially to disparately greater PM pollution of the ambient air locally.

A 2012 paper showing that refineries affect the PM trace element chemistry of urban ambient air 2–8 kilometers downwind is appended hereto as Attachment 41.[41] A 2010 paper showing that metalliferous ultra-fine particulate matter (UFPM) emissions from refineries and other industries can alter atmospheric chemistry over “whole towns and cities” is appended hereto as Attachment 42.[42] A 2012 paper showing that emissions from oil refining and other industries are the main cause of UFPM air pollution episodes in Huelva, Spain is appended hereto as Attachment 43.[43] The analyses of refinery air pollution outside the Bay Area that is reported in attachments 41–43 further support the chemical “fingerprinting” analysis linking locally elevated ambient $PM_{2.5}$ to a Bay Area refinery source that is reported below.

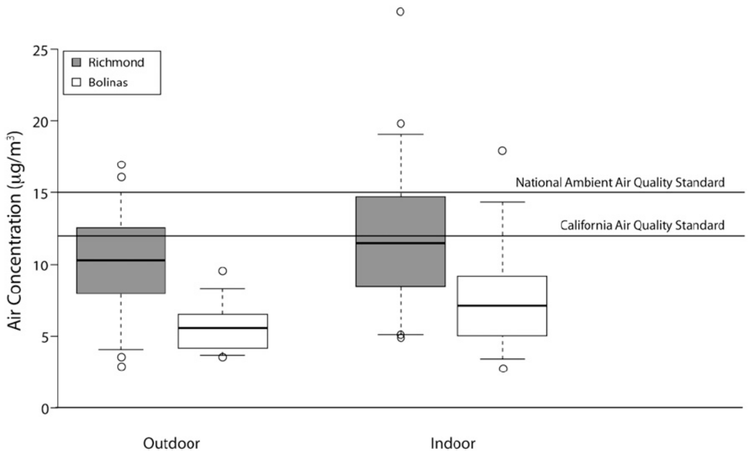
A 2009 paper that, among other things, documents locally elevated ambient air $PM_{2.5}$ levels in communities near the Chevron Richmond refinery, and shows by chemical “fingerprinting” that heavy oil combustion at the refinery and port account for this elevated air pollution, is appended hereto as Attachment 44.[44] A 2005 report that documents a statistically significant link between episodic emissions from Bay Area refineries and elevated SO_2 and H_2S ambient air levels at regional monitors, and even higher air levels at closer-in fence line monitors is appended hereto as Attachment 45.[45] A 2006 Air District Staff report documenting air dispersion modeling that corroborates the localized impacts shown in Attachment 45 is appended hereto as Attachment 46.[46] A 2013 report on the 6 August 2012 catastrophic pipe failure and refinery fire at Richmond indicating that ≈ 15,000 residents sought emergency medical care following exposures to the massive PM plume from this fire is appended hereto as Attachment 47.[47]

The evidence in attachments 36–47 strongly supports the conclusion that Bay Area refineries contribute substantially to disparately severe local $PM_{2.5}$ air pollution.

14. Ambient air data alone may underestimate the severity of refinery impacts because refinery emissions penetrate indoor environments.

The most uniquely important data and information reported in Attachment 44 is from intensive multi-pollutant monitoring of *indoor* household air at 50 Bay Area sites, including 40 sites near the Richmond refinery and ten control sites in Bolinas. Analysis of the resultant data showed that outdoor air pollution, including the elevated local air pollution that was caused by the refinery and port, penetrated indoors.

Moreover, some important air pollutants reached higher air concentrations indoors than outdoors—and reached higher indoor air concentrations in the refinery-impacted sites than in the control sites. This effect is illustrated for $PM_{2.5}$ in the chart entitled “Figure 1” in Attachment 44 that is excerpted below.



Note. Solid lines are medians; boxes are interquartile ranges; vertical lines are 5th and 95th percentiles; circles are extreme data points below the 5th percentile and above the 95th percentile; and horizontal dotted lines represent annual federal and state ambient air quality standards for $PM_{2.5}$.

FIGURE 1—Levels of fine particulate matter ($PM_{2.5}$) in homes in Richmond and Bolinas, CA: 2006.

Excerpted from Brody et al., Attachment 44. (NAAQS shown revised in 2012 to 12 µg/m^3 per Att. 36.)

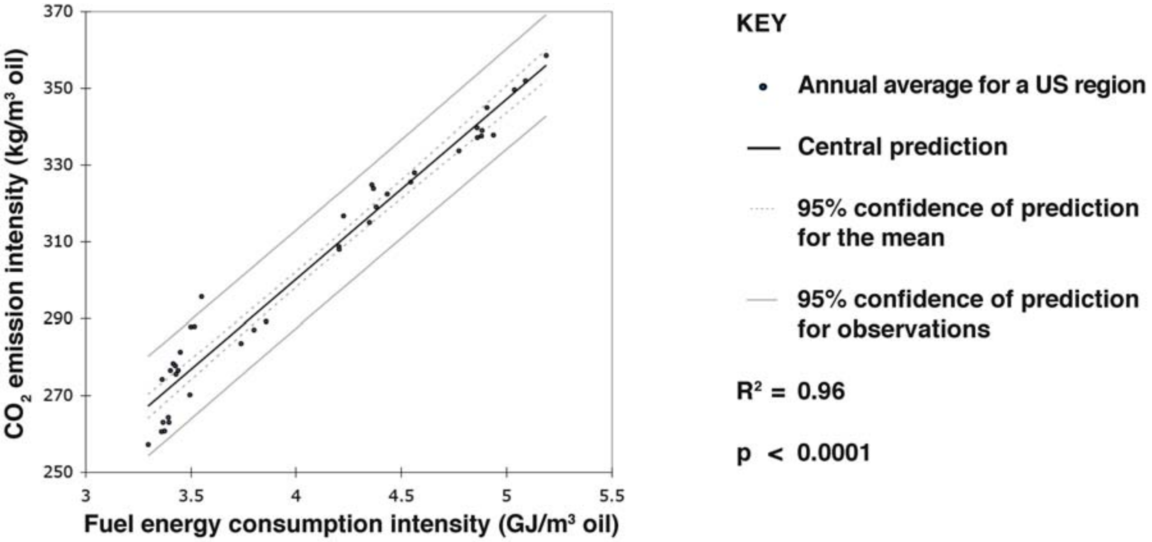
As shown in the chart, indoor air levels of $PM_{2.5}$ exceeded the State's ambient air quality standard at nearly half of the refinery-impacted sites, and exceeded 10 µg/m^3, the annual average health criterion set by WHO, at more than half of the refinery-impacted sites. This finding is based on the measurements reported in Attachment 44, which were taken in the summer months. Bay Area $PM_{2.5}$ levels are well known to be generally lower in summer and higher in winter, so these summertime data may underestimate actual indoor exposures. In any case, this evidence for indoor $PM_{2.5}$ air pollution levels even higher than the levels outdoors is especially important because people on average spend most (≈ 90%) of our time indoors. But ambient air, by definition, is outdoor air. Thus, this evidence of indoor $PM_{2.5}$ air concentrations that are higher than outdoor $PM_{2.5}$ air concentrations at refinery-impacted Bay Area sites indicates that ambient air data alone may underestimate the localized health impacts of refinery emissions here.

15. Increasing refinery GHG emissions would increase unregulated local health hazards from toxic GHG co-pollutant emissions.

Attachments 4, 6, 42, and 43 demonstrate that refineries emit environmentally significant amounts of UFPM that—compared with coarser PM—carries higher concentrations of toxins, penetrates deeper into the lungs, bloodstream, and cells to deliver those toxins, is more abundant and concentrated near its sources, and may in fact be even more toxic.

PM co-emits along with GHGs from Bay Area refinery combustion sources, and refinery PM emissions generally increase along with GHG emissions, as shown by comments 1–6 and attachments 1–20. Attachments 6, 42, and 43 further confirm the co-emission of UFPM with other PM from refineries. Indeed, basic engineering and combustion principles dictate that, like other ubiquitous fossil fuel combustion products, UFPM, $PM_{2.5}$, PM_{10} and CO_2 will co-emit from oil refinery combustion sources. Current industry plans would increase those emissions through a switch to processing tar sands oil that would further increase the energy intensity and fuel combustion intensity of Bay Area refineries, as documented by comments 1–9 and attachments 1–33.

A statistical analysis report on a comparison of actual, observed fuel combustion energy intensity and GHG emission intensity data from operating refineries across 97% of the U.S. industry over ten years is appended hereto as Attachment 48.[48] The data analyzed are from Attachment 13. The analysis finds a strong, positive, quantitatively predictable relationship between the CO_2 emission intensities and fuel energy consumption intensities of refineries. This finding is illustrated in the chart below.



Increase in average refinery CO_2 emission intensity with increasing refinery fuel energy consumption intensity across four U.S. regions and ten years. *Source:* Attachment 48.

Bay Area refinery emissions of UFPM are unregulated because, as the Air District Staff admits, its industrial PM emission monitoring and control requirements are set up to "measure the mass of particles" only, and "UFPM is negligible on a mass basis." (*See* Attachment 4 at 104.) Moreover, "hot spot" impacts from other types of refinery PM emissions are unregulated. An appendix to the Office of Environmental Health Hazard Assessment's guidance showing that (except for PM from diesel and gasoline engines), the State Air Toxics Hot Spots Program does *not* require refinery PM emissions to be quantified for health risk assessment is appended hereto as Attachment 49.[49]

In sum, the evidence in attachments 1–49 shows that unregulated local toxicity hazards from $PM_{2.5}$ and UFPM emissions could increase if further increased refinery GHG emissions are allowed. Strong evidence supports the conclusion that enabling refinery GHG emissions to further increase could result in a worsening of disparately severe, localized toxic hazards from increased refinery emissions of GHG co-pollutants.

16. Additional evidence supports past increases in refinery emission rates.

On Friday 20 November 2015, one working day before the Monday 23 November 2015 deadline for this comment, the Air District Staff provided to CBE two pages of charts and tables that are appended hereto in their entirety as Attachment 50.[50] Attachment 50 suggests a continuing increase in PM emissions in 2014, and a slight decrease in GHG emissions from 2008–2014 (it estimates GHG emissions in 2008 that *exceed all estimated and forecast* annual refinery emissions the Air District had reported through *2026* in Attachment 1). However, Attachment 50 provides no detailed supporting data, and, crucially, it omits *any* information on historic emissions before 2007.

Attachment 50 shows increased PM emissions from Chevron's Fluid Catalytic Cracking (FCC) Unit starting in 2009, and increased PM emissions from Shell and Tesoro cooling towers starting in 2014. Air District Staff indicated that these cooling tower emissions are estimated from unmonitored leaks in aging or inadequately leak-proofed equipment.[50] Such unmonitored leaks in aging or poorly maintained cooling towers may be expected to increase over time—and other evidence the Air District has reported elsewhere shows that the Chevron Richmond refinery FCC emissions have increased since 1999.

Excerpts from Air District Authority to Construct, Emission Inventory, and Annual Source Update files for the Chevron Richmond Refinery FCC Unit are appended hereto as Attachment 51.[51] Following Chevron's rebuild and expansion of the FCC, its oil feed and coke burn rates increased substantially, and its PM emissions increased by ≈ 28%, from 1999–2009. (Attachment 51.) These FCC oil feed, FCC coke burn, and FCC $PM_{2.5}$ emission increments are consistent with the impacts of switching to lower quality crude feeds in the U.S. refining industry that are described in Attachment 18.

A report showing that hydrogen plant expansions to refine lower quality crude increased California refinery GHG emissions by ≈ 3 million metric tons/year from 1995–2007 is appended hereto as Attachment 52.[52] A table of refinery GHG emissions reported by the ARB, and separately, estimated from Petroleum Industry Information Act (PIIRA) fuel use data compiled for the analysis in Attachment 16 and the emission factors in Attachment 13, is appended hereto as Attachment 53.[53] These PIIRA data suggest that between the three-year periods 1990–1992 and 2007–2009, statewide refinery GHG emissions increased by ≈ 3.7 million metric tons/year; and the ARB data suggest that between 1990–1992 and 2011–2013, statewide refinery emissions increased by ≈ 2.1 million metric tons/year. (Absolute values of ARB estimates should not be compared to those of PIIRA estimates due to differences in estimation methods; *see* Attachment 53.)

Attachments 51–53 document additional evidence that processing and feedstock changes contributed to increased refinery GHG and PM emissions over the multi-decade period from the 1990s to the present, consistent with the Air District's formally reported data in attachments 1–5 and CBE's comments 1–2. However, omitting *any* information on historic emissions before 2007, the Air District Staff's newly disclosed Attachment 50 presents an incomplete and inaccurate view of historic refinery emission trends.

Conclusion

Data the Air District reports elsewhere document a substantial long-term increase in Bay Area refinery emissions of GHG and $PM_{2.5}$ that co-emit from refinery fuel combustion. (Additional evidence that is reported elsewhere by the Air District and others and is reviewed in Comment 16 directly above further supports this finding.) Peer reviewed science shows that refining lower quality oil contributed to this emissions increase and could further increase emissions from Bay Area refineries if their current, declining, crude oil supply is replaced with bitumen-derived 'tar sands' oil.

Forecasts the Air District reports elsewhere show that Bay Area refinery GHG and $PM_{2.5}$ emissions could further increase. The peer reviewed science shows that Bay Area refinery emissions could greatly exceed even these forecasts if the refiners replace their declining current oil supply with bitumen-derived tar sands oil. In fact, industry reports document plans to replace Bay Area (and California) refiners' declining current oil supplies with that tar sands oil—if the resultant emissions increase is allowed.

Moreover, those industry-reported plans include a major expansion of Bay Area oil train traffic that—since Bay Area refineries cannot process very large amounts of light shale oils efficiently—could be allowed here ***if*** the emissions increase from refining the large amounts of tar sands oil these trains would deliver is allowed.

Bay Area oil refineries cause serious PM air pollution impacts, disparately greater PM emissions locally, and disparately severe PM pollution of the ambient air locally. But ambient air data alone may underestimate the severity of these impacts since refinery emissions penetrate indoor environments. Increasing refinery GHG emissions would increase unregulated local health hazards from toxic GHG co-pollutant emissions.

CBE asks that the Air District revise and recirculate its environmental analysis of rules 12-15 and 12-16 to report, consider, and address adequately the data, information, and significant potential impacts identified in these comments. A safeguard against further increasing refinery emissions is needed without further delay. The Air District, however, proposes no such safeguard that is specific, enforceable upon adoption, and would apply to refineries facility-wide. Therefore, given the absence of any other such safeguard proposal, CBE's September 2015 proposal for limits set to current facility emission rates, and the community-proposed moratorium on permits for projects to enable lower quality oil, should be considered favorably in your revisions.

Respectfully submitted,

Greg Karras
Senior Scientist

Copy: Ken Alex, Office of the Governor
John Gioia, Stationary Source Committee Chair
Air District Board members
Richard Corey, Air Resources Board
Jack Broadbent, Air Pollution Control Officer
Interested organizations and individuals

Attachments**—**<u>*see*</u> attachments list herein below.

Attachments List (*see CBE's 21 October comments for attachments 1–35*).

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[36] Attachment 36. *Air Quality Standards and Attainment Status;* annotated table accessed on 17 November 2015 from the BAAQMD web site; Bay Area Air Quality Management District: San Francisco, CA.

[37] Attachment 37. *WHO Air Quality Guidelines for Particulate Matter, Ozone, Nitrogen Dioxide and Sulfur Dioxide, Global Update 2005: Summary of Risk Assessment;* World Health Organization: Geneva, Switzerland. 2006.

[38] Attachment 38. *Weekly Listing: National 24-Hour PM2.5 Averages;* data reported by CARB for 24-hour average $PM_{2.5}$ concentrations in ambient air, during ten-week periods from May 2012 through April 2015 when a 24-hour average exceeded NAAQS and WHO criteria, at the five NAAQS monitors nearest to Bay Area oil refineries. California Air Resources Board: Sacramento, CA. Data accessed 16 November 2015 from: www.arb.ca.gov/adam/weekly/weekly2.php.

[39] Attachment 39. Pastor et al., 2010. *Minding the Climate Gap: What's at Stake if California's Climate Law isn't Done Right and Right Away;* USC Program for Environmental and Regional Equity: Los Angeles, CA.

[40] Attachment 40. *Areal Refinery Source Strength Calculation Details;* Annotated tables based on BAAQMD data for 2010 emissions and jurisdictional data and the range of refinery source boundary distances from Attachment 39. Includes calculation details and results for $PM_{2.5}$ and precursors (NOx and SO_2) emissions. CBE, 2015. One page.

[41] Attachment 41. Celo et al., 2012. Concentration and Source Origin of Lanthanoids in the Canadian Atmospheric Particulate Matter: A Case Study. *Atmospheric Pollution Research* **3:** 270–278. DOI: 10.5049/APR.2012.030.

[42] Attachment 42. Moreno et al., 2010. Variations in Vanadium, Nickel and Lanthanoid Element Concentrations in Urban Air. *Science of the Total Environment* **408:** 4569–4579. DOI: 10.1016/j.scitotenv.2010.06.016.

[43] Attachment 43. Fernández-Comacho et al., 2012. Ultrafine Particle and Fine Trace Metal (As, Cd, Cu, Pb and Zn) Pollution Episodes Induced by Industrial Emissions in Huelva, SW Spain. *Atmospheric Environment* **61:** 507–517; http://dx.doi.org/10.1016/j.atmosenv.2012.08.003.

[44] Attachment 44. Brody et al., 2009. Linking Exposure Assessment Science with Policy Objectives for Environmental Justice and Breast Cancer Advocacy: The Northern California Household Exposure Study. *American Journal of Public Health* **99**(S3): S600–S609. DOI: 10.2105/AJPH.2008.149088 (Attachment includes Errata corrections).

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[45] Attachment 45. Karras and Hernandez, 2005. *Flaring Hot Spots: Assessment of Episodic Local Air Pollution Associated with Oil Refinery Flaring Using Sulfur as a Tracer;* A CBE report. Communities for a Better Environment (CBE): Oakland and Huntington Park, CA. July 2005.

[46] Attachment 46. Ezersky and Walsh, 2006. *Staff Report, Proposed Amendments to Regulation 12, Miscellaneous Standards of Performance, Rule 12, Flares at Petroleum Refineries;* Bay Area Air Quality Management District: San Francisco, CA. See esp. "Current Flare Emission Estimate" section at pages 6–8.

[47] Attachment 47. *Interim Investigation Report, Chevron Richmond Refinery Fire: Chevron Richmond Refinery; Richmond, California, August 6, 2012;* U.S. Chemical Safety and Hazard Investigation Board: Washington, D.C. Adopted 19 April 2013.

[48] Attachment 48. *Statistical Analysis Report on Comparison of Actual Refinery Fuel Combustion Energy Intensity versus Actual Refinery* CO_2 *Emission Intensity Observed Across 97% of the U.S. Refining Industry: Annual Observations From 1999–2008;* Analysis of data from Attachment 13 (Karras, 2010) by Communities for a Better Environment (CBE). Excel file: includes data, regression, normality test results.

[49] Attachment 49. *Air Toxics Hot Spots Program Guidance Manual for Preparation of Health Risk Assessments Appendix A;* California Office of Environmental Health Hazard Assessment: Sacramento, CA. February 2015. Note that the only PM emissions included in Appendix A-I, the detailed list of substances required to be quantified for HRAs, are PM emissions from diesel engine (p. A-8) and gasoline engine (p. A-10) exhaust, and note 9 to the listings further confirms this limitation (p. A-34): refinery PM emissions, which are not diesel or gasoline exhaust emissions, are excluded. Section 3.1 of the OEHHA Guidance Manual states that the list of "emitted substances that are addressed in a health risk assessment (HRA) … is contained in … Appendix A of this document."

[50] Attachment 50. Unreferenced charts and tables labeled as summarizing particulate matter emissions during 2007–2014 and GHG emissions during 2008–2014 from Bay Area refineries that CBE received on 20 November 2014 from the Bay Area Air Quality Management District in a meeting attended by G. Karras and R. Lin of CBE and G. Nudd and E. Stevenson of the Air District, among others. Two untitled pages.

[51] Attachment 51. *Excerpts from Bay Area Air Quality Management District Files regarding the Chevron Richmond Refinery Fluid Catalytic Cracking Unit (FCCU, S-4285);* excerpts include: (1) A summary of unit activity and emission changes from 1999–2009; (2) AQMD and Chevron reports on an FCC expansion; (3) Current FCC emission factor data; (4) Annual Source Update FCC data for 1999; and (5) Emission Inventory FCC data for 2009.

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[52] Attachment 52. Karras, May and Lee, 2008. *Increasing GHG Emissions from Dirty Crude, Analysis of publicly available data for one of the oil refining processes expanding for more contaminated oil in California: Hydrogen Steam Reforming;* A CBE Report. Communities for a Better Environment (CBE). 8 December 2008.

[53] Attachment 53. *Historic Refinery GHG Data Comparison: Preliminary Comparison of Estimates for Total CO_2e Emissions from Refining in California;* Compilation of Air Resources Board, Petroleum Industry Information Reporting Act, and Union of Concerned Scientists data. Data compiled by Communities for a Better Environment (CBE) for technical assistance analysis for the work presented in Attachment 16, and this comment. One-page table including data, calculations, references and notes.

Attachment KR-19

Assessment of impact of Rule 12-16 on mortality associated with chronic exposure to $PM_{2.5}$ from heavier oil feedstock processing in Bay Area refineries; appendices from health experts' collaboration report.

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APPENDIX A:

Impact of Rule 12-16 on mortality associated with exposure to PM2.5 from processing heavier oil in Bay Area refineries

Table 1 Potential health impact of 12-16: Averted all-cause deaths attributable to chronic exposures to oil refinery PM2.5 (see Appendix for calculations)

	Regional Population (9 Bay Area Counties)			**Impacted Population*** (<=2.5 miles from refinery)		
	Low	Med	High	Low	Med	High
PARAMETERS						
Risk						
a. Risk of all-cause death for adults (>30 yrs) per $1\mu g/m^3$ PM2.5 increase in long-term exposure	1.008	1.01	1.012	1.008	1.01	1.012
b. Incremental Risk: risk of all-cause death for adults attributable to increment in long-term PM2.5 exposure (risk/ per $1\mu g/m^3$ *PM2.5 increase)*	*0.008*	*0.01*	*0.012*	*0.008*	*0.01*	*0.012*
Exposure						
c. Baseline anthropogenic** exposure ($\mu g/m^3$ $PM_{2.5}$)		5.7			5.1	
d. Proportion of baseline anthropogenic exposure attributable to baseline refinery activity		.05			0.5	
e. Percent change from baseline anthropogenic emissions due to higher emitting oil emissions	40%	70%	100%	40%	70%	100%
f. Conversion factor (change in PM2.5 exposure per change in PM2.5 emissions)		0.5		0.4	0.5	0.6
g. Averted exposure: the annual increased PM2.5 concentration attributed to heavier oil that is averted by Rule 12-16 ($\mu g/m^3$ $PM_{2.5}$)	*0.057*	*0.10*	*0.143*	*0.408*	*0.893*	*1.53*
Population and Mortality						
h. Adult Population (>25)		5,144,345			81,666	
i. Base all-cause adult death rate / person / year		*0.0083403*			*0.0091899*	
IMPACT						
j. Prevented adult all-cause deaths due to 12-16 averting increases in heavier oil PM2.5 emissions***	**20**	**43**	**73**	**2**	**7**	**14**
k. Rate of prevented adult all-cause death due to 12-16 averting increases in heavier oil PM2.5 emissions /100,000 population /yr	**0.38**	**0.83**	**1.43**	**3.00**	**8.21**	**16.88**
l. Cumulative prevented deaths due to 12-16 (40 yrs)	**800**	**1700**	**2900**	**98**	**270**	**550**

* The distance of 2.5 miles was selected to correspond with findings from Brody (2009) and Pastor (2010). Those living < 2.5 miles of refineries (Table 5) can roughly be interpreted as a proxy for impacted, vulnerable, and/or Environmental Justice populations. The Air District's CARE program prioritizes communities and populations most impacted by air pollution, i.e., those with higher air pollution levels and worse health outcomes for diseases affected by air pollutions. Vulnerable populations also include those with heightened vulnerability to PM due to age (<5, elderly), low SES, minority race/ethnic status, and underlying health conditions. This proxy is conservative because *disparate impacts on vulnerable populations may occur beyond 2.5 miles.*

** Anthropogenic exposure is the ambient PM2.5 concentration above background levels (e.g., from sea salt).

*** Annual and cumulative deaths are presented as whole numbers. The resulting rounding error explains any discrepancy between presented deaths and rate.

Notes for Table 1

a. For every 1µg/m3 PM2.5 increase in exposure there is x% increased risk of all-cause mortality, e.g., a 1% increased risk of all-cause death per 1µg/m3 PM2.5 exposure increase. Risk estimates are from BAAQMD's literature review, of for example Pope et. al (2002), Krewsk et. al, (2000), and others. Risk may be underestimated as it does not account for 1) greater energy intensity and toxicity of PM2.5 associated with heavy oil and natural refining, 2) ultrafine PM, and 3) greater vulnerability of impacted populations.

b. Calculated as (all cause death risk in exposed) – (all cause death risk in unexposed), i.e, (risk per increase of 1µg/m^3 PM2.5) – (no increase in exposure) = 1.01 – 1 = .01. For every exposure change of 1µg/m^3 PM2.5 there is a corresponding 1% change in all-cause mortality attributable to PM2.5

c. _Regional_: CAP 2017 p C/7

Impacted Population (<2/5 miles from refinery): From Brody et. al.(2009) baseline PM2.5 exposure was directly measured in Richmond at distances approximately 2.5 miles from the dominant $PM_{2.5}$ source in the refinery. To isolate exposure above background, control site measures in Bolinas were subtracted from Richmond measures, yielding µg/m3 PM2.5. The PM2.5 was chemically fingerprinted to the refinery, finding, for example, high levels, of vanadium and nickel, which in this setting are isolated to refinery emissions (versus traffic). Validating this measure, CARB "ADAM" data for 2013 subtracts annual mean PM2.5 measures at Pt. Reyes from measures at the monitoring station nearest to the refinery, yielding 5.04 µg/m3 PM2.5. A baseline exposure of 4.5 µg/m3 PM2.5 likely underestimates annual exposure because 1) the Brody study was conducted during the summer when PM2.5 concentrations are lowest and 2) Due to wind patterns, and refinery distribution, populations near the other refineries may experience a concentrating of PM2.5. For these reasons, a conservative adjustment was made to factor in higher wintertime concentrations. The annual median concentration was divided by the median concentration Apr–Sep for three years of monitoring at the three closes sites (San Pablo, Vallejo, Concord). The mean of the resulting ratios was multiplied by the Brody measure (2009) such that 4.5 x 1.13 = 5.1 µg/m3 PM2.5 anthropogenic [ ].

d. Portion of the baseline anthropogenic exposure that is attributable to baseline refinery activity
Regional: CAP, 2017 p 2/20
Impacted Population: We set the portion at .5 since Brody et. al. (2009) used chemical fingerprinting to find that heavy oil combustion (refineries being the predominant source in the study area) is the most important contributor, more important than traffic, to elevated anthropogenic PM2.5 concentrations in the study area (<2.5 miles from refinery). We consider this measure reasonable in light of 1) BAAQMD grid modeling that ranged from .2 - .6, 2) an independent assessment of the Districts aerial emissions intensity data (2015) found that, on a mass/$mile^2$ basis, within 2.5 miles of the refineries, the areal source strength is more than twice (0.7) the regional average for all sources (CBE, 2015), and 3) accommodation of some lofting of emissions from hot stacks (2017 Staff Report). These parameters nevertheless likely underestimate, since downwind refinery communities could experience consolidation of PM2.5 from multiple refineries. Further, statewide analyses link high exposure to refinery proximity (<2.5 miles) (Pastor et. al. 2010).

e. Karras (2016) estimated a range of annual tons of PM2.5 emissions that Rule 12-16 would avert, such that, meaning that annually, Rule 12-16 would prevent increases of 364, 728, or 1090 short tons PM2.5 / yr of heavier oil-associated emission, or 40%, 70%, and 100% from current refinery emission rates could be averted through Rule 12-16. Medium Case (0.7) is the midpoint of the 0.4 - 1.0 range

f. The conversion factor translates emissions into exposure. It is derived from the regional weighted average change in PM$_{2.5}$ exposure for a given change in direct emissions of PM$_{2.5}$. Verified by measurements and assuming a 24 hour "backyard exposure," BAAQMD modeled PM2.5 exposure change on a region-wide 4x4km grid relative to a 20% reduction in all-source PM2.5 emissions finding a range from .2 - .6. (CAP, 2017 D/13),
Regional: We applied .5 as the central measure to recognize that the location of population, emission sources, and meteorological conditions coincide. BAAQMD also applied approximately .5 for their regional average conversion. The conversion factor may underestimate impacted population exposures since refineries are strong PM2.5 emission sources near densely populated communities.
Impacted Population: For the <2.5 miles group, given population density and proximity to refineries, which are strong emitters, we used .4 for the lower bound. The upper bound, .6, may underestimate exposure for this group, given monitoring station locations.

g. The increased concentration of PM2.5 (exposure) attributed to heavier oil refining that is averted by Rule 12-16 (μg/m^3 PM$_{2.5}$). Calculated as (baseline total anthropogenic exposure) x (portion of baseline anthropogenic exposure attributable to baseline refinery emissions) x (Portion change from baseline anthropogenic emissions due to higher emitting oil emissions that is averted by 12-16) x (conversion factor). For the Medium regional case: 5.7 μg/m3 PM2.5 x .05 x .7 x .5 = *0.10* μg/m3 PM2.5. The attributable exposure may be underestimated because it does not account for: 1). NOx and SO2 PM-precursor emissions, and 2) the greater concentration of toxics associated with refining of heavy crude feedstock.

h. See Tables 2 and 3

i. Calculated as (annual deaths / total population) / yr. May overestimate or underestimate death rate over time should risk factors systematically improve or worsen.

j. Prevented deaths calculated as Attributable Risk x Attributable Exposure x all-cause per cap death rate x population. For middle regional scenario: .01 x .1 x .00589 x 7,447,686 = 44 deaths prevented by Rule 12-16.

k. Calculated as (deaths prevented / population) x 100,000 population / year.

l. Cumulative Impact calculated as deaths prevented x 40 years, since capital projects to accommodate heavier crude feedstock generally operate for 30 - 50 years. This number underestimates cumulative impact if population increases, as is anticipated.

Table 2. Bay Area communities ≤ 2.5 miles from refineries; local-scale population data [a]

Census	Refinery [b]	Tract distance to fence line (miles)		Fraction [c]	Population	
Tract	≤ 2.5 miles	closest	furthest	≤ 2.5 miles	Total	≤ 2.5 miles
3650.02	Chevron	0.5	2.5	1.00	5,462	5,462
3660.02	Chevron	2.3	3.3	0.20	6,093	1,219
3680.01	Chevron	1.5	2.5	1.00	5,327	5,327
3680.02	Chevron	2.0	2.7	0.71	3,404	2,431
3720	Chevron	1.8	3.1	0.54	7,353	3,959
3740	Chevron	2.0	2.8	0.63	4,506	2,816
3750	Chevron	1.3	1.8	1.00	4,389	4,389
3760	Chevron	0.4	1.5	1.00	5,962	5,962
3770	Chevron	0.4	2.4	1.00	6,962	6,962
3780	Chevron	0.0	3.1	0.81	3,435	2,770
3790	Chevron	1.1	3.1	0.70	6,117	4,282
2506.04	Phillips 66	2.1	3.7	0.25	3,842	961
3560.01	Phillips 66	0.0	3.5	0.71	3,759	2,685
3570	Phillips 66	1.0	5.5	0.33	3,018	1,006
3580	Phillips 66	0.0	2.0	1.00	5,298	5,298
3591.04	Phillips 66	2.0	3.0	0.50	1,932	966
3591.05	Phillips 66	2.0	3.0	0.50	4,542	2,271
3592.03	Phillips 66	1.0	3.3	0.65	6,726	4,387
3923	Phillips 66	1.0	2.0	1.00	3,102	3,102
3150	Shell &/or Tesoro	0.0	7.0	0.36	3,281	1,172
3160	Shell &/or Tesoro	0.5	2.0	1.00	1,483	1,483
3170	Shell &/or Tesoro	0.1	1.0	1.00	2,144	2,144
3180	Shell &/or Tesoro	0.7	4.7	0.45	3,267	1,470
3190	Shell &/or Tesoro	0.2	2.0	1.00	7,412	7,412
3200.01	Shell &/or Tesoro	0.0	2.0	1.00	3,615	3,615
3200.03	Shell &/or Tesoro	0.7	1.6	1.00	2,805	2,805
3200.04	Shell &/or Tesoro	0.2	2.0	1.00	6,216	6,216
3211.01	Shell &/or Tesoro	1.4	2.5	1.00	6,549	6,549
3270	Shell &/or Tesoro	2.0	6.0	0.13	6,695	837
3290	Shell &/or Tesoro	2.0	3.6	0.31	6,309	1,972
2520	Valero	1.8	3.5	0.41	4,157	1,712
2521.02	Valero	0.0	6.0	0.42	3,874	1,614
2521.04	Valero	0.0	4.0	0.63	5,536	3,460
2521.05	Valero	1.7	3.0	0.62	3,256	2,004
2521.06	Valero	0.5	2.0	1.00	4,132	4,132
2521.07	Valero	0.0	1.5	1.00	3,592	3,592
2521.08	Valero	1.0	2.0	1.00	3,165	3,165
		Sum of these tract data:			**168,717**	**121,608**

a) 2010 Census: https://factfinder.census.gov/faces/tableservices/jsf/pages/productview.xhtml?fpt=table

b) Plant or plants within 2.5 miles of part or all of the census tract, identified by current owner/operator.

c)) Estimation of population for tracts partly within a 2.5-mile radius: Tract fraction ≤ 2.5 miles = (2.5 - distance of bisection with radius in miles) ÷ (furthest distance – bisection distance in miles). Results are used to estimate the fraction of the total tract population ≤ 2.5 miles from a refinery. This method's simplifying assumption that population is distributed evenly within each tract despite geography and distance from refineries may result in overestimates or underestimates of local-scale population for those tracts that are partly within 2.5 miles of a refinery.

Table 3. Demographic and Vital Statistics for Bay Area Counties, 2013

						Age Group (years)						
Counties	<1	1-4	5-14	15-24	25-34	35-44	45-54	55-64	65-74	75-84	85+	TOTAL
Alameda												
Deaths	88	10	21	117	160	260	647	1,270	1,604	2,041	3,376	9,597
Population	19,493	76,842	190,900	203,954	232,027	231,327	222,525	191,268	111,600	55,333	28,101	1,563,370
Death Rate*	451.4	13.0	11.0	57.4	69.0	112.4	290.8	664.0	1437.3	3688.6	12013.8	613.9
Contra Costa												
Deaths	50	8	9	77	110	162	439	835	1,235	1,647	2,576	7,148
Population	12,240	49,755	146,153	145,402	129,256	143,616	163,677	140,700	86,747	42,739	21,577	1,081,862
Death Rate	408.5	16.1	6.2	53.0	85.1	112.8	268.2	593.5	1423.7	3853.6	11938.6	660.7
Marin												
Deaths	13	3	3	15	16	32	96	169	269	422	849	1,887
Population	2,334	9,858	30,334	26,078	23,766	32,876	41,089	40,325	28,899	13,245	7,460	256,264
Death Rate	557.0	30.4	9.9	57.5	67.3	97.3	233.6	419.1	930.8	3186.1	11380.7	736.4
Napa												
Deaths	6	1	1	9	10	23	51	125	188	269	511	1,194
Population	1,412	6,196	17,164	19,139	17,225	17,305	19,546	18,767	12,674	6,715	3,688	139,831
Death Rate	424.9	16.1	5.8	47.0	58.1	132.9	260.9	666.1	1483.4	4006.0	13855.7	853.9
San Francisco												
Deaths	30	4	6	40	91	172	351	749	809	1,268	2,134	5,655
Population	9,034	32,463	58,301	78,811	172,506	144,989	112,817	102,892	63,511	38,509	19,994	833,827
Death Rate	332.1	12.3	10.3	50.8	52.8	118.6	311.1	727.9	1273.8	3292.7	10673.2	678.2
San Mateo												
Deaths	19	2	5	35	52	94	257	477	673	1,102	1,920	4,636
Population	9,031	36,415	90,434	83,106	96,589	107,539	110,625	97,585	60,491	32,391	17,651	741,857
Death Rate	210.4	5.5	5.5	42.1	53.8	87.4	232.3	488.8	1112.6	3402.2	10877.6	624.9
Santa Clara												
Deaths	83	12	16	99	117	232	571	1,041	1,388	2,314	3,584	9,457
Population	24,112	95,493	245,789	228,340	264,949	282,446	270,707	211,136	126,347	68,609	32,667	1,850,595
Death Rate	344.2	12.6	6.5	43.4	44.2	82.1	210.9	493.0	1098.6	3372.7	10971.3	511.0
Solano												
Deaths	29	5	7	48	68	93	187	442	520	722	851	2,972
Population	5,127	20,641	55,419	59,872	56,830	53,419	61,449	56,360	32,286	15,914	6,731	424,048
Death Rate	565.6	24.2	12.6	80.2	119.7	174.1	304.3	784.2	1610.6	4536.9	12643.0	700.9
Sonoma												
Deaths	17	5	7	30	47	67	215	519	626	893	1,606	4,032
Population	5,070	21,413	58,627	65,627	64,121	59,350	69,251	71,808	45,050	20,879	11,874	493,070
Death Rate	335.3	23.4	11.9	45.7	73.3	112.9	310.5	722.8	1389.6	4277.0	13525.3	817.7
Bay Area												
Deaths	335	50	75	470	671	1135	2814	5627	7312	10678	17407	46578
Population	87853	349076	893121	910329	1057269	1072867	1071686	930841	567605	294334	149743	7384724
Death Rate	381.3	14.3	8.4	51.6	63.5	105.8	262.6	604.5	1288.2	3627.9	11624.6	630.7
<2.5 miles from refinery**												
Deaths	6	1	1	10	14	21	51	103	142	191	277	817
Population	1,402	5,685	16,278	16,577	15,027	15,911	18,180	15,913	9,612	4,736	2,286	121,608
Death Rate	454.9	18.5	7.9	60.9	95.7	129.4	278.1	648.0	1474.4	4039.0	12106.1	672.0

	Regional			<2.5miles		
	Death	Pop	Rt.	Death	Pop	Rt.
Adults >25 yr***	42905	5,144,345	834.03	751	81,666	918.992

*Death rates are age-specific expressed per 100,000 population. Age-adjusted rates are calculated using the 2000 U.S. Standard Population.

** Deaths in the Impacted Population (<2.5 miles from refinery) were derived using a death rate that divided Contra Costa and Solano Counties' combined deaths by their combined populations and applying this rate to the population living within 2.5 miles of a refinery for one year (from Table 2) (9,521 ÷ 1,518,002) x 121,608 = 763. This estimate may underestimate refinery effects on impacted populations because baseline death rates in communities near refineries may be greater than county-wide average rates. The age specific populations and deaths for the <2.5 miles group were arrived at by multiplying the total population by the age-specific death and population distribution of the combined Contra Costa and Solano Counties .

***The total adult deaths were adjusted to remove suicides and accidents by multiplying the unadjusted total by 6%, which represented the average and most frequent percent of deaths by suicide/accident for each county.

Population ≤ 2.5 miles from refinery fence lines estimated from census tract data. See Table 2

Source: State of California, Department of Public Health, Death Records. State of California, Department of Finance, Race/Ethnic Population with Age and Sex Detail, 2010-2060. Sacramento, CA, December 2014

State of California, Department of Finance, Race/Ethnic Population with Age and Sex Detail, 2010-2060. Sacramento, CA, December 2014.

APPENDIX B

Summary of pollutant – health outcome pairs to inform fuller health assessment of the No-Project Alternative

Table 1 Pollutant–health outcome pairs for which HRAPIE project recommends concentration–response functions (modified from WHO 2013b)

Pollutant metric	Health outcome	Group	RR (95 % CI) per 10 $\mu g/m^3$
$PM_{2.5}$, annual mean	Mortality, all-cause (natural), age 30+ years	A*	1.062 (1.040–1.083)
$PM_{2.5}$, annual mean	Mortality, cerebrovascular disease (includes stroke), ischaemic heart disease, COPD and trachea, bronchus and lung cancer, age 30+ years	A	GBD 2010 study (IHME 2013)[a]
PM_{10}, annual mean	Postneonatal (age 1–12 months) infant mortality, all-cause	B*	1.04 (1.02, 1.07)
PM_{10}, annual mean	Prevalence of bronchitis in children, age 6–12 (or 6–18) years	B*	1.08 (0.98–1.19)
PM_{10}, annual mean	Incidence of chronic bronchitis in adults (age 18+ years)	B*	1.117 (1.040–1.189)
$PM_{2.5}$, daily mean	Mortality, all-cause, all ages	A	1.0123 (1.0045–1.0201)
$PM_{2.5}$, daily mean	Hospital admissions, CVDs (including stroke), all ages	A*	1.0091 (1.0017–1.0166)
$PM_{2.5}$, daily mean	Hospital admissions, respiratory diseases, all ages	A*	1.0190 (0.9982–1.0402)
$PM_{2.5}$, 2-week average, converted to $PM_{2.5}$, annual average	RADs, all ages	B**	1.047 (1.042–1.053)
$PM_{2.5}$, 2-week average, converted to $PM_{2.5}$, annual average	Work days lost, working-age population (age 20–65 years)	B*	1.046 (1.039–1.053)
PM_{10}, daily mean	Incidence of asthma symptoms in asthmatic children aged 5–19 years	B*	1.028 (1.006–1.051)
O_3, summer months (April–September), average of daily maximum 8-h mean over 35 ppb	Mortality, respiratory diseases, age 30+ years	B	1.014 (1.005–1.024)
O_3, daily maximum 8-h mean over 35 ppb	Mortality, all (natural) causes, all ages	A*	1.0029 (1.0014–1.0043)
O_3, daily maximum 8-h mean over 10 ppb	Mortality, all (natural) causes, all ages	A	1.0029 (1.0014–1.0043)
O_3, daily maximum 8-h mean over 35 ppb	Mortality, CVDs and respiratory diseases, all ages	A	CVD: 1.0049 (1.0013–1.0085); respiratory: 1.0029 (0.9989–1.0070)
O_3, daily maximum 8-h mean over 10 ppb	Mortality, CVDs and respiratory diseases, all ages	A	CVD: 1.0049 (1.0013–1.0085); respiratory: 1.0029 (0.9989–1.0070)
O_3, daily maximum 8-h mean over 35 ppb	Hospital admissions, CVDs (excluding stroke) and respiratory diseases, age 65+ years	A*	CVD: 1.0089 (1.0050–1.0127); respiratory: 1.0044 (1.0007–1.0083)
O_3, daily maximum 8-h mean over 10 ppb	Hospital admissions, CVDs (excluding stroke) and respiratory diseases, age 65+ years	A	CVD: 1.0089 (1.0050–1.0127); respiratory: 1.0044 (1.0007–1.0083)
O_3, daily maximum 8-h mean over 35 ppb	MRADs, all ages	B*	1.0154 (1.0060–1.0249)
O_3, daily maximum 8-h mean over 10 ppb	MRADs, all ages	B	1.0154 (1.0060–1.0249)
NO_2, annual mean over 20 $\mu g/m^3$	Mortality, all (natural) causes, age 30+ years	B*	1.055 (1.031–1.080)
NO_2, annual mean	Prevalence of bronchitic symptoms in asthmatic children aged 5–14 years	B*	1.021 (0.990–1.060) per 1 $\mu g/m^3$ change in annual mean NO_2
NO_2, daily maximum 1-h mean	Mortality, all (natural) causes, all ages	A*	1.0027 (1.0016–1.0038)
NO_2, daily maximum 1-h mean	Hospital admissions, respiratory diseases, all ages	A	1.0015 (0.9992–1.0038)

APPENDIX C:

Partial listing of evidence establishing association between residential proximity to refineries and adverse health outcomes

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Appendix D. Data and results for determing annual/summer exposure ratios: 24-hour $PM_{2.5}$ from the three nearest NAAQS stations to Bay Area oil refineries, 2013–2015.
Data: California Air Resources Board: http://www.arb.ca.gov/adam/weekly/weeklydisplay.php

ratios mean: 1.132	3-y Annual (median)	3-y Apr–Sep (median)
San Pablo	9.50	8.80
Vallejo	8.40	7.15
Concord	6.40	5.60

blank cell = insufficient data to determine

Station	Year	Month	Day	$PM_{2.5}$ ug/m^3 24 hr avg.
Concord-2975 Treat Blvd.	2013	1	1	12.0
Concord-2975 Treat Blvd.	2013	1	2	7.4
Concord-2975 Treat Blvd.	2013	1	3	17.7
Concord-2975 Treat Blvd.	2013	1	4	13.8
Concord-2975 Treat Blvd.	2013	1	5	27.6
Concord-2975 Treat Blvd.	2013	1	6	11.0
Concord-2975 Treat Blvd.	2013	1	7	9.5
Concord-2975 Treat Blvd.	2013	1	8	21.0
Concord-2975 Treat Blvd.	2013	1	9	13.2
Concord-2975 Treat Blvd.	2013	1	10	2.5
Concord-2975 Treat Blvd.	2013	1	11	4.2
Concord-2975 Treat Blvd.	2013	1	12	8.7
Concord-2975 Treat Blvd.	2013	1	13	14.2
Concord-2975 Treat Blvd.	2013	1	14	4.6
Concord-2975 Treat Blvd.	2013	1	15	12.7
Concord-2975 Treat Blvd.	2013	1	16	21.5
Concord-2975 Treat Blvd.	2013	1	17	12.3
Concord-2975 Treat Blvd.	2013	1	18	8.9
Concord-2975 Treat Blvd.	2013	1	19	8.6
Concord-2975 Treat Blvd.	2013	1	20	9.9
Concord-2975 Treat Blvd.	2013	1	21	14.2
Concord-2975 Treat Blvd.	2013	1	22	24.3
Concord-2975 Treat Blvd.	2013	1	23	36.2
Concord-2975 Treat Blvd.	2013	1	24	11.0
Concord-2975 Treat Blvd.	2013	1	25	12.0
Concord-2975 Treat Blvd.	2013	1	26	4.1
Concord-2975 Treat Blvd.	2013	1	27	2.5
Concord-2975 Treat Blvd.	2013	1	28	2.3
Concord-2975 Treat Blvd.	2013	1	29	3.9
Concord-2975 Treat Blvd.	2013	1	30	5.8
Concord-2975 Treat Blvd.	2013	1	31	15.7
Concord-2975 Treat Blvd.	2013	2	1	13.3
Concord-2975 Treat Blvd.	2013	2	2	12.1
Concord-2975 Treat Blvd.	2013	2	3	9.4
Concord-2975 Treat Blvd.	2013	2	4	13.2
Concord-2975 Treat Blvd.	2013	2	5	5.3
Concord-2975 Treat Blvd.	2013	2	6	4.1
Concord-2975 Treat Blvd.	2013	2	7	3.6
Concord-2975 Treat Blvd.	2013	2	8	3.2
Concord-2975 Treat Blvd.	2013	2	9	4.0
Concord-2975 Treat Blvd.	2013	2	10	7.5
Concord-2975 Treat Blvd.	2013	2	11	5.4
Concord-2975 Treat Blvd.	2013	2	12	13.4
Concord-2975 Treat Blvd.	2013	2	13	9.6
Concord-2975 Treat Blvd.	2013	2	14	6.3
Concord-2975 Treat Blvd.	2013	2	15	8.4
Concord-2975 Treat Blvd.	2013	2	16	14.8
Concord-2975 Treat Blvd.	2013	2	17	6.4
Concord-2975 Treat Blvd.	2013	2	18	3.9
Concord-2975 Treat Blvd.	2013	2	19	2.9

Concord-2975 Treat Blvd.	2013	2	20	4.1
Concord-2975 Treat Blvd.	2013	2	21	3.4
Concord-2975 Treat Blvd.	2013	2	22	5.3
Concord-2975 Treat Blvd.	2013	2	23	4.3
Concord-2975 Treat Blvd.	2013	2	24	2.5
Concord-2975 Treat Blvd.	2013	2	25	5.3
Concord-2975 Treat Blvd.	2013	2	26	4.6
Concord-2975 Treat Blvd.	2013	2	27	5.3
Concord-2975 Treat Blvd.	2013	2	28	1.9
Concord-2975 Treat Blvd.	2013	3	1	3.0
Concord-2975 Treat Blvd.	2013	3	2	8.9
Concord-2975 Treat Blvd.	2013	3	3	6.8
Concord-2975 Treat Blvd.	2013	3	4	6.0
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Concord-2975 Treat Blvd.	2013	3	9	3.5
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Concord-2975 Treat Blvd.	2014	10	20	4.5
Concord-2975 Treat Blvd.	2014	10	21	4.7
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Concord-2975 Treat Blvd.	2015	11	12	7.5
Concord-2975 Treat Blvd.	2015	11	13	10.8
Concord-2975 Treat Blvd.	2015	11	14	16.8
Concord-2975 Treat Blvd.	2015	11	15	3.9
Concord-2975 Treat Blvd.	2015	11	16	3.7
Concord-2975 Treat Blvd.	2015	11	17	3.7
Concord-2975 Treat Blvd.	2015	11	18	4.1
Concord-2975 Treat Blvd.	2015	11	19	6.1

Concord-2975 Treat Blvd.	2015	11	20	5.9
Concord-2975 Treat Blvd.	2015	11	21	15.7
Concord-2975 Treat Blvd.	2015	11	22	16.4
Concord-2975 Treat Blvd.	2015	11	23	16.3
Concord-2975 Treat Blvd.	2015	11	24	4.0
Concord-2975 Treat Blvd.	2015	11	25	4.7
Concord-2975 Treat Blvd.	2015	11	26	8.2
Concord-2975 Treat Blvd.	2015	11	27	8.1
Concord-2975 Treat Blvd.	2015	11	28	8.2
Concord-2975 Treat Blvd.	2015	11	29	10.2
Concord-2975 Treat Blvd.	2015	11	30	13.1
Concord-2975 Treat Blvd.	2015	12	1	8.3
Concord-2975 Treat Blvd.	2015	12	2	17.9
Concord-2975 Treat Blvd.	2015	12	3	13.1
Concord-2975 Treat Blvd.	2015	12	4	5.9
Concord-2975 Treat Blvd.	2015	12	5	14.3
Concord-2975 Treat Blvd.	2015	12	6	10.7
Concord-2975 Treat Blvd.	2015	12	7	14.6
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Concord-2975 Treat Blvd.	2015	12	10	
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Concord-2975 Treat Blvd.	2015	12	12	
Concord-2975 Treat Blvd.	2015	12	13	
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Concord-2975 Treat Blvd.	2015	12	18	7.0
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Concord-2975 Treat Blvd.	2015	12	22	3.8
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Concord-2975 Treat Blvd.	2015	12	28	9.0
Concord-2975 Treat Blvd.	2015	12	29	6.7
Concord-2975 Treat Blvd.	2015	12	30	12.9
Concord-2975 Treat Blvd.	2015	12	31	13.5
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San Pablo-Rumrill	2013	1	2	7.6
San Pablo-Rumrill	2013	1	3	17.4
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San Pablo-Rumrill	2013	1	8	17.6
San Pablo-Rumrill	2013	1	9	15.4
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San Pablo-Rumrill	2013	1	12	7.9
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San Pablo-Rumrill	2013	11	4	9.5
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San Pablo-Rumrill	2013	12	31	30.4
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San Pablo-Rumrill	2014	1	2	25.0
San Pablo-Rumrill	2014	1	3	21.0
San Pablo-Rumrill	2014	1	4	16.4
San Pablo-Rumrill	2014	1	5	12.8
San Pablo-Rumrill	2014	1	6	26.5

San Pablo-Rumrill	2014	1	7	23.4
San Pablo-Rumrill	2014	1	8	10.2
San Pablo-Rumrill	2014	1	9	13.5
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San Pablo-Rumrill	2014	1	11	13.4
San Pablo-Rumrill	2014	1	12	12.1
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San Pablo-Rumrill	2014	1	15	17.2
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San Pablo-Rumrill	2014	1	18	18.8
San Pablo-Rumrill	2014	1	19	25.7
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San Pablo-Rumrill	2014	1	22	17.8
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San Pablo-Rumrill	2014	1	29	9.0
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San Pablo-Rumrill	2014	1	31	11.9
San Pablo-Rumrill	2014	2	1	11.3
San Pablo-Rumrill	2014	2	2	10.8
San Pablo-Rumrill	2014	2	3	11.5
San Pablo-Rumrill	2014	2	4	10.3
San Pablo-Rumrill	2014	2	5	10.2
San Pablo-Rumrill	2014	2	6	15.7
San Pablo-Rumrill	2014	2	7	11.7
San Pablo-Rumrill	2014	2	8	7.2
San Pablo-Rumrill	2014	2	9	9.3
San Pablo-Rumrill	2014	2	10	9.0
San Pablo-Rumrill	2014	2	11	13.6
San Pablo-Rumrill	2014	2	12	14.1
San Pablo-Rumrill	2014	2	13	12.7
San Pablo-Rumrill	2014	2	14	8.8
San Pablo-Rumrill	2014	2	15	11.0
San Pablo-Rumrill	2014	2	16	10.5
San Pablo-Rumrill	2014	2	17	10.4
San Pablo-Rumrill	2014	2	18	11.5
San Pablo-Rumrill	2014	2	19	10.5
San Pablo-Rumrill	2014	2	20	10.3
San Pablo-Rumrill	2014	2	21	12.5
San Pablo-Rumrill	2014	2	22	14.7
San Pablo-Rumrill	2014	2	23	12.6
San Pablo-Rumrill	2014	2	24	13.2
San Pablo-Rumrill	2014	2	25	15.0
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San Pablo-Rumrill	2014	2	27	11.7
San Pablo-Rumrill	2014	2	28	9.5
San Pablo-Rumrill	2014	3	1	11.0
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San Pablo-Rumrill	2014	3	3	14.4
San Pablo-Rumrill	2014	3	4	11.3
San Pablo-Rumrill	2014	3	5	13.2
San Pablo-Rumrill	2014	3	6	14.0

San Pablo-Rumrill	2014	3	7	12.4
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San Pablo-Rumrill	2014	3	9	14.3
San Pablo-Rumrill	2014	3	10	9.4
San Pablo-Rumrill	2014	3	11	8.4
San Pablo-Rumrill	2014	3	12	8.6
San Pablo-Rumrill	2014	3	13	12.2
San Pablo-Rumrill	2014	3	14	15.8
San Pablo-Rumrill	2014	3	15	12.9
San Pablo-Rumrill	2014	3	16	13.0
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San Pablo-Rumrill	2014	3	18	9.9
San Pablo-Rumrill	2014	3	19	11.0
San Pablo-Rumrill	2014	3	20	
San Pablo-Rumrill	2014	3	21	
San Pablo-Rumrill	2014	3	22	
San Pablo-Rumrill	2014	3	23	
San Pablo-Rumrill	2014	3	24	
San Pablo-Rumrill	2014	3	25	10.4
San Pablo-Rumrill	2014	3	26	9.8
San Pablo-Rumrill	2014	3	27	12.7
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San Pablo-Rumrill	2014	3	31	9.7
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San Pablo-Rumrill	2014	4	2	6.6
San Pablo-Rumrill	2014	4	3	8.5
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San Pablo-Rumrill	2014	4	11	13.0
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San Pablo-Rumrill	2014	4	13	15.6
San Pablo-Rumrill	2014	4	14	14.7
San Pablo-Rumrill	2014	4	15	17.7
San Pablo-Rumrill	2014	4	16	19.3
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San Pablo-Rumrill	2014	5	3	6.4
San Pablo-Rumrill	2014	5	4	6.3

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San Pablo-Rumrill	2014	5	9	6.4
San Pablo-Rumrill	2014	5	10	6.9
San Pablo-Rumrill	2014	5	11	6.4
San Pablo-Rumrill	2014	5	12	11.5
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San Pablo-Rumrill	2014	5	14	12.2
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San Pablo-Rumrill	2014	5	29	14.2
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San Pablo-Rumrill	2014	6	4	12.8
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San Pablo-Rumrill	2014	6	11	9.5
San Pablo-Rumrill	2014	6	12	9.0
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San Pablo-Rumrill	2014	6	28	7.3
San Pablo-Rumrill	2014	6	29	13.2
San Pablo-Rumrill	2014	6	30	18.5
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San Pablo-Rumrill	2014	7	2	9.1

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San Pablo-Rumrill	2014	7	5	8.4
San Pablo-Rumrill	2014	7	6	7.2
San Pablo-Rumrill	2014	7	7	5.8
San Pablo-Rumrill	2014	7	8	4.3
San Pablo-Rumrill	2014	7	9	4.5
San Pablo-Rumrill	2014	7	10	5.0
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San Pablo-Rumrill	2014	7	19	5.5
San Pablo-Rumrill	2014	7	20	4.2
San Pablo-Rumrill	2014	7	21	3.8
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San Pablo-Rumrill	2014	7	29	6.0
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San Pablo-Rumrill	2014	8	2	8.8
San Pablo-Rumrill	2014	8	3	8.7
San Pablo-Rumrill	2014	8	4	6.0
San Pablo-Rumrill	2014	8	5	7.4
San Pablo-Rumrill	2014	8	6	7.4
San Pablo-Rumrill	2014	8	7	10.4
San Pablo-Rumrill	2014	8	8	17.1
San Pablo-Rumrill	2014	8	9	13.1
San Pablo-Rumrill	2014	8	10	8.1
San Pablo-Rumrill	2014	8	11	8.2
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San Pablo-Rumrill	2014	9	2	8.2
San Pablo-Rumrill	2014	9	3	11.7
San Pablo-Rumrill	2014	9	4	13.8
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San Pablo-Rumrill	2014	9	6	23.2
San Pablo-Rumrill	2014	9	7	15.9
San Pablo-Rumrill	2014	9	8	14.3
San Pablo-Rumrill	2014	9	9	10.0
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San Pablo-Rumrill	2014	9	11	13.2
San Pablo-Rumrill	2014	9	12	11.5
San Pablo-Rumrill	2014	9	13	10.3
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San Pablo-Rumrill	2014	9	23	6.1
San Pablo-Rumrill	2014	9	24	5.4
San Pablo-Rumrill	2014	9	25	7.6
San Pablo-Rumrill	2014	9	26	
San Pablo-Rumrill	2014	9	27	
San Pablo-Rumrill	2014	9	28	
San Pablo-Rumrill	2014	9	29	
San Pablo-Rumrill	2014	9	30	7.1
San Pablo-Rumrill	2014	10	1	5.9
San Pablo-Rumrill	2014	10	2	6.2
San Pablo-Rumrill	2014	10	3	8.4
San Pablo-Rumrill	2014	10	4	7.9
San Pablo-Rumrill	2014	10	5	6.9
San Pablo-Rumrill	2014	10	6	7.0
San Pablo-Rumrill	2014	10	7	5.8
San Pablo-Rumrill	2014	10	8	8.0
San Pablo-Rumrill	2014	10	9	4.5
San Pablo-Rumrill	2014	10	10	6.6
San Pablo-Rumrill	2014	10	11	6.0
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San Pablo-Rumrill	2014	10	13	7.4
San Pablo-Rumrill	2014	10	14	8.7
San Pablo-Rumrill	2014	10	15	4.7
San Pablo-Rumrill	2014	10	16	4.3
San Pablo-Rumrill	2014	10	17	3.4
San Pablo-Rumrill	2014	10	18	5.0
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San Pablo-Rumrill	2014	10	20	4.0
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San Pablo-Rumrill	2014	10	22	7.6
San Pablo-Rumrill	2014	10	23	5.0
San Pablo-Rumrill	2014	10	24	6.5
San Pablo-Rumrill	2014	10	25	4.5
San Pablo-Rumrill	2014	10	26	5.8
San Pablo-Rumrill	2014	10	27	5.0
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San Pablo-Rumrill	2014	10	29	7.1
San Pablo-Rumrill	2014	10	30	5.1
San Pablo-Rumrill	2014	10	31	
San Pablo-Rumrill	2014	11	1	4.2
San Pablo-Rumrill	2014	11	2	5.0
San Pablo-Rumrill	2014	11	3	6.5
San Pablo-Rumrill	2014	11	4	7.1
San Pablo-Rumrill	2014	11	5	9.5
San Pablo-Rumrill	2014	11	6	14.7
San Pablo-Rumrill	2014	11	7	8.5
San Pablo-Rumrill	2014	11	8	10.4
San Pablo-Rumrill	2014	11	9	7.9
San Pablo-Rumrill	2014	11	10	11.7
San Pablo-Rumrill	2014	11	11	6.8
San Pablo-Rumrill	2014	11	12	8.2
San Pablo-Rumrill	2014	11	13	5.3
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San Pablo-Rumrill	2014	11	15	7.7
San Pablo-Rumrill	2014	11	16	7.2
San Pablo-Rumrill	2014	11	17	7.8
San Pablo-Rumrill	2014	11	18	16.4
San Pablo-Rumrill	2014	11	19	12.7
San Pablo-Rumrill	2014	11	20	11.6
San Pablo-Rumrill	2014	11	21	13.7
San Pablo-Rumrill	2014	11	22	3.5
San Pablo-Rumrill	2014	11	23	5.8
San Pablo-Rumrill	2014	11	24	9.5
San Pablo-Rumrill	2014	11	25	16.1
San Pablo-Rumrill	2014	11	26	18.9
San Pablo-Rumrill	2014	11	27	28.2
San Pablo-Rumrill	2014	11	28	13.0
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San Pablo-Rumrill	2014	12	1	11.8
San Pablo-Rumrill	2014	12	2	3.6
San Pablo-Rumrill	2014	12	3	3.4
San Pablo-Rumrill	2014	12	4	6.3
San Pablo-Rumrill	2014	12	5	4.1
San Pablo-Rumrill	2014	12	6	7.4
San Pablo-Rumrill	2014	12	7	9.7
San Pablo-Rumrill	2014	12	8	13.6
San Pablo-Rumrill	2014	12	9	19.0
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San Pablo-Rumrill	2014	12	11	4.1
San Pablo-Rumrill	2014	12	12	7.1
San Pablo-Rumrill	2014	12	13	10.5
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San Pablo-Rumrill	2014	12	15	5.6
San Pablo-Rumrill	2014	12	16	4.1
San Pablo-Rumrill	2014	12	17	6.7
San Pablo-Rumrill	2014	12	18	9.8
San Pablo-Rumrill	2014	12	19	6.0
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San Pablo-Rumrill	2014	12	21	4.8
San Pablo-Rumrill	2014	12	22	6.3
San Pablo-Rumrill	2014	12	23	4.9
San Pablo-Rumrill	2014	12	24	6.0
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San Pablo-Rumrill	2014	12	26	5.8

San Pablo-Rumrill	2014	12	27	11.4
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San Pablo-Rumrill	2014	12	29	7.9
San Pablo-Rumrill	2014	12	30	5.6
San Pablo-Rumrill	2014	12	31	8.5
San Pablo-Rumrill	2015	1	1	17.2
San Pablo-Rumrill	2015	1	2	22.7
San Pablo-Rumrill	2015	1	3	29.6
San Pablo-Rumrill	2015	1	4	32.1
San Pablo-Rumrill	2015	1	5	26.4
San Pablo-Rumrill	2015	1	6	26.5
San Pablo-Rumrill	2015	1	7	16.8
San Pablo-Rumrill	2015	1	8	31.8
San Pablo-Rumrill	2015	1	9	24.9
San Pablo-Rumrill	2015	1	10	16.1
San Pablo-Rumrill	2015	1	11	17.4
San Pablo-Rumrill	2015	1	12	8.4
San Pablo-Rumrill	2015	1	13	7.5
San Pablo-Rumrill	2015	1	14	31.7
San Pablo-Rumrill	2015	1	15	33.2
San Pablo-Rumrill	2015	1	16	31.6
San Pablo-Rumrill	2015	1	17	18.6
San Pablo-Rumrill	2015	1	18	13.6
San Pablo-Rumrill	2015	1	19	11.3
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San Pablo-Rumrill	2015	1	21	13.3
San Pablo-Rumrill	2015	1	22	22.2
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San Pablo-Rumrill	2015	1	24	20.4
San Pablo-Rumrill	2015	1	25	17.8
San Pablo-Rumrill	2015	1	26	17.9
San Pablo-Rumrill	2015	1	27	10.9
San Pablo-Rumrill	2015	1	28	16.0
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San Pablo-Rumrill	2015	1	30	12.6
San Pablo-Rumrill	2015	1	31	5.1
San Pablo-Rumrill	2015	2	1	17.2
San Pablo-Rumrill	2015	2	2	23.5
San Pablo-Rumrill	2015	2	3	14.4
San Pablo-Rumrill	2015	2	4	26.2
San Pablo-Rumrill	2015	2	5	8.0
San Pablo-Rumrill	2015	2	6	2.4
San Pablo-Rumrill	2015	2	7	6.5
San Pablo-Rumrill	2015	2	8	3.9
San Pablo-Rumrill	2015	2	9	8.1
San Pablo-Rumrill	2015	2	10	4.5
San Pablo-Rumrill	2015	2	11	6.0
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San Pablo-Rumrill	2015	2	13	7.9
San Pablo-Rumrill	2015	2	14	7.9
San Pablo-Rumrill	2015	2	15	6.4
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San Pablo-Rumrill	2015	2	18	8.6
San Pablo-Rumrill	2015	2	19	13.7
San Pablo-Rumrill	2015	2	20	8.9
San Pablo-Rumrill	2015	2	21	9.9
San Pablo-Rumrill	2015	2	22	6.3
San Pablo-Rumrill	2015	2	23	5.2

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San Pablo-Rumrill	2015	2	27	2.5
San Pablo-Rumrill	2015	2	28	6.1
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San Pablo-Rumrill	2015	3	15	4.8
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San Pablo-Rumrill	2015	3	18	9.3
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San Pablo-Rumrill	2015	3	22	4.0
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San Pablo-Rumrill	2015	3	24	3.0
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San Pablo-Rumrill	2015	3	27	7.4
San Pablo-Rumrill	2015	3	28	10.4
San Pablo-Rumrill	2015	3	29	10.6
San Pablo-Rumrill	2015	3	30	4.8
San Pablo-Rumrill	2015	3	31	
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San Pablo-Rumrill	2015	4	2	5.8
San Pablo-Rumrill	2015	4	3	12.0
San Pablo-Rumrill	2015	4	4	7.4
San Pablo-Rumrill	2015	4	5	5.0
San Pablo-Rumrill	2015	4	6	5.6
San Pablo-Rumrill	2015	4	7	1.9
San Pablo-Rumrill	2015	4	8	2.9
San Pablo-Rumrill	2015	4	9	2.0
San Pablo-Rumrill	2015	4	10	2.5
San Pablo-Rumrill	2015	4	11	8.1
San Pablo-Rumrill	2015	4	12	2.7
San Pablo-Rumrill	2015	4	13	4.7
San Pablo-Rumrill	2015	4	14	3.6
San Pablo-Rumrill	2015	4	15	4.4
San Pablo-Rumrill	2015	4	16	4.4
San Pablo-Rumrill	2015	4	17	7.6
San Pablo-Rumrill	2015	4	18	8.3
San Pablo-Rumrill	2015	4	19	5.0
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San Pablo-Rumrill	2015	4	21	4.7
San Pablo-Rumrill	2015	4	22	10.0
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San Pablo-Rumrill	2015	4	24	4.2
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San Pablo-Rumrill	2015	4	26	3.2
San Pablo-Rumrill	2015	4	27	3.8
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San Pablo-Rumrill	2015	4	30	11.5
San Pablo-Rumrill	2015	5	1	10.4
San Pablo-Rumrill	2015	5	2	9.4
San Pablo-Rumrill	2015	5	3	6.0
San Pablo-Rumrill	2015	5	4	6.5
San Pablo-Rumrill	2015	5	5	9.2
San Pablo-Rumrill	2015	5	6	11.5
San Pablo-Rumrill	2015	5	7	12.0
San Pablo-Rumrill	2015	5	8	12.2
San Pablo-Rumrill	2015	5	9	6.2
San Pablo-Rumrill	2015	5	10	7.7
San Pablo-Rumrill	2015	5	11	5.0
San Pablo-Rumrill	2015	5	12	2.5
San Pablo-Rumrill	2015	5	13	1.5
San Pablo-Rumrill	2015	5	14	0.8
San Pablo-Rumrill	2015	5	15	1.1
San Pablo-Rumrill	2015	5	16	1.7
San Pablo-Rumrill	2015	5	17	1.0
San Pablo-Rumrill	2015	5	18	1.3
San Pablo-Rumrill	2015	5	19	1.7
San Pablo-Rumrill	2015	5	20	1.1
San Pablo-Rumrill	2015	5	21	0.5
San Pablo-Rumrill	2015	5	22	1.3
San Pablo-Rumrill	2015	5	23	4.0
San Pablo-Rumrill	2015	5	24	4.1
San Pablo-Rumrill	2015	5	25	0.5
San Pablo-Rumrill	2015	5	26	0.6
San Pablo-Rumrill	2015	5	27	0.8
San Pablo-Rumrill	2015	5	28	
San Pablo-Rumrill	2015	5	29	
San Pablo-Rumrill	2015	5	30	
San Pablo-Rumrill	2015	5	31	
San Pablo-Rumrill	2015	6	1	
San Pablo-Rumrill	2015	6	2	
San Pablo-Rumrill	2015	6	3	
San Pablo-Rumrill	2015	6	4	
San Pablo-Rumrill	2015	6	5	
San Pablo-Rumrill	2015	6	6	
San Pablo-Rumrill	2015	6	7	
San Pablo-Rumrill	2015	6	8	
San Pablo-Rumrill	2015	6	9	4.5
San Pablo-Rumrill	2015	6	10	7.3
San Pablo-Rumrill	2015	6	11	12.3
San Pablo-Rumrill	2015	6	12	12.1
San Pablo-Rumrill	2015	6	13	17.0
San Pablo-Rumrill	2015	6	14	18.0
San Pablo-Rumrill	2015	6	15	14.3
San Pablo-Rumrill	2015	6	16	16.0
San Pablo-Rumrill	2015	6	17	14.7
San Pablo-Rumrill	2015	6	18	11.7
San Pablo-Rumrill	2015	6	19	9.4
San Pablo-Rumrill	2015	6	20	9.4
San Pablo-Rumrill	2015	6	21	9.7

San Pablo-Rumrill	2015	6	22	8.3
San Pablo-Rumrill	2015	6	23	12.5
San Pablo-Rumrill	2015	6	24	11.5
San Pablo-Rumrill	2015	6	25	12.0
San Pablo-Rumrill	2015	6	26	9.6
San Pablo-Rumrill	2015	6	27	4.9
San Pablo-Rumrill	2015	6	28	3.2
San Pablo-Rumrill	2015	6	29	4.6
San Pablo-Rumrill	2015	6	30	6.2
San Pablo-Rumrill	2015	7	1	6.5
San Pablo-Rumrill	2015	7	2	5.5
San Pablo-Rumrill	2015	7	3	4.4
San Pablo-Rumrill	2015	7	4	3.1
San Pablo-Rumrill	2015	7	5	3.2
San Pablo-Rumrill	2015	7	6	7.0
San Pablo-Rumrill	2015	7	7	6.2
San Pablo-Rumrill	2015	7	8	4.1
San Pablo-Rumrill	2015	7	9	6.7
San Pablo-Rumrill	2015	7	10	6.8
San Pablo-Rumrill	2015	7	11	4.3
San Pablo-Rumrill	2015	7	12	4.6
San Pablo-Rumrill	2015	7	13	5.1
San Pablo-Rumrill	2015	7	14	6.9
San Pablo-Rumrill	2015	7	15	10.4
San Pablo-Rumrill	2015	7	16	4.4
San Pablo-Rumrill	2015	7	17	8.7
San Pablo-Rumrill	2015	7	18	7.2
San Pablo-Rumrill	2015	7	19	6.7
San Pablo-Rumrill	2015	7	20	9.1
San Pablo-Rumrill	2015	7	21	8.0
San Pablo-Rumrill	2015	7	22	11.6
San Pablo-Rumrill	2015	7	23	10.4
San Pablo-Rumrill	2015	7	24	7.4
San Pablo-Rumrill	2015	7	25	6.2
San Pablo-Rumrill	2015	7	26	9.8
San Pablo-Rumrill	2015	7	27	12.8
San Pablo-Rumrill	2015	7	28	
San Pablo-Rumrill	2015	7	29	8.3
San Pablo-Rumrill	2015	7	30	9.6
San Pablo-Rumrill	2015	7	31	8.5
San Pablo-Rumrill	2015	8	1	10.0
San Pablo-Rumrill	2015	8	2	9.4
San Pablo-Rumrill	2015	8	3	7.2
San Pablo-Rumrill	2015	8	4	8.0
San Pablo-Rumrill	2015	8	5	7.8
San Pablo-Rumrill	2015	8	6	13.1
San Pablo-Rumrill	2015	8	7	13.2
San Pablo-Rumrill	2015	8	8	9.2
San Pablo-Rumrill	2015	8	9	5.0
San Pablo-Rumrill	2015	8	10	4.4
San Pablo-Rumrill	2015	8	11	4.9
San Pablo-Rumrill	2015	8	12	4.3
San Pablo-Rumrill	2015	8	13	4.3
San Pablo-Rumrill	2015	8	14	6.1
San Pablo-Rumrill	2015	8	15	22.6
San Pablo-Rumrill	2015	8	16	30.8
San Pablo-Rumrill	2015	8	17	25.1
San Pablo-Rumrill	2015	8	18	21.7
San Pablo-Rumrill	2015	8	19	13.2

San Pablo-Rumrill	2015	8	20	11.6
San Pablo-Rumrill	2015	8	21	10.6
San Pablo-Rumrill	2015	8	22	10.5
San Pablo-Rumrill	2015	8	23	11.7
San Pablo-Rumrill	2015	8	24	15.2
San Pablo-Rumrill	2015	8	25	16.0
San Pablo-Rumrill	2015	8	26	13.5
San Pablo-Rumrill	2015	8	27	10.0
San Pablo-Rumrill	2015	8	28	7.3
San Pablo-Rumrill	2015	8	29	5.2
San Pablo-Rumrill	2015	8	30	5.6
San Pablo-Rumrill	2015	8	31	11.8
San Pablo-Rumrill	2015	9	1	12.2
San Pablo-Rumrill	2015	9	2	6.7
San Pablo-Rumrill	2015	9	3	8.5
San Pablo-Rumrill	2015	9	4	8.2
San Pablo-Rumrill	2015	9	5	5.5
San Pablo-Rumrill	2015	9	6	7.4
San Pablo-Rumrill	2015	9	7	7.6
San Pablo-Rumrill	2015	9	8	9.6
San Pablo-Rumrill	2015	9	9	9.7
San Pablo-Rumrill	2015	9	10	7.0
San Pablo-Rumrill	2015	9	11	6.4
San Pablo-Rumrill	2015	9	12	6.8
San Pablo-Rumrill	2015	9	13	6.3
San Pablo-Rumrill	2015	9	14	8.3
San Pablo-Rumrill	2015	9	15	
San Pablo-Rumrill	2015	9	16	5.2
San Pablo-Rumrill	2015	9	17	6.5
San Pablo-Rumrill	2015	9	18	
San Pablo-Rumrill	2015	9	19	
San Pablo-Rumrill	2015	9	20	
San Pablo-Rumrill	2015	9	21	
San Pablo-Rumrill	2015	9	22	12.6
San Pablo-Rumrill	2015	9	23	10.0
San Pablo-Rumrill	2015	9	24	7.8
San Pablo-Rumrill	2015	9	25	8.3
San Pablo-Rumrill	2015	9	26	6.8
San Pablo-Rumrill	2015	9	27	12.5
San Pablo-Rumrill	2015	9	28	9.7
San Pablo-Rumrill	2015	9	29	8.9
San Pablo-Rumrill	2015	9	30	9.0
San Pablo-Rumrill	2015	10	1	6.1
San Pablo-Rumrill	2015	10	2	8.7
San Pablo-Rumrill	2015	10	3	14.5
San Pablo-Rumrill	2015	10	4	12.4
San Pablo-Rumrill	2015	10	5	11.1
San Pablo-Rumrill	2015	10	6	10.2
San Pablo-Rumrill	2015	10	7	12.2
San Pablo-Rumrill	2015	10	8	11.5
San Pablo-Rumrill	2015	10	9	8.2
San Pablo-Rumrill	2015	10	10	5.2
San Pablo-Rumrill	2015	10	11	7.6
San Pablo-Rumrill	2015	10	12	9.6
San Pablo-Rumrill	2015	10	13	12.2
San Pablo-Rumrill	2015	10	14	7.7
San Pablo-Rumrill	2015	10	15	9.0
San Pablo-Rumrill	2015	10	16	6.3
San Pablo-Rumrill	2015	10	17	4.5

San Pablo-Rumrill	2015	10	18	3.3
San Pablo-Rumrill	2015	10	19	5.8
San Pablo-Rumrill	2015	10	20	4.2
San Pablo-Rumrill	2015	10	21	7.7
San Pablo-Rumrill	2015	10	22	12.2
San Pablo-Rumrill	2015	10	23	12.2
San Pablo-Rumrill	2015	10	24	11.6
San Pablo-Rumrill	2015	10	25	7.5
San Pablo-Rumrill	2015	10	26	6.3
San Pablo-Rumrill	2015	10	27	6.3
San Pablo-Rumrill	2015	10	28	5.2
San Pablo-Rumrill	2015	10	29	4.6
San Pablo-Rumrill	2015	10	30	7.2
San Pablo-Rumrill	2015	10	31	7.4
San Pablo-Rumrill	2015	11	1	3.0
San Pablo-Rumrill	2015	11	2	4.3
San Pablo-Rumrill	2015	11	3	4.3
San Pablo-Rumrill	2015	11	4	5.2
San Pablo-Rumrill	2015	11	5	8.2
San Pablo-Rumrill	2015	11	6	9.8
San Pablo-Rumrill	2015	11	7	12.0
San Pablo-Rumrill	2015	11	8	7.7
San Pablo-Rumrill	2015	11	9	6.8
San Pablo-Rumrill	2015	11	10	7.0
San Pablo-Rumrill	2015	11	11	8.3
San Pablo-Rumrill	2015	11	12	10.7
San Pablo-Rumrill	2015	11	13	11.8
San Pablo-Rumrill	2015	11	14	
San Pablo-Rumrill	2015	11	15	
San Pablo-Rumrill	2015	11	16	
San Pablo-Rumrill	2015	11	17	5.9
San Pablo-Rumrill	2015	11	18	6.8
San Pablo-Rumrill	2015	11	19	7.3
San Pablo-Rumrill	2015	11	20	7.8
San Pablo-Rumrill	2015	11	21	13.8
San Pablo-Rumrill	2015	11	22	14.3
San Pablo-Rumrill	2015	11	23	17.4
San Pablo-Rumrill	2015	11	24	8.8
San Pablo-Rumrill	2015	11	25	6.0
San Pablo-Rumrill	2015	11	26	7.4
San Pablo-Rumrill	2015	11	27	6.3
San Pablo-Rumrill	2015	11	28	5.5
San Pablo-Rumrill	2015	11	29	8.3
San Pablo-Rumrill	2015	11	30	11.6
San Pablo-Rumrill	2015	12	1	8.3
San Pablo-Rumrill	2015	12	2	17.7
San Pablo-Rumrill	2015	12	3	14.3
San Pablo-Rumrill	2015	12	4	10.8
San Pablo-Rumrill	2015	12	5	12.8
San Pablo-Rumrill	2015	12	6	9.9
San Pablo-Rumrill	2015	12	7	11.7
San Pablo-Rumrill	2015	12	8	14.5
San Pablo-Rumrill	2015	12	9	9.7
San Pablo-Rumrill	2015	12	10	9.2
San Pablo-Rumrill	2015	12	11	7.3
San Pablo-Rumrill	2015	12	12	8.7
San Pablo-Rumrill	2015	12	13	5.9
San Pablo-Rumrill	2015	12	14	4.3
San Pablo-Rumrill	2015	12	15	6.2

San Pablo-Rumrill	2015	12	16	7.2
San Pablo-Rumrill	2015	12	17	11.3
San Pablo-Rumrill	2015	12	18	8.5
San Pablo-Rumrill	2015	12	19	8.1
San Pablo-Rumrill	2015	12	20	6.2
San Pablo-Rumrill	2015	12	21	4.7
San Pablo-Rumrill	2015	12	22	6.1
San Pablo-Rumrill	2015	12	23	8.4
San Pablo-Rumrill	2015	12	24	6.2
San Pablo-Rumrill	2015	12	25	11.6
San Pablo-Rumrill	2015	12	26	7.9
San Pablo-Rumrill	2015	12	27	14.7
San Pablo-Rumrill	2015	12	28	10.6
San Pablo-Rumrill	2015	12	29	6.8
San Pablo-Rumrill	2015	12	30	13.4
San Pablo-Rumrill	2015	12	31	11.1
Vallejo Tuoloumne St.	2013	1	1	17.3
Vallejo Tuoloumne St.	2013	1	2	13.0
Vallejo Tuoloumne St.	2013	1	3	18.7
Vallejo Tuoloumne St.	2013	1	4	15.6
Vallejo Tuoloumne St.	2013	1	5	28.6
Vallejo Tuoloumne St.	2013	1	6	15.3
Vallejo Tuoloumne St.	2013	1	7	18.4
Vallejo Tuoloumne St.	2013	1	8	22.4
Vallejo Tuoloumne St.	2013	1	9	17.7
Vallejo Tuoloumne St.	2013	1	10	3.2
Vallejo Tuoloumne St.	2013	1	11	8.2
Vallejo Tuoloumne St.	2013	1	12	12.3
Vallejo Tuoloumne St.	2013	1	13	13.2
Vallejo Tuoloumne St.	2013	1	14	11.5
Vallejo Tuoloumne St.	2013	1	15	26.7
Vallejo Tuoloumne St.	2013	1	16	32.8
Vallejo Tuoloumne St.	2013	1	17	25.2
Vallejo Tuoloumne St.	2013	1	18	15.0
Vallejo Tuoloumne St.	2013	1	19	11.1
Vallejo Tuoloumne St.	2013	1	20	13.7
Vallejo Tuoloumne St.	2013	1	21	18.9
Vallejo Tuoloumne St.	2013	1	22	17.3
Vallejo Tuoloumne St.	2013	1	23	23.9
Vallejo Tuoloumne St.	2013	1	24	16.5
Vallejo Tuoloumne St.	2013	1	25	12.3
Vallejo Tuoloumne St.	2013	1	26	4.0
Vallejo Tuoloumne St.	2013	1	27	4.4
Vallejo Tuoloumne St.	2013	1	28	3.8
Vallejo Tuoloumne St.	2013	1	29	10.5
Vallejo Tuoloumne St.	2013	1	30	10.1
Vallejo Tuoloumne St.	2013	1	31	23.0
Vallejo Tuoloumne St.	2013	2	1	12.2
Vallejo Tuoloumne St.	2013	2	2	15.1
Vallejo Tuoloumne St.	2013	2	3	6.6
Vallejo Tuoloumne St.	2013	2	4	9.8
Vallejo Tuoloumne St.	2013	2	5	2.8
Vallejo Tuoloumne St.	2013	2	6	6.3
Vallejo Tuoloumne St.	2013	2	7	6.0
Vallejo Tuoloumne St.	2013	2	8	7.1
Vallejo Tuoloumne St.	2013	2	9	8.0
Vallejo Tuoloumne St.	2013	2	10	14.1
Vallejo Tuoloumne St.	2013	2	11	9.9
Vallejo Tuoloumne St.	2013	2	12	15.5

Vallejo Tuoloumne St.	2013	2	13	13.5
Vallejo Tuoloumne St.	2013	2	14	11.2
Vallejo Tuoloumne St.	2013	2	15	17.0
Vallejo Tuoloumne St.	2013	2	16	16.5
Vallejo Tuoloumne St.	2013	2	17	8.2
Vallejo Tuoloumne St.	2013	2	18	5.2
Vallejo Tuoloumne St.	2013	2	19	3.3
Vallejo Tuoloumne St.	2013	2	20	4.1
Vallejo Tuoloumne St.	2013	2	21	6.3
Vallejo Tuoloumne St.	2013	2	22	8.4
Vallejo Tuoloumne St.	2013	2	23	4.8
Vallejo Tuoloumne St.	2013	2	24	5.1
Vallejo Tuoloumne St.	2013	2	25	8.6
Vallejo Tuoloumne St.	2013	2	26	8.1
Vallejo Tuoloumne St.	2013	2	27	9.5
Vallejo Tuoloumne St.	2013	2	28	5.3
Vallejo Tuoloumne St.	2013	3	1	6.8
Vallejo Tuoloumne St.	2013	3	2	10.9
Vallejo Tuoloumne St.	2013	3	3	8.0
Vallejo Tuoloumne St.	2013	3	4	6.9
Vallejo Tuoloumne St.	2013	3	5	3.2
Vallejo Tuoloumne St.	2013	3	6	4.2
Vallejo Tuoloumne St.	2013	3	7	7.6
Vallejo Tuoloumne St.	2013	3	8	7.5
Vallejo Tuoloumne St.	2013	3	9	5.7
Vallejo Tuoloumne St.	2013	3	10	8.0
Vallejo Tuoloumne St.	2013	3	11	8.9
Vallejo Tuoloumne St.	2013	3	12	9.5
Vallejo Tuoloumne St.	2013	3	13	10.2
Vallejo Tuoloumne St.	2013	3	14	6.0
Vallejo Tuoloumne St.	2013	3	15	5.2
Vallejo Tuoloumne St.	2013	3	16	7.4
Vallejo Tuoloumne St.	2013	3	17	4.1
Vallejo Tuoloumne St.	2013	3	18	7.7
Vallejo Tuoloumne St.	2013	3	19	6.1
Vallejo Tuoloumne St.	2013	3	20	5.2
Vallejo Tuoloumne St.	2013	3	21	4.8
Vallejo Tuoloumne St.	2013	3	22	9.9
Vallejo Tuoloumne St.	2013	3	23	9.1
Vallejo Tuoloumne St.	2013	3	24	10.0
Vallejo Tuoloumne St.	2013	3	25	5.7
Vallejo Tuoloumne St.	2013	3	26	3.9
Vallejo Tuoloumne St.	2013	3	27	5.2
Vallejo Tuoloumne St.	2013	3	28	3.5
Vallejo Tuoloumne St.	2013	3	29	5.3
Vallejo Tuoloumne St.	2013	3	30	4.4
Vallejo Tuoloumne St.	2013	3	31	4.7
Vallejo Tuoloumne St.	2013	4	1	2.6
Vallejo Tuoloumne St.	2013	4	2	4.5
Vallejo Tuoloumne St.	2013	4	3	5.3
Vallejo Tuoloumne St.	2013	4	4	3.6
Vallejo Tuoloumne St.	2013	4	5	3.1
Vallejo Tuoloumne St.	2013	4	6	4.3
Vallejo Tuoloumne St.	2013	4	7	7.0
Vallejo Tuoloumne St.	2013	4	8	
Vallejo Tuoloumne St.	2013	4	9	4.9
Vallejo Tuoloumne St.	2013	4	10	5.5
Vallejo Tuoloumne St.	2013	4	11	6.7
Vallejo Tuoloumne St.	2013	4	12	12.7

Vallejo Tuoloumne St.	2013	4	13	9.3
Vallejo Tuoloumne St.	2013	4	14	4.6
Vallejo Tuoloumne St.	2013	4	15	3.0
Vallejo Tuoloumne St.	2013	4	16	3.7
Vallejo Tuoloumne St.	2013	4	17	5.6
Vallejo Tuoloumne St.	2013	4	18	8.8
Vallejo Tuoloumne St.	2013	4	19	11.0
Vallejo Tuoloumne St.	2013	4	20	8.4
Vallejo Tuoloumne St.	2013	4	21	13.3
Vallejo Tuoloumne St.	2013	4	22	12.2
Vallejo Tuoloumne St.	2013	4	23	7.5
Vallejo Tuoloumne St.	2013	4	24	9.2
Vallejo Tuoloumne St.	2013	4	25	5.2
Vallejo Tuoloumne St.	2013	4	26	9.6
Vallejo Tuoloumne St.	2013	4	27	8.2
Vallejo Tuoloumne St.	2013	4	28	12.6
Vallejo Tuoloumne St.	2013	4	29	11.8
Vallejo Tuoloumne St.	2013	4	30	10.6
Vallejo Tuoloumne St.	2013	5	1	12.2
Vallejo Tuoloumne St.	2013	5	2	18.1
Vallejo Tuoloumne St.	2013	5	3	19.2
Vallejo Tuoloumne St.	2013	5	4	17.1
Vallejo Tuoloumne St.	2013	5	5	10.3
Vallejo Tuoloumne St.	2013	5	6	8.7
Vallejo Tuoloumne St.	2013	5	7	11.2
Vallejo Tuoloumne St.	2013	5	8	5.2
Vallejo Tuoloumne St.	2013	5	9	8.3
Vallejo Tuoloumne St.	2013	5	10	9.3
Vallejo Tuoloumne St.	2013	5	11	10.6
Vallejo Tuoloumne St.	2013	5	12	8.9
Vallejo Tuoloumne St.	2013	5	13	7.0
Vallejo Tuoloumne St.	2013	5	14	13.5
Vallejo Tuoloumne St.	2013	5	15	10.7
Vallejo Tuoloumne St.	2013	5	16	3.8
Vallejo Tuoloumne St.	2013	5	17	4.4
Vallejo Tuoloumne St.	2013	5	18	4.3
Vallejo Tuoloumne St.	2013	5	19	7.1
Vallejo Tuoloumne St.	2013	5	20	12.0
Vallejo Tuoloumne St.	2013	5	21	10.2
Vallejo Tuoloumne St.	2013	5	22	6.2
Vallejo Tuoloumne St.	2013	5	23	9.7
Vallejo Tuoloumne St.	2013	5	24	8.8
Vallejo Tuoloumne St.	2013	5	25	8.2
Vallejo Tuoloumne St.	2013	5	26	1.9
Vallejo Tuoloumne St.	2013	5	27	4.1
Vallejo Tuoloumne St.	2013	5	28	4.3
Vallejo Tuoloumne St.	2013	5	29	4.4
Vallejo Tuoloumne St.	2013	5	30	8.2
Vallejo Tuoloumne St.	2013	5	31	13.2
Vallejo Tuoloumne St.	2013	6	1	16.5
Vallejo Tuoloumne St.	2013	6	2	12.9
Vallejo Tuoloumne St.	2013	6	3	6.8
Vallejo Tuoloumne St.	2013	6	4	6.5
Vallejo Tuoloumne St.	2013	6	5	5.7
Vallejo Tuoloumne St.	2013	6	6	5.1
Vallejo Tuoloumne St.	2013	6	7	11.0
Vallejo Tuoloumne St.	2013	6	8	10.5
Vallejo Tuoloumne St.	2013	6	9	3.6
Vallejo Tuoloumne St.	2013	6	10	4.7

Vallejo Tuoloumne St.	2013	6	11	6.5
Vallejo Tuoloumne St.	2013	6	12	10.8
Vallejo Tuoloumne St.	2013	6	13	8.3
Vallejo Tuoloumne St.	2013	6	14	8.6
Vallejo Tuoloumne St.	2013	6	15	10.1
Vallejo Tuoloumne St.	2013	6	16	7.1
Vallejo Tuoloumne St.	2013	6	17	3.7
Vallejo Tuoloumne St.	2013	6	18	4.0
Vallejo Tuoloumne St.	2013	6	19	4.6
Vallejo Tuoloumne St.	2013	6	20	4.2
Vallejo Tuoloumne St.	2013	6	21	8.3
Vallejo Tuoloumne St.	2013	6	22	8.3
Vallejo Tuoloumne St.	2013	6	23	3.4
Vallejo Tuoloumne St.	2013	6	24	5.1
Vallejo Tuoloumne St.	2013	6	25	3.7
Vallejo Tuoloumne St.	2013	6	26	3.9
Vallejo Tuoloumne St.	2013	6	27	4.0
Vallejo Tuoloumne St.	2013	6	28	8.7
Vallejo Tuoloumne St.	2013	6	29	9.1
Vallejo Tuoloumne St.	2013	6	30	10.2
Vallejo Tuoloumne St.	2013	7	1	8.3
Vallejo Tuoloumne St.	2013	7	2	9.6
Vallejo Tuoloumne St.	2013	7	3	7.7
Vallejo Tuoloumne St.	2013	7	4	17.1
Vallejo Tuoloumne St.	2013	7	5	17.7
Vallejo Tuoloumne St.	2013	7	6	11.7
Vallejo Tuoloumne St.	2013	7	7	9.1
Vallejo Tuoloumne St.	2013	7	8	7.7
Vallejo Tuoloumne St.	2013	7	9	7.0
Vallejo Tuoloumne St.	2013	7	10	4.0
Vallejo Tuoloumne St.	2013	7	11	9.2
Vallejo Tuoloumne St.	2013	7	12	11.3
Vallejo Tuoloumne St.	2013	7	13	13.2
Vallejo Tuoloumne St.	2013	7	14	11.1
Vallejo Tuoloumne St.	2013	7	15	5.3
Vallejo Tuoloumne St.	2013	7	16	4.5
Vallejo Tuoloumne St.	2013	7	17	6.6
Vallejo Tuoloumne St.	2013	7	18	11.2
Vallejo Tuoloumne St.	2013	7	19	13.9
Vallejo Tuoloumne St.	2013	7	20	13.6
Vallejo Tuoloumne St.	2013	7	21	9.6
Vallejo Tuoloumne St.	2013	7	22	7.1
Vallejo Tuoloumne St.	2013	7	23	4.9
Vallejo Tuoloumne St.	2013	7	24	4.9
Vallejo Tuoloumne St.	2013	7	25	5.2
Vallejo Tuoloumne St.	2013	7	26	5.8
Vallejo Tuoloumne St.	2013	7	27	6.2
Vallejo Tuoloumne St.	2013	7	28	11.2
Vallejo Tuoloumne St.	2013	7	29	23.5
Vallejo Tuoloumne St.	2013	7	30	26.0
Vallejo Tuoloumne St.	2013	7	31	10.7
Vallejo Tuoloumne St.	2013	8	1	8.3
Vallejo Tuoloumne St.	2013	8	2	9.8
Vallejo Tuoloumne St.	2013	8	3	8.9
Vallejo Tuoloumne St.	2013	8	4	8.2
Vallejo Tuoloumne St.	2013	8	5	6.0
Vallejo Tuoloumne St.	2013	8	6	5.5
Vallejo Tuoloumne St.	2013	8	7	3.3
Vallejo Tuoloumne St.	2013	8	8	3.1

Vallejo Tuoloumne St.	2013	8	9	3.5
Vallejo Tuoloumne St.	2013	8	10	2.4
Vallejo Tuoloumne St.	2013	8	11	5.5
Vallejo Tuoloumne St.	2013	8	12	8.3
Vallejo Tuoloumne St.	2013	8	13	11.3
Vallejo Tuoloumne St.	2013	8	14	8.0
Vallejo Tuoloumne St.	2013	8	15	3.8
Vallejo Tuoloumne St.	2013	8	16	4.1
Vallejo Tuoloumne St.	2013	8	17	7.3
Vallejo Tuoloumne St.	2013	8	18	12.0
Vallejo Tuoloumne St.	2013	8	19	10.2
Vallejo Tuoloumne St.	2013	8	20	6.8
Vallejo Tuoloumne St.	2013	8	21	6.9
Vallejo Tuoloumne St.	2013	8	22	6.7
Vallejo Tuoloumne St.	2013	8	23	7.2
Vallejo Tuoloumne St.	2013	8	24	5.3
Vallejo Tuoloumne St.	2013	8	25	2.9
Vallejo Tuoloumne St.	2013	8	26	3.9
Vallejo Tuoloumne St.	2013	8	27	6.0
Vallejo Tuoloumne St.	2013	8	28	4.0
Vallejo Tuoloumne St.	2013	8	29	2.5
Vallejo Tuoloumne St.	2013	8	30	5.3
Vallejo Tuoloumne St.	2013	8	31	3.6
Vallejo Tuoloumne St.	2013	9	1	4.7
Vallejo Tuoloumne St.	2013	9	2	3.8
Vallejo Tuoloumne St.	2013	9	3	5.6
Vallejo Tuoloumne St.	2013	9	4	6.2
Vallejo Tuoloumne St.	2013	9	5	6.4
Vallejo Tuoloumne St.	2013	9	6	
Vallejo Tuoloumne St.	2013	9	7	
Vallejo Tuoloumne St.	2013	9	8	
Vallejo Tuoloumne St.	2013	9	9	
Vallejo Tuoloumne St.	2013	9	10	
Vallejo Tuoloumne St.	2013	9	11	6.9
Vallejo Tuoloumne St.	2013	9	12	2.3
Vallejo Tuoloumne St.	2013	9	13	3.1
Vallejo Tuoloumne St.	2013	9	14	5.4
Vallejo Tuoloumne St.	2013	9	15	3.2
Vallejo Tuoloumne St.	2013	9	16	4.6
Vallejo Tuoloumne St.	2013	9	17	4.0
Vallejo Tuoloumne St.	2013	9	18	5.8
Vallejo Tuoloumne St.	2013	9	19	8.1
Vallejo Tuoloumne St.	2013	9	20	3.0
Vallejo Tuoloumne St.	2013	9	21	2.6
Vallejo Tuoloumne St.	2013	9	22	4.0
Vallejo Tuoloumne St.	2013	9	23	5.4
Vallejo Tuoloumne St.	2013	9	24	4.3
Vallejo Tuoloumne St.	2013	9	25	2.4
Vallejo Tuoloumne St.	2013	9	26	3.3
Vallejo Tuoloumne St.	2013	9	27	4.1
Vallejo Tuoloumne St.	2013	9	28	6.3
Vallejo Tuoloumne St.	2013	9	29	3.5
Vallejo Tuoloumne St.	2013	9	30	4.8
Vallejo Tuoloumne St.	2013	10	1	8.5
Vallejo Tuoloumne St.	2013	10	2	5.4
Vallejo Tuoloumne St.	2013	10	3	4.7
Vallejo Tuoloumne St.	2013	10	4	5.7
Vallejo Tuoloumne St.	2013	10	5	6.8
Vallejo Tuoloumne St.	2013	10	6	8.0

Vallejo Tuoloumne St.	2013	10	7	6.3
Vallejo Tuoloumne St.	2013	10	8	7.6
Vallejo Tuoloumne St.	2013	10	9	6.2
Vallejo Tuoloumne St.	2013	10	10	10.5
Vallejo Tuoloumne St.	2013	10	11	10.0
Vallejo Tuoloumne St.	2013	10	12	9.9
Vallejo Tuoloumne St.	2013	10	13	4.4
Vallejo Tuoloumne St.	2013	10	14	5.4
Vallejo Tuoloumne St.	2013	10	15	6.1
Vallejo Tuoloumne St.	2013	10	16	8.3
Vallejo Tuoloumne St.	2013	10	17	9.2
Vallejo Tuoloumne St.	2013	10	18	11.3
Vallejo Tuoloumne St.	2013	10	19	12.2
Vallejo Tuoloumne St.	2013	10	20	9.1
Vallejo Tuoloumne St.	2013	10	21	8.2
Vallejo Tuoloumne St.	2013	10	22	10.8
Vallejo Tuoloumne St.	2013	10	23	8.2
Vallejo Tuoloumne St.	2013	10	24	6.4
Vallejo Tuoloumne St.	2013	10	25	8.9
Vallejo Tuoloumne St.	2013	10	26	11.4
Vallejo Tuoloumne St.	2013	10	27	7.8
Vallejo Tuoloumne St.	2013	10	28	7.4
Vallejo Tuoloumne St.	2013	10	29	6.8
Vallejo Tuoloumne St.	2013	10	30	11.8
Vallejo Tuoloumne St.	2013	10	31	13.7
Vallejo Tuoloumne St.	2013	11	1	15.3
Vallejo Tuoloumne St.	2013	11	2	10.9
Vallejo Tuoloumne St.	2013	11	3	6.7
Vallejo Tuoloumne St.	2013	11	4	4.9
Vallejo Tuoloumne St.	2013	11	5	6.6
Vallejo Tuoloumne St.	2013	11	6	15.2
Vallejo Tuoloumne St.	2013	11	7	12.0
Vallejo Tuoloumne St.	2013	11	8	4.8
Vallejo Tuoloumne St.	2013	11	9	8.7
Vallejo Tuoloumne St.	2013	11	10	12.5
Vallejo Tuoloumne St.	2013	11	11	19.4
Vallejo Tuoloumne St.	2013	11	12	13.0
Vallejo Tuoloumne St.	2013	11	13	7.7
Vallejo Tuoloumne St.	2013	11	14	11.0
Vallejo Tuoloumne St.	2013	11	15	6.9
Vallejo Tuoloumne St.	2013	11	16	5.2
Vallejo Tuoloumne St.	2013	11	17	8.7
Vallejo Tuoloumne St.	2013	11	18	8.3
Vallejo Tuoloumne St.	2013	11	19	7.0
Vallejo Tuoloumne St.	2013	11	20	1.8
Vallejo Tuoloumne St.	2013	11	21	9.4
Vallejo Tuoloumne St.	2013	11	22	8.2
Vallejo Tuoloumne St.	2013	11	23	17.4
Vallejo Tuoloumne St.	2013	11	24	31.7
Vallejo Tuoloumne St.	2013	11	25	29.9
Vallejo Tuoloumne St.	2013	11	26	17.3
Vallejo Tuoloumne St.	2013	11	27	16.4
Vallejo Tuoloumne St.	2013	11	28	14.7
Vallejo Tuoloumne St.	2013	11	29	20.2
Vallejo Tuoloumne St.	2013	11	30	20.5
Vallejo Tuoloumne St.	2013	12	1	21.5
Vallejo Tuoloumne St.	2013	12	2	11.6
Vallejo Tuoloumne St.	2013	12	3	6.5
Vallejo Tuoloumne St.	2013	12	4	13.1

Vallejo Tuoloumne St.	2013	12	5	26.2
Vallejo Tuoloumne St.	2013	12	6	19.7
Vallejo Tuoloumne St.	2013	12	7	7.0
Vallejo Tuoloumne St.	2013	12	8	13.9
Vallejo Tuoloumne St.	2013	12	9	11.2
Vallejo Tuoloumne St.	2013	12	10	17.2
Vallejo Tuoloumne St.	2013	12	11	21.7
Vallejo Tuoloumne St.	2013	12	12	23.5
Vallejo Tuoloumne St.	2013	12	13	25.2
Vallejo Tuoloumne St.	2013	12	14	38.0
Vallejo Tuoloumne St.	2013	12	15	33.7
Vallejo Tuoloumne St.	2013	12	16	28.8
Vallejo Tuoloumne St.	2013	12	17	38.7
Vallejo Tuoloumne St.	2013	12	18	16.4
Vallejo Tuoloumne St.	2013	12	19	6.0
Vallejo Tuoloumne St.	2013	12	20	12.2
Vallejo Tuoloumne St.	2013	12	21	17.4
Vallejo Tuoloumne St.	2013	12	22	31.9
Vallejo Tuoloumne St.	2013	12	23	39.3
Vallejo Tuoloumne St.	2013	12	24	31.3
Vallejo Tuoloumne St.	2013	12	25	36.5
Vallejo Tuoloumne St.	2013	12	26	18.3
Vallejo Tuoloumne St.	2013	12	27	18.4
Vallejo Tuoloumne St.	2013	12	28	19.2
Vallejo Tuoloumne St.	2013	12	29	18.6
Vallejo Tuoloumne St.	2013	12	30	35.5
Vallejo Tuoloumne St.	2013	12	31	42.6
Vallejo Tuoloumne St.	2014	1	1	39.6
Vallejo Tuoloumne St.	2014	1	2	24.0
Vallejo Tuoloumne St.	2014	1	3	30.7
Vallejo Tuoloumne St.	2014	1	4	22.3
Vallejo Tuoloumne St.	2014	1	5	11.7
Vallejo Tuoloumne St.	2014	1	6	23.0
Vallejo Tuoloumne St.	2014	1	7	18.2
Vallejo Tuoloumne St.	2014	1	8	5.2
Vallejo Tuoloumne St.	2014	1	9	3.5
Vallejo Tuoloumne St.	2014	1	10	11.4
Vallejo Tuoloumne St.	2014	1	11	9.8
Vallejo Tuoloumne St.	2014	1	12	5.3
Vallejo Tuoloumne St.	2014	1	13	5.5
Vallejo Tuoloumne St.	2014	1	14	13.6
Vallejo Tuoloumne St.	2014	1	15	20.1
Vallejo Tuoloumne St.	2014	1	16	23.4
Vallejo Tuoloumne St.	2014	1	17	31.0
Vallejo Tuoloumne St.	2014	1	18	17.9
Vallejo Tuoloumne St.	2014	1	19	12.9
Vallejo Tuoloumne St.	2014	1	20	10.7
Vallejo Tuoloumne St.	2014	1	21	12.0
Vallejo Tuoloumne St.	2014	1	22	11.9
Vallejo Tuoloumne St.	2014	1	23	20.0
Vallejo Tuoloumne St.	2014	1	24	24.4
Vallejo Tuoloumne St.	2014	1	25	20.4
Vallejo Tuoloumne St.	2014	1	26	12.0
Vallejo Tuoloumne St.	2014	1	27	7.4
Vallejo Tuoloumne St.	2014	1	28	4.6
Vallejo Tuoloumne St.	2014	1	29	2.8
Vallejo Tuoloumne St.	2014	1	30	2.1
Vallejo Tuoloumne St.	2014	1	31	3.9
Vallejo Tuoloumne St.	2014	2	1	6.3

Vallejo Tuoloumne St.	2014	2	2	4.7
Vallejo Tuoloumne St.	2014	2	3	3.7
Vallejo Tuoloumne St.	2014	2	4	4.5
Vallejo Tuoloumne St.	2014	2	5	4.7
Vallejo Tuoloumne St.	2014	2	6	9.0
Vallejo Tuoloumne St.	2014	2	7	4.3
Vallejo Tuoloumne St.	2014	2	8	1.5
Vallejo Tuoloumne St.	2014	2	9	2.2
Vallejo Tuoloumne St.	2014	2	10	2.0
Vallejo Tuoloumne St.	2014	2	11	2.8
Vallejo Tuoloumne St.	2014	2	12	3.1
Vallejo Tuoloumne St.	2014	2	13	2.8
Vallejo Tuoloumne St.	2014	2	14	1.7
Vallejo Tuoloumne St.	2014	2	15	2.1
Vallejo Tuoloumne St.	2014	2	16	3.3
Vallejo Tuoloumne St.	2014	2	17	3.0
Vallejo Tuoloumne St.	2014	2	18	4.1
Vallejo Tuoloumne St.	2014	2	19	1.8
Vallejo Tuoloumne St.	2014	2	20	
Vallejo Tuoloumne St.	2014	2	21	
Vallejo Tuoloumne St.	2014	2	22	
Vallejo Tuoloumne St.	2014	2	23	
Vallejo Tuoloumne St.	2014	2	24	
Vallejo Tuoloumne St.	2014	2	25	11.6
Vallejo Tuoloumne St.	2014	2	26	9.6
Vallejo Tuoloumne St.	2014	2	27	8.5
Vallejo Tuoloumne St.	2014	2	28	3.8
Vallejo Tuoloumne St.	2014	3	1	3.8
Vallejo Tuoloumne St.	2014	3	2	5.8
Vallejo Tuoloumne St.	2014	3	3	9.3
Vallejo Tuoloumne St.	2014	3	4	5.3
Vallejo Tuoloumne St.	2014	3	5	10.2
Vallejo Tuoloumne St.	2014	3	6	7.9
Vallejo Tuoloumne St.	2014	3	7	6.9
Vallejo Tuoloumne St.	2014	3	8	8.5
Vallejo Tuoloumne St.	2014	3	9	10.1
Vallejo Tuoloumne St.	2014	3	10	5.7
Vallejo Tuoloumne St.	2014	3	11	8.0
Vallejo Tuoloumne St.	2014	3	12	4.5
Vallejo Tuoloumne St.	2014	3	13	7.0
Vallejo Tuoloumne St.	2014	3	14	10.9
Vallejo Tuoloumne St.	2014	3	15	8.0
Vallejo Tuoloumne St.	2014	3	16	8.2
Vallejo Tuoloumne St.	2014	3	17	6.1
Vallejo Tuoloumne St.	2014	3	18	5.5
Vallejo Tuoloumne St.	2014	3	19	7.0
Vallejo Tuoloumne St.	2014	3	20	9.6
Vallejo Tuoloumne St.	2014	3	21	14.7
Vallejo Tuoloumne St.	2014	3	22	13.6
Vallejo Tuoloumne St.	2014	3	23	11.5
Vallejo Tuoloumne St.	2014	3	24	10.4
Vallejo Tuoloumne St.	2014	3	25	5.7
Vallejo Tuoloumne St.	2014	3	26	5.8
Vallejo Tuoloumne St.	2014	3	27	7.7
Vallejo Tuoloumne St.	2014	3	28	7.1
Vallejo Tuoloumne St.	2014	3	29	5.0
Vallejo Tuoloumne St.	2014	3	30	5.4
Vallejo Tuoloumne St.	2014	3	31	4.9
Vallejo Tuoloumne St.	2014	4	1	4.7

Vallejo Tuoloumne St.	2014	4	2	4.1
Vallejo Tuoloumne St.	2014	4	3	6.1
Vallejo Tuoloumne St.	2014	4	4	5.2
Vallejo Tuoloumne St.	2014	4	5	7.1
Vallejo Tuoloumne St.	2014	4	6	8.8
Vallejo Tuoloumne St.	2014	4	7	9.0
Vallejo Tuoloumne St.	2014	4	8	9.8
Vallejo Tuoloumne St.	2014	4	9	6.4
Vallejo Tuoloumne St.	2014	4	10	6.5
Vallejo Tuoloumne St.	2014	4	11	9.8
Vallejo Tuoloumne St.	2014	4	12	9.5
Vallejo Tuoloumne St.	2014	4	13	12.2
Vallejo Tuoloumne St.	2014	4	14	12.0
Vallejo Tuoloumne St.	2014	4	15	14.2
Vallejo Tuoloumne St.	2014	4	16	12.6
Vallejo Tuoloumne St.	2014	4	17	12.7
Vallejo Tuoloumne St.	2014	4	18	8.8
Vallejo Tuoloumne St.	2014	4	19	6.0
Vallejo Tuoloumne St.	2014	4	20	8.2
Vallejo Tuoloumne St.	2014	4	21	15.9
Vallejo Tuoloumne St.	2014	4	22	4.9
Vallejo Tuoloumne St.	2014	4	23	4.4
Vallejo Tuoloumne St.	2014	4	24	7.2
Vallejo Tuoloumne St.	2014	4	25	4.6
Vallejo Tuoloumne St.	2014	4	26	3.7
Vallejo Tuoloumne St.	2014	4	27	7.2
Vallejo Tuoloumne St.	2014	4	28	10.1
Vallejo Tuoloumne St.	2014	4	29	10.2
Vallejo Tuoloumne St.	2014	4	30	10.6
Vallejo Tuoloumne St.	2014	5	1	10.7
Vallejo Tuoloumne St.	2014	5	2	6.5
Vallejo Tuoloumne St.	2014	5	3	4.5
Vallejo Tuoloumne St.	2014	5	4	5.3
Vallejo Tuoloumne St.	2014	5	5	5.2
Vallejo Tuoloumne St.	2014	5	6	7.5
Vallejo Tuoloumne St.	2014	5	7	10.3
Vallejo Tuoloumne St.	2014	5	8	6.8
Vallejo Tuoloumne St.	2014	5	9	5.0
Vallejo Tuoloumne St.	2014	5	10	5.4
Vallejo Tuoloumne St.	2014	5	11	5.1
Vallejo Tuoloumne St.	2014	5	12	8.2
Vallejo Tuoloumne St.	2014	5	13	9.3
Vallejo Tuoloumne St.	2014	5	14	10.6
Vallejo Tuoloumne St.	2014	5	15	8.1
Vallejo Tuoloumne St.	2014	5	16	10.1
Vallejo Tuoloumne St.	2014	5	17	8.6
Vallejo Tuoloumne St.	2014	5	18	3.8
Vallejo Tuoloumne St.	2014	5	19	3.5
Vallejo Tuoloumne St.	2014	5	20	6.8
Vallejo Tuoloumne St.	2014	5	21	12.0
Vallejo Tuoloumne St.	2014	5	22	8.7
Vallejo Tuoloumne St.	2014	5	23	5.8
Vallejo Tuoloumne St.	2014	5	24	10.2
Vallejo Tuoloumne St.	2014	5	25	11.7
Vallejo Tuoloumne St.	2014	5	26	8.4
Vallejo Tuoloumne St.	2014	5	27	10.8
Vallejo Tuoloumne St.	2014	5	28	5.5
Vallejo Tuoloumne St.	2014	5	29	7.4
Vallejo Tuoloumne St.	2014	5	30	16.4

Vallejo Tuoloumne St.	2014	5	31	10.6
Vallejo Tuoloumne St.	2014	6	1	12.4
Vallejo Tuoloumne St.	2014	6	2	6.4
Vallejo Tuoloumne St.	2014	6	3	7.7
Vallejo Tuoloumne St.	2014	6	4	13.8
Vallejo Tuoloumne St.	2014	6	5	17.3
Vallejo Tuoloumne St.	2014	6	6	11.6
Vallejo Tuoloumne St.	2014	6	7	17.7
Vallejo Tuoloumne St.	2014	6	8	15.1
Vallejo Tuoloumne St.	2014	6	9	18.0
Vallejo Tuoloumne St.	2014	6	10	7.8
Vallejo Tuoloumne St.	2014	6	11	8.8
Vallejo Tuoloumne St.	2014	6	12	6.7
Vallejo Tuoloumne St.	2014	6	13	9.3
Vallejo Tuoloumne St.	2014	6	14	14.2
Vallejo Tuoloumne St.	2014	6	15	15.5
Vallejo Tuoloumne St.	2014	6	16	9.9
Vallejo Tuoloumne St.	2014	6	17	8.0
Vallejo Tuoloumne St.	2014	6	18	8.9
Vallejo Tuoloumne St.	2014	6	19	11.3
Vallejo Tuoloumne St.	2014	6	20	8.2
Vallejo Tuoloumne St.	2014	6	21	13.9
Vallejo Tuoloumne St.	2014	6	22	13.0
Vallejo Tuoloumne St.	2014	6	23	12.9
Vallejo Tuoloumne St.	2014	6	24	7.9
Vallejo Tuoloumne St.	2014	6	25	3.9
Vallejo Tuoloumne St.	2014	6	26	3.5
Vallejo Tuoloumne St.	2014	6	27	2.4
Vallejo Tuoloumne St.	2014	6	28	4.7
Vallejo Tuoloumne St.	2014	6	29	8.7
Vallejo Tuoloumne St.	2014	6	30	15.2
Vallejo Tuoloumne St.	2014	7	1	7.6
Vallejo Tuoloumne St.	2014	7	2	6.7
Vallejo Tuoloumne St.	2014	7	3	11.5
Vallejo Tuoloumne St.	2014	7	4	10.5
Vallejo Tuoloumne St.	2014	7	5	8.5
Vallejo Tuoloumne St.	2014	7	6	6.7
Vallejo Tuoloumne St.	2014	7	7	5.4
Vallejo Tuoloumne St.	2014	7	8	3.6
Vallejo Tuoloumne St.	2014	7	9	4.0
Vallejo Tuoloumne St.	2014	7	10	2.9
Vallejo Tuoloumne St.	2014	7	11	2.5
Vallejo Tuoloumne St.	2014	7	12	4.5
Vallejo Tuoloumne St.	2014	7	13	7.5
Vallejo Tuoloumne St.	2014	7	14	14.2
Vallejo Tuoloumne St.	2014	7	15	9.4
Vallejo Tuoloumne St.	2014	7	16	5.9
Vallejo Tuoloumne St.	2014	7	17	4.0
Vallejo Tuoloumne St.	2014	7	18	4.2
Vallejo Tuoloumne St.	2014	7	19	4.5
Vallejo Tuoloumne St.	2014	7	20	3.0
Vallejo Tuoloumne St.	2014	7	21	2.9
Vallejo Tuoloumne St.	2014	7	22	4.2
Vallejo Tuoloumne St.	2014	7	23	5.0
Vallejo Tuoloumne St.	2014	7	24	8.7
Vallejo Tuoloumne St.	2014	7	25	14.9
Vallejo Tuoloumne St.	2014	7	26	15.7
Vallejo Tuoloumne St.	2014	7	27	11.6
Vallejo Tuoloumne St.	2014	7	28	7.2

Vallejo Tuoloumne St.	2014	7	29	6.5
Vallejo Tuoloumne St.	2014	7	30	7.8
Vallejo Tuoloumne St.	2014	7	31	8.4
Vallejo Tuoloumne St.	2014	8	1	12.7
Vallejo Tuoloumne St.	2014	8	2	10.9
Vallejo Tuoloumne St.	2014	8	3	10.2
Vallejo Tuoloumne St.	2014	8	4	6.5
Vallejo Tuoloumne St.	2014	8	5	8.5
Vallejo Tuoloumne St.	2014	8	6	10.5
Vallejo Tuoloumne St.	2014	8	7	11.9
Vallejo Tuoloumne St.	2014	8	8	19.7
Vallejo Tuoloumne St.	2014	8	9	14.2
Vallejo Tuoloumne St.	2014	8	10	8.5
Vallejo Tuoloumne St.	2014	8	11	8.6
Vallejo Tuoloumne St.	2014	8	12	7.7
Vallejo Tuoloumne St.	2014	8	13	7.1
Vallejo Tuoloumne St.	2014	8	14	6.0
Vallejo Tuoloumne St.	2014	8	15	10.0
Vallejo Tuoloumne St.	2014	8	16	10.5
Vallejo Tuoloumne St.	2014	8	17	6.4
Vallejo Tuoloumne St.	2014	8	18	6.9
Vallejo Tuoloumne St.	2014	8	19	5.6
Vallejo Tuoloumne St.	2014	8	20	6.2
Vallejo Tuoloumne St.	2014	8	21	6.2
Vallejo Tuoloumne St.	2014	8	22	9.2
Vallejo Tuoloumne St.	2014	8	23	8.6
Vallejo Tuoloumne St.	2014	8	24	7.2
Vallejo Tuoloumne St.	2014	8	25	7.9
Vallejo Tuoloumne St.	2014	8	26	7.6
Vallejo Tuoloumne St.	2014	8	27	9.2
Vallejo Tuoloumne St.	2014	8	28	7.6
Vallejo Tuoloumne St.	2014	8	29	7.0
Vallejo Tuoloumne St.	2014	8	30	9.7
Vallejo Tuoloumne St.	2014	8	31	10.5
Vallejo Tuoloumne St.	2014	9	1	15.3
Vallejo Tuoloumne St.	2014	9	2	8.7
Vallejo Tuoloumne St.	2014	9	3	10.8
Vallejo Tuoloumne St.	2014	9	4	14.0
Vallejo Tuoloumne St.	2014	9	5	21.0
Vallejo Tuoloumne St.	2014	9	6	22.9
Vallejo Tuoloumne St.	2014	9	7	16.4
Vallejo Tuoloumne St.	2014	9	8	12.5
Vallejo Tuoloumne St.	2014	9	9	11.1
Vallejo Tuoloumne St.	2014	9	10	16.5
Vallejo Tuoloumne St.	2014	9	11	14.7
Vallejo Tuoloumne St.	2014	9	12	12.0
Vallejo Tuoloumne St.	2014	9	13	9.1
Vallejo Tuoloumne St.	2014	9	14	10.5
Vallejo Tuoloumne St.	2014	9	15	9.7
Vallejo Tuoloumne St.	2014	9	16	8.2
Vallejo Tuoloumne St.	2014	9	17	7.3
Vallejo Tuoloumne St.	2014	9	18	7.0
Vallejo Tuoloumne St.	2014	9	19	8.0
Vallejo Tuoloumne St.	2014	9	20	7.0
Vallejo Tuoloumne St.	2014	9	21	6.0
Vallejo Tuoloumne St.	2014	9	22	7.8
Vallejo Tuoloumne St.	2014	9	23	4.3
Vallejo Tuoloumne St.	2014	9	24	3.1
Vallejo Tuoloumne St.	2014	9	25	5.8

Vallejo Tuoloumne St.	2014	9	26	7.4
Vallejo Tuoloumne St.	2014	9	27	9.6
Vallejo Tuoloumne St.	2014	9	28	11.9
Vallejo Tuoloumne St.	2014	9	29	9.9
Vallejo Tuoloumne St.	2014	9	30	9.4
Vallejo Tuoloumne St.	2014	10	1	9.7
Vallejo Tuoloumne St.	2014	10	2	9.7
Vallejo Tuoloumne St.	2014	10	3	12.1
Vallejo Tuoloumne St.	2014	10	4	11.0
Vallejo Tuoloumne St.	2014	10	5	10.9
Vallejo Tuoloumne St.	2014	10	6	9.4
Vallejo Tuoloumne St.	2014	10	7	10.8
Vallejo Tuoloumne St.	2014	10	8	11.9
Vallejo Tuoloumne St.	2014	10	9	8.2
Vallejo Tuoloumne St.	2014	10	10	9.4
Vallejo Tuoloumne St.	2014	10	11	10.9
Vallejo Tuoloumne St.	2014	10	12	9.4
Vallejo Tuoloumne St.	2014	10	13	11.5
Vallejo Tuoloumne St.	2014	10	14	11.3
Vallejo Tuoloumne St.	2014	10	15	7.5
Vallejo Tuoloumne St.	2014	10	16	7.0
Vallejo Tuoloumne St.	2014	10	17	7.6
Vallejo Tuoloumne St.	2014	10	18	7.5
Vallejo Tuoloumne St.	2014	10	19	5.7
Vallejo Tuoloumne St.	2014	10	20	5.2
Vallejo Tuoloumne St.	2014	10	21	6.3
Vallejo Tuoloumne St.	2014	10	22	8.2
Vallejo Tuoloumne St.	2014	10	23	9.1
Vallejo Tuoloumne St.	2014	10	24	6.5
Vallejo Tuoloumne St.	2014	10	25	7.5
Vallejo Tuoloumne St.	2014	10	26	9.0
Vallejo Tuoloumne St.	2014	10	27	8.8
Vallejo Tuoloumne St.	2014	10	28	9.6
Vallejo Tuoloumne St.	2014	10	29	13.0
Vallejo Tuoloumne St.	2014	10	30	12.5
Vallejo Tuoloumne St.	2014	10	31	7.5
Vallejo Tuoloumne St.	2014	11	1	6.8
Vallejo Tuoloumne St.	2014	11	2	10.4
Vallejo Tuoloumne St.	2014	11	3	11.7
Vallejo Tuoloumne St.	2014	11	4	15.7
Vallejo Tuoloumne St.	2014	11	5	20.7
Vallejo Tuoloumne St.	2014	11	6	29.7
Vallejo Tuoloumne St.	2014	11	7	15.0
Vallejo Tuoloumne St.	2014	11	8	17.1
Vallejo Tuoloumne St.	2014	11	9	16.9
Vallejo Tuoloumne St.	2014	11	10	13.4
Vallejo Tuoloumne St.	2014	11	11	8.4
Vallejo Tuoloumne St.	2014	11	12	9.2
Vallejo Tuoloumne St.	2014	11	13	7.5
Vallejo Tuoloumne St.	2014	11	14	9.0
Vallejo Tuoloumne St.	2014	11	15	11.9
Vallejo Tuoloumne St.	2014	11	16	9.8
Vallejo Tuoloumne St.	2014	11	17	7.8
Vallejo Tuoloumne St.	2014	11	18	11.2
Vallejo Tuoloumne St.	2014	11	19	19.8
Vallejo Tuoloumne St.	2014	11	20	20.0
Vallejo Tuoloumne St.	2014	11	21	17.9
Vallejo Tuoloumne St.	2014	11	22	8.8
Vallejo Tuoloumne St.	2014	11	23	11.7

Vallejo Tuoloumne St.	2014	11	24	17.1
Vallejo Tuoloumne St.	2014	11	25	19.0
Vallejo Tuoloumne St.	2014	11	26	21.4
Vallejo Tuoloumne St.	2014	11	27	30.9
Vallejo Tuoloumne St.	2014	11	28	14.2
Vallejo Tuoloumne St.	2014	11	29	10.7
Vallejo Tuoloumne St.	2014	11	30	9.7
Vallejo Tuoloumne St.	2014	12	1	10.2
Vallejo Tuoloumne St.	2014	12	2	8.5
Vallejo Tuoloumne St.	2014	12	3	6.7
Vallejo Tuoloumne St.	2014	12	4	5.6
Vallejo Tuoloumne St.	2014	12	5	10.4
Vallejo Tuoloumne St.	2014	12	6	10.1
Vallejo Tuoloumne St.	2014	12	7	12.6
Vallejo Tuoloumne St.	2014	12	8	19.0
Vallejo Tuoloumne St.	2014	12	9	29.5
Vallejo Tuoloumne St.	2014	12	10	15.9
Vallejo Tuoloumne St.	2014	12	11	6.3
Vallejo Tuoloumne St.	2014	12	12	12.6
Vallejo Tuoloumne St.	2014	12	13	17.5
Vallejo Tuoloumne St.	2014	12	14	15.5
Vallejo Tuoloumne St.	2014	12	15	10.2
Vallejo Tuoloumne St.	2014	12	16	10.5
Vallejo Tuoloumne St.	2014	12	17	8.9
Vallejo Tuoloumne St.	2014	12	18	14.0
Vallejo Tuoloumne St.	2014	12	19	12.6
Vallejo Tuoloumne St.	2014	12	20	21.0
Vallejo Tuoloumne St.	2014	12	21	6.0
Vallejo Tuoloumne St.	2014	12	22	11.7
Vallejo Tuoloumne St.	2014	12	23	13.3
Vallejo Tuoloumne St.	2014	12	24	7.6
Vallejo Tuoloumne St.	2014	12	25	8.4
Vallejo Tuoloumne St.	2014	12	26	14.7
Vallejo Tuoloumne St.	2014	12	27	22.0
Vallejo Tuoloumne St.	2014	12	28	26.9
Vallejo Tuoloumne St.	2014	12	29	15.7
Vallejo Tuoloumne St.	2014	12	30	11.2
Vallejo Tuoloumne St.	2014	12	31	19.7
Vallejo Tuoloumne St.	2015	1	1	24.5
Vallejo Tuoloumne St.	2015	1	2	30.2
Vallejo Tuoloumne St.	2015	1	3	38.0
Vallejo Tuoloumne St.	2015	1	4	32.5
Vallejo Tuoloumne St.	2015	1	5	28.6
Vallejo Tuoloumne St.	2015	1	6	28.9
Vallejo Tuoloumne St.	2015	1	7	21.3
Vallejo Tuoloumne St.	2015	1	8	41.4
Vallejo Tuoloumne St.	2015	1	9	29.5
Vallejo Tuoloumne St.	2015	1	10	29.7
Vallejo Tuoloumne St.	2015	1	11	27.0
Vallejo Tuoloumne St.	2015	1	12	13.7
Vallejo Tuoloumne St.	2015	1	13	15.3
Vallejo Tuoloumne St.	2015	1	14	39.1
Vallejo Tuoloumne St.	2015	1	15	31.9
Vallejo Tuoloumne St.	2015	1	16	30.7
Vallejo Tuoloumne St.	2015	1	17	20.0
Vallejo Tuoloumne St.	2015	1	18	20.2
Vallejo Tuoloumne St.	2015	1	19	19.4
Vallejo Tuoloumne St.	2015	1	20	20.0
Vallejo Tuoloumne St.	2015	1	21	18.1

Vallejo Tuoloumne St.	2015	1	22	24.1
Vallejo Tuoloumne St.	2015	1	23	29.4
Vallejo Tuoloumne St.	2015	1	24	28.2
Vallejo Tuoloumne St.	2015	1	25	24.6
Vallejo Tuoloumne St.	2015	1	26	25.1
Vallejo Tuoloumne St.	2015	1	27	22.5
Vallejo Tuoloumne St.	2015	1	28	26.1
Vallejo Tuoloumne St.	2015	1	29	19.8
Vallejo Tuoloumne St.	2015	1	30	17.5
Vallejo Tuoloumne St.	2015	1	31	13.6
Vallejo Tuoloumne St.	2015	2	1	32.6
Vallejo Tuoloumne St.	2015	2	2	32.0
Vallejo Tuoloumne St.	2015	2	3	19.2
Vallejo Tuoloumne St.	2015	2	4	18.7
Vallejo Tuoloumne St.	2015	2	5	7.7
Vallejo Tuoloumne St.	2015	2	6	2.3
Vallejo Tuoloumne St.	2015	2	7	7.9
Vallejo Tuoloumne St.	2015	2	8	6.2
Vallejo Tuoloumne St.	2015	2	9	8.5
Vallejo Tuoloumne St.	2015	2	10	6.9
Vallejo Tuoloumne St.	2015	2	11	8.0
Vallejo Tuoloumne St.	2015	2	12	8.4
Vallejo Tuoloumne St.	2015	2	13	10.8
Vallejo Tuoloumne St.	2015	2	14	11.6
Vallejo Tuoloumne St.	2015	2	15	12.5
Vallejo Tuoloumne St.	2015	2	16	11.0
Vallejo Tuoloumne St.	2015	2	17	8.6
Vallejo Tuoloumne St.	2015	2	18	7.2
Vallejo Tuoloumne St.	2015	2	19	16.0
Vallejo Tuoloumne St.	2015	2	20	9.6
Vallejo Tuoloumne St.	2015	2	21	13.6
Vallejo Tuoloumne St.	2015	2	22	12.6
Vallejo Tuoloumne St.	2015	2	23	11.7
Vallejo Tuoloumne St.	2015	2	24	5.5
Vallejo Tuoloumne St.	2015	2	25	8.7
Vallejo Tuoloumne St.	2015	2	26	6.8
Vallejo Tuoloumne St.	2015	2	27	1.7
Vallejo Tuoloumne St.	2015	2	28	4.7
Vallejo Tuoloumne St.	2015	3	1	7.1
Vallejo Tuoloumne St.	2015	3	2	8.5
Vallejo Tuoloumne St.	2015	3	3	9.1
Vallejo Tuoloumne St.	2015	3	4	9.0
Vallejo Tuoloumne St.	2015	3	5	10.4
Vallejo Tuoloumne St.	2015	3	6	10.5
Vallejo Tuoloumne St.	2015	3	7	9.7
Vallejo Tuoloumne St.	2015	3	8	10.5
Vallejo Tuoloumne St.	2015	3	9	12.2
Vallejo Tuoloumne St.	2015	3	10	13.7
Vallejo Tuoloumne St.	2015	3	11	7.5
Vallejo Tuoloumne St.	2015	3	12	5.2
Vallejo Tuoloumne St.	2015	3	13	4.0
Vallejo Tuoloumne St.	2015	3	14	8.6
Vallejo Tuoloumne St.	2015	3	15	5.1
Vallejo Tuoloumne St.	2015	3	16	5.2
Vallejo Tuoloumne St.	2015	3	17	2.8
Vallejo Tuoloumne St.	2015	3	18	3.6
Vallejo Tuoloumne St.	2015	3	19	8.5
Vallejo Tuoloumne St.	2015	3	20	6.3
Vallejo Tuoloumne St.	2015	3	21	3.9

Vallejo Tuoloumne St.	2015	3	22	5.0
Vallejo Tuoloumne St.	2015	3	23	4.2
Vallejo Tuoloumne St.	2015	3	24	5.5
Vallejo Tuoloumne St.	2015	3	25	6.9
Vallejo Tuoloumne St.	2015	3	26	8.6
Vallejo Tuoloumne St.	2015	3	27	6.5
Vallejo Tuoloumne St.	2015	3	28	7.0
Vallejo Tuoloumne St.	2015	3	29	9.9
Vallejo Tuoloumne St.	2015	3	30	9.3
Vallejo Tuoloumne St.	2015	3	31	2.2
Vallejo Tuoloumne St.	2015	4	1	3.1
Vallejo Tuoloumne St.	2015	4	2	4.4
Vallejo Tuoloumne St.	2015	4	3	9.5
Vallejo Tuoloumne St.	2015	4	4	3.3
Vallejo Tuoloumne St.	2015	4	5	2.1
Vallejo Tuoloumne St.	2015	4	6	2.1
Vallejo Tuoloumne St.	2015	4	7	1.3
Vallejo Tuoloumne St.	2015	4	8	2.3
Vallejo Tuoloumne St.	2015	4	9	4.6
Vallejo Tuoloumne St.	2015	4	10	3.5
Vallejo Tuoloumne St.	2015	4	11	3.0
Vallejo Tuoloumne St.	2015	4	12	3.8
Vallejo Tuoloumne St.	2015	4	13	6.1
Vallejo Tuoloumne St.	2015	4	14	5.5
Vallejo Tuoloumne St.	2015	4	15	4.5
Vallejo Tuoloumne St.	2015	4	16	3.8
Vallejo Tuoloumne St.	2015	4	17	8.4
Vallejo Tuoloumne St.	2015	4	18	10.2
Vallejo Tuoloumne St.	2015	4	19	7.2
Vallejo Tuoloumne St.	2015	4	20	7.7
Vallejo Tuoloumne St.	2015	4	21	5.4
Vallejo Tuoloumne St.	2015	4	22	10.7
Vallejo Tuoloumne St.	2015	4	23	13.6
Vallejo Tuoloumne St.	2015	4	24	4.0
Vallejo Tuoloumne St.	2015	4	25	2.1
Vallejo Tuoloumne St.	2015	4	26	3.1
Vallejo Tuoloumne St.	2015	4	27	3.6
Vallejo Tuoloumne St.	2015	4	28	5.2
Vallejo Tuoloumne St.	2015	4	29	10.5
Vallejo Tuoloumne St.	2015	4	30	11.3
Vallejo Tuoloumne St.	2015	5	1	10.3
Vallejo Tuoloumne St.	2015	5	2	10.1
Vallejo Tuoloumne St.	2015	5	3	6.5
Vallejo Tuoloumne St.	2015	5	4	7.0
Vallejo Tuoloumne St.	2015	5	5	10.0
Vallejo Tuoloumne St.	2015	5	6	9.9
Vallejo Tuoloumne St.	2015	5	7	7.8
Vallejo Tuoloumne St.	2015	5	8	12.5
Vallejo Tuoloumne St.	2015	5	9	6.9
Vallejo Tuoloumne St.	2015	5	10	8.0
Vallejo Tuoloumne St.	2015	5	11	6.6
Vallejo Tuoloumne St.	2015	5	12	4.4
Vallejo Tuoloumne St.	2015	5	13	3.0
Vallejo Tuoloumne St.	2015	5	14	3.6
Vallejo Tuoloumne St.	2015	5	15	3.7
Vallejo Tuoloumne St.	2015	5	16	5.3
Vallejo Tuoloumne St.	2015	5	17	3.1
Vallejo Tuoloumne St.	2015	5	18	3.5
Vallejo Tuoloumne St.	2015	5	19	4.7

Vallejo Tuoloumne St.	2015	5	20	3.8
Vallejo Tuoloumne St.	2015	5	21	2.5
Vallejo Tuoloumne St.	2015	5	22	3.6
Vallejo Tuoloumne St.	2015	5	23	8.6
Vallejo Tuoloumne St.	2015	5	24	6.7
Vallejo Tuoloumne St.	2015	5	25	2.3
Vallejo Tuoloumne St.	2015	5	26	2.1
Vallejo Tuoloumne St.	2015	5	27	3.6
Vallejo Tuoloumne St.	2015	5	28	3.7
Vallejo Tuoloumne St.	2015	5	29	3.0
Vallejo Tuoloumne St.	2015	5	30	4.3
Vallejo Tuoloumne St.	2015	5	31	5.2
Vallejo Tuoloumne St.	2015	6	1	3.0
Vallejo Tuoloumne St.	2015	6	2	2.0
Vallejo Tuoloumne St.	2015	6	3	6.2
Vallejo Tuoloumne St.	2015	6	4	8.8
Vallejo Tuoloumne St.	2015	6	5	9.2
Vallejo Tuoloumne St.	2015	6	6	3.5
Vallejo Tuoloumne St.	2015	6	7	2.1
Vallejo Tuoloumne St.	2015	6	8	4.0
Vallejo Tuoloumne St.	2015	6	9	3.0
Vallejo Tuoloumne St.	2015	6	10	4.4
Vallejo Tuoloumne St.	2015	6	11	8.3
Vallejo Tuoloumne St.	2015	6	12	10.2
Vallejo Tuoloumne St.	2015	6	13	15.2
Vallejo Tuoloumne St.	2015	6	14	17.0
Vallejo Tuoloumne St.	2015	6	15	13.8
Vallejo Tuoloumne St.	2015	6	16	12.0
Vallejo Tuoloumne St.	2015	6	17	12.9
Vallejo Tuoloumne St.	2015	6	18	8.9
Vallejo Tuoloumne St.	2015	6	19	7.6
Vallejo Tuoloumne St.	2015	6	20	8.4
Vallejo Tuoloumne St.	2015	6	21	7.5
Vallejo Tuoloumne St.	2015	6	22	5.9
Vallejo Tuoloumne St.	2015	6	23	10.7
Vallejo Tuoloumne St.	2015	6	24	10.0
Vallejo Tuoloumne St.	2015	6	25	10.5
Vallejo Tuoloumne St.	2015	6	26	8.6
Vallejo Tuoloumne St.	2015	6	27	3.3
Vallejo Tuoloumne St.	2015	6	28	1.9
Vallejo Tuoloumne St.	2015	6	29	2.8
Vallejo Tuoloumne St.	2015	6	30	6.2
Vallejo Tuoloumne St.	2015	7	1	4.5
Vallejo Tuoloumne St.	2015	7	2	3.6
Vallejo Tuoloumne St.	2015	7	3	2.4
Vallejo Tuoloumne St.	2015	7	4	2.5
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Vallejo Tuoloumne St.	2015	7	6	3.1
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Vallejo Tuoloumne St.	2015	7	8	1.5
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Vallejo Tuoloumne St.	2015	7	10	4.4
Vallejo Tuoloumne St.	2015	7	11	1.4
Vallejo Tuoloumne St.	2015	7	12	2.6
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Vallejo Tuoloumne St.	2015	8	3	1.5
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Vallejo Tuoloumne St.	2015	8	14	1.3
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Vallejo Tuoloumne St.	2015	8	17	27.5
Vallejo Tuoloumne St.	2015	8	18	
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Vallejo Tuoloumne St.	2015	8	20	
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Vallejo Tuoloumne St.	2015	12	29	
Vallejo Tuoloumne St.	2015	12	30	
Vallejo Tuoloumne St.	2015	12	31	

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Bay Area Air Quality Management District
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Staff Report

Proposed Amendments
to
Regulation 12, Miscellaneous Standards of Performance
Rule 12, Flares at Petroleum Refineries

March 3, 2006

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I. EXECUTIVE SUMMARY

On July 20, 2005, the Bay Area Air Quality Management District (District) adopted a ground breaking refinery flare control rule (Regulation 12: Miscellaneous Standards of Performance, Rule 12: Flares at Petroleum Refineries). The new rule is intended to reduce emissions from flares at petroleum refineries by reducing the magnitude and duration of flaring events.

The new rule requires each Bay Area refinery to develop and implement a Flare Minimization Plan (FMP) for each flare subject to the rule and to update the plan annually. In addition, the refiners must conduct a causal analysis when significant flaring occurs and develop and submit an annual report to provide information about the cause of flaring at lower flow rates. Refiners must operate their flares in accordance with the FMP except for flaring in emergency situations. The initial FMP for each refinery must be submitted to the District by August 1, 2006.

The rule embodies a continuous improvement process focused on reducing all air pollutants from all flaring. A fundamental requirement of the regulation is the investigation to determine primary cause and contributing factors for flaring (causal analysis) in order to develop prevention measures to avoid or minimize flaring. The rule includes two requirements for submitting an analysis of the cause(s) of flaring depending on the amount of vent gas flared.

The first reporting requirement calls for submission of a causal analysis report to the District within 60 days following the end of the month in which a reportable flaring event occurs. A reportable flaring event is currently defined as any flaring where more than 500,000 standard cubic feet per day (scfd) of vent gas is flared. The second reporting provision requires an annual report to the Air Pollution Control Officer (APCO) that summarizes the use of a flare at rates less than 500,000 scfd where sulfur dioxide emissions are greater than 500 pounds per day. The summary must include the reasons for the flaring and prevention measures considered or implemented. Reporting of flaring resulting in sulfur dioxide emissions in excess of 500 pounds (regardless of the flow rate) is required twelve months after approval of the initial FMP and annually thereafter. Both provisions require determination of cause, identification of prevention measures and incorporation of prevention measures into the FMP.

These provisions are the subject of the proposed rule amendments. The proposal is to change the annual reporting requirement for lower-volume flaring (less than 500,000 scfd) where emissions of sulfur dioxide exceed 500 pounds per day. The change would require the analysis and reporting of this lower-volume flaring to occur on the same schedule specified for flaring events greater than 500,000 scfd, i.e., within 60 days following the end of the month in which a reportable flaring event occurs. The proposed change would take effect upon adoption by the District Board of Directors. There have been 49 of these lower-volume flaring events over the past two years; 28 in 2004 and 21 in 2005.

The reason for the proposed amendment is to ensure that the prevention measures developed from the investigations into lower-volume flaring with sulfur dioxide emissions greater than 500 pounds per day are incorporated into the initial FMPs.

In addition, the proposal would specify that the report of causal analysis for a reportable flaring event must include the volume of vent gas flared and the calculated emissions (methane, non-methane hydrocarbon and sulfur dioxide). This information is necessary to provide the context necessary for a comprehensive report. The proposal would also clarify the application of the causal analysis provision for refineries with cascade and backup systems.

II. BACKGROUND

The District's flare control rule, Regulation 12, Rule 12, recognizes that a flare is first and foremost a safety device. Specifically, the rule allows flaring in an emergency if necessary to prevent an accident, hazard or release of vent gas directly to the atmosphere. All other flaring must be consistent with the FMP developed by each refinery.

The FMP includes information about the flare system or systems at the refinery and a list of feasible prevention measures to be implemented on an expedited schedule. The prevention measures are to be developed in conjunction with the causal analysis of reportable flaring events and the annual reports of the analysis of lower-volume flaring with sulfur dioxide emissions in excess of 500 pounds per day.

The current regulation includes a requirement to conduct an investigation to evaluate any reportable flaring event, i.e., flaring where more than 500,000 scfd of vent gas is combusted. The purpose of the investigation is to identify the cause (or causes) of the flaring and the means to avoid flaring from that cause in the future if feasible. In addition to the causal analyses for reportable flaring events, beginning 12 months after approval of the initial FMP, each facility is required to submit an annual report to the District that includes an evaluation of flaring at volumes less than 500,000 scfd where the calculated sulfur dioxide emissions are greater than 500 pounds per day. These formal evaluation processes will ensure that each refinery makes continuous improvement and progress toward minimizing flaring from any cause.

All feasible prevention measures identified through either of the reporting methods described above are to be incorporated in the FMP with a schedule for expeditious implementation of those measures. The FMP must be updated annually to incorporate the prevention measures identified during the previous year as well as any significant changes in process equipment or operational procedures related to flares. Any flaring that occurs after submission of the initial

FMP must be consistent with the current plan.

The requirement to conduct an investigation into the reasons for flaring was originally proposed in Regulation 12, Rule 11: Flare Monitoring at Petroleum Refineries. Under that regulation, for any 24-hour period during which more than 1 million standard cubic feet (scf) of vent gas is flared, a description of the flaring including the cause, time of occurrence and duration, the source or equipment from which the vent gas originated, and any measures taken to reduce or eliminate flaring must be submitted to the District in a monthly report. This provision was effective on the date of rule adoption, June 4, 2003. The data included in the monthly report became more encompassing as other provisions in the rule became effective; specifically the requirements to continuously monitor vent gas flow and to sample vent gas and analyze for composition. These data were used to consider various thresholds of a causal analysis in the development of the flare control rule.

A lower threshold to conduct a causal analysis was proposed for the new flare control rule, Regulation 12, Rule 12: Flares at Petroleum Refineries. Two reporting requirements were developed to cover all significant flaring events in an efficient and thorough manner. The first reporting requirement calls for a causal analysis to be completed where more than 500,000 scfd of vent gas is flared. This report is due 60 days following the end of the month in which the flaring event occurs. The second reporting provision requires a summary of the use of a flare at rates less than 500,000 scfd of vent gas where sulfur dioxide (SO_2) emissions are greater than 500 pounds per day. This report is due annually effective 12 months after approval of the original FMP.

A breakdown of the number of flaring events for 2004 and 2005 is shown in Table 1. This data was obtained from the monthly reports required by the flare monitoring rule. The 2005 data incorporates January through November 2005. Also, the Tesoro data excludes the Ammonia Plant flare, because of an ongoing verification audit.

Table 1. Summary of Flaring Events at Bay Area Refineries

Facility	**Events Less than 500,000 scfd and Greater than 500 lbs SO2 per day**		**Events Greater than 500,000 scfd**	
	2004	2005[a]	2004	2005[a]
Chevron	0	2	38	21
ConocoPhillips	8	9	12	38
Shell	0	1	89	30
Tesoro[b]	4	2	72	64
Valero	16	7	90	21
Total	28	21	301	174

[a] Data through November 2005

[b] Excludes Ammonia Plant Flare

The data in the table shows that most flaring would require a causal analysis under the existing threshold for causal analysis (greater than 500,000 scfd vent gas). The lower threshold represents a small portion of all flaring, but these lower-flow events with sulfur dioxide emissions at levels of concern may have different causes than the greater than 500,000 scfd events. Staff has concluded that requiring analysis of certain lower-volume flaring (greater than 500 pounds per day SO_2) for inclusion in the initial FMP will insure that each refinery is creating a flare minimization strategy that will best address the causes of all flaring of concern at each refinery.

III. PROPOSED AMENDMENTS

The proposed amendments will change the annual reporting provision for the flaring events of less than 500,000 scfd but greater than 500 lbs SO_2 per day. The change would require the analysis and reporting of this lower-volume flaring to occur on the same schedule specified for reportable flaring events, i.e., within 60 days following the end of the month in which the flaring occurs. The proposed change would take effect upon adoption by the District Board of Directors.

Specifically, the proposal would amend the current definition of “reportable flaring event” for which a causal analysis is required within 60 days of the end of the month in which the flaring occurs, i.e., any flaring of more than 500,000 scfd vent gas, to include any flaring at rates below 500,000 scfd where the calculated SO_2 emissions are greater than 500 pounds per day. The current rule requires the owner or operator of a flare subject to the rule to submit an annual report covering such lower-volume flaring beginning 12 months after approval of a refinery’s initial FMP. By moving up the schedule for analysis of lower-volume flaring with emissions of SO_2 in excess of 500 pounds per day, the District will insure that the initial FMPs will account for and address the causes of all significant flaring.

The proposal also includes an amendment specifying that the causal analysis must include the calculated methane, non-methane and sulfur dioxide emissions. The reports currently submitted include this information or the data necessary to calculate this information. This amendment will insure that all refineries submit this information a manner most efficient for staff use.

Finally, the definition of a reportable flaring event has been amended to clarify that the total volume is calculated on a cumulative basis for flare systems. This clarification is necessary to identify when a reportable flaring event begins and ends for systems that are operated as a backup or staged flares or flares in a cascade (common piping configured either in series or parallel where the flare vent gas may be distributed to more than one flare).

IV. Emissions

Flares produce air pollutants through two primary mechanisms. The first mechanism is incomplete combustion of a gas stream, because like all combustion devices, flares do not combust all of the fuel directed to them. The second mechanism of pollutant generation is the oxidation of flare gases to form other pollutants. As an example, the gases that are burned in flares typically contain sulfur in varying amounts. Combustion oxidizes these sulfur compounds to form sulfur dioxide, a criteria pollutant. In addition, combustion also produces relatively minor amounts of nitrogen oxides through oxidation of the nitrogen in flare gas or atmospheric nitrogen in combustion air. The flare control rule adopted by the District last year will reduce emissions from flaring as described in the staff report for Regulation 12, Rule 12: Flares at Petroleum Refineries.

The proposed amendments are administrative in nature and will not have a significant emissions impact. The amendments will require a causal analysis for the lower-volume events with SO_2 emissions in excess of 500 pounds per day on the same schedule as the higher volume events. This will insure that prevention measures for these lower-volume events are incorporated into the initial FMPs. In addition, the proposed amendments include a clarification of the application of the requirements to cascade, staged or backup flare systems and a provision to ensure that the report to the District providing the causal analysis for a flaring event includes calculated emissions for that event. No change in the amount of emission reductions from implementation of the flare control rule as adopted July 20, 2005 are expected as a result of the proposed amendments; however, some reductions may occur earlier than under the current rule if prevention measures for these lower-volume flaring events are identified and implemented through the initial FMPs.

Current Flare Emission Estimate

The estimated emissions from flares, on an average daily basis for all facilities in 2004, are approximately 2 tons/day of total organic compounds (approximately 1.5 tons/day of non-methane organic compounds and 0.5 tons/day methane). The daily emissions range from 0 to 12 tons/day of total organic compounds. For sulfur dioxide, the average daily emission rate is approximately 4 tons/day and ranges from 0 to 61 tons/day.

To illustrate the offsite impact of emissions associated with lower-volume flaring, staff modeled two days (April 21 and 22, 2004) of flaring at the Chevron refinery where the volume of vent gas flared was less than one-million standard cubic feet per calendar day and the calculated sulfur dioxide emissions were greater than 500 pounds per day. The results of the modeling are illustrated in the Figure 1.

Figure 1. Modeled Lower-Volume Flaring Event

April 21 and 22, 2004 Chevron Flaring Event
Maximum 1-hour SO2 Air Concentration (ppb)

SO2 Ambient Air Quality Standard
California 1-hour: 250 ppb

In Figure 1, above, Richmond area monitoring stations (Gertrude, Richmond - 7th Street, Castro Street, and Golden Gate) are indicated by the white dots. The boxes next to each station contain the recorded concentration of SO_2 in parts per billion (ppb) at that station for April 21 (upper, purple) and April 22 (lower, blue). The areas within the 10 ppb isopleths (April 21 near the Richmond - 7th Street Station in purple and April 22 southeast of the Golden Gate Station in blue) show the modeled ground level concentration of SO_2 in ppb. Chevron's flares are located directly west of the Gertrude Station (in red).

On each of the two days several flares were in operation at rates less than one-million standard cubic feet per day with calculated SO_2 emissions of over 7500 and 2500 pounds per day, respectively. The isopleths show that the modeling estimates concentrations consistent with data from nearby ambient air quality monitors. The modeling shows a one-hour maximum concentration of 72 ppb for April 21 and 32 ppb for April 22. The ambient air quality standard for a one-hour concentration of SO_2 is 250 ppb. Nevertheless, these isopleths show an impact on the nearby community. For this reason, the inclusion of prevention measures directed at lower-volume flaring with SO_2 emissions greater than 500 pounds per day in the initial FMP will lessen the emissions impact of flaring on those who live and work within affected areas.

V. ECONOMIC IMPACTS

A. Introduction

This section discusses the estimated costs associated with the proposed amendments. The California Health & Safety Code states, in part, that districts shall endeavor to achieve and maintain State ambient air quality standards for ozone, carbon monoxide, sulfur dioxide, and nitrogen dioxide by the earliest practicable date. In developing regulations to achieve this objective, districts shall consider the cost-effectiveness of their air quality programs, rules, regulations, and enforcement practices in addition to other relevant factors, and shall strive to achieve the most efficient methods of air pollution control. However, priority shall be placed upon expeditious progress toward the goal of healthful air.[1]

Regulation 12-12 requires refineries to develop the prevention measures they will implement to reduce flaring. The regulation by design ensures that the most cost effective means for achieving this goal will be implemented. That is, it is reasonable to expect that each refinery, given the flexibility provided by the structure of the rule, will include the most cost-effective prevention measures available for each iteration of the flare minimization plan, thus insuring the continuous improvement at the least cost.

This was the determination of the District in adopting the current flare control rule. The conclusion is equally applicable to the proposed amendments.

B. Discussion

Determination and Reporting of Cause

The cost for the determining and reporting of cause is dependant on the number of reportable flaring events and the complexity of each event. The data from the flare monitoring monthly reports, which was used in the cost analysis for Regulation 12-12, shows 243 occurrences where the volume of vent gas flared was greater than 500,000 scfd in 2004 for all facilities. In the development of Regulation 12-12, staff estimated costs of determining and reporting cause at an hourly rate of $50.00 per hour for 12 hours per event. The total was approximately $145,800 for all facilities per year. The cost for an individual refinery will be much less. Moreover, staff expected this cost to drop in time as

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[1] California Health and Safety Code section 40910

facilities minimize the number of events and become more proficient in investigations.

The initial cost analysis was based on a hypothetical 67 events per facility. A review of Table 1 shows that, even including lower-volume flaring where sulfur dioxide emissions exceed 500 pounds per day, no facility would have had reportable flaring events in excess of 67 events in 2005. Staff anticipates the downward trend in the number of reportable flaring events to continue, with a concomitant drop in these costs. Therefore, although there may be additional causal analyses required in the first year (or two) of implementation of the flare control rule under this proposal, the additional causal analyses required by these amendments will create no significant increase in the costs assumed for the current version of Regulation 12, Rule 12: Flares at Petroleum Refineries when adopted in July of 2005.

Prevention Measures

The cost effectiveness analysis for Regulation 12, Rule 12 was estimated for two scenarios selected to represent the range of options among prevention measures. The first estimate, representing a costly prevention measure, considered an example of a refinery that had performed a hazard analysis for Contra Costa County and had upgraded the flare gas recovery system. A less costly prevention measure was also considered where startup and shutdown schedule adjustments resulted in a reduction of flaring, which included cost of lost production. The costs of these prevention measures were estimated to vary from $1,603 to $1,527 per ton of all pollutants for the first year and from $800 to $1500 per ton thereafter.

Currently, Regulation 12, Rule 12 requires the prevention measures developed for the lower-volume events to be included in the FMPs following inclusion in an annual report. While the proposed amendments may result in earlier implementation of one or more prevention measures, the costs of those measures would not exceed those identified when Regulation 12-12 was originally proposed and adopted.

Annual Reports and Updates

The proposed administrative amendments merely change the scheduling of the analysis and reporting of lower-volume flaring. Under the current rule, all flaring with sulfur dioxide emissions in excess of 500 pounds per day per day is addressed in a report to be submitted 12 months after approval of the initial FMP and annually thereafter. As amended, these events will have to be analyzed in a report submitted within 60 days following the end of the month in which the flaring occurs, consistent with the high volume events. Although, as discussed above, there may be more causal analyses required in the first year (or two) under the program, and prevention measures associated with these events may be scheduled for implementation earlier, the costs will not exceed the costs estimated for implementation of the current rule. Refineries will not, however, incur the costs of preparing the annual report.

C. Socioeconomic Impacts

Section 40728.5 of the Health and Safety Code requires an air district to assess the socioeconomic impacts of the adoption, amendment, or repeal of a rule if the rule is one that “will significantly affect air quality or emissions limitations.” Applied Economic Development of Berkeley, California, prepared a socioeconomic analysis for the initial proposed Regulation 12, Rule 12: Flares at Petroleum Refineries. The analysis concludes that the affected refineries should be able to absorb the costs of compliance with the proposed rule without significant economic dislocation or loss of jobs.

The proposed amendments are administrative changes; they expedite reporting of lower-volume events so that any prevention measures specifically developed for this type of flaring can be incorporated into the initial FMP. The affect on air quality and emissions will result from the various measures refineries put into place to reduce flaring, not from these administrative requirements. In any event, the proposed amendments would not change the conclusion of the socioeconomic analysis for the initial proposed Regulation 12, Rule 12: Flares at Petroleum Refineries.

D. District Staff Impacts

In the staff report for the adopted Regulation 12-12, staff identified that it will take a total of 1.5 FTE at an average staff level of a Senior Engineer to implement the rule. The total cost was estimated to exceed $250,000. The proposed amendments do not add significantly to staff impacts, and in some cases may reduce those impacts. By specifying that the refinery must provide the volume of vent gas and calculated emission data, staff resources necessary to perform the calculations from raw data will not be needed. In addition, staff time will no longer be required to review annual reports.

VI. ENVIRONMENTAL IMPACTS

Pursuant to the California Environmental Quality Act, the District prepared an Initial Study during the development of the original flare control rule (Regulation 12, Rule 12) to determine whether it would result in any significant environmental impacts. The study and subsequent Environmental Impact Report discussed certain potential significant environmental impacts, but ultimately concluded that the proposed rule would not have any significant adverse environmental impacts. Based on this determination (and others), the District adopted the flare control rule in July of 2005.

The amendments now proposed are administrative changes to the original flare control rule; they expedite reporting and development of prevention measures and incorporation of lower-volume events into the initial FMP. The District has determined that there is no possibility the proposed amendments could cause any significant environmental effect; therefore, they are exempt from the provisions of CEQA in accordance with State CEQA Guidelines section 15061(b)(3). In fact, the amendments would not constitute a “project” under CEQA because they do not have the potential to result in either a direct physical change in the environment or a reasonably foreseeable indirect physical change in the environment. (Public Resource Code section 21065; State CEQA Guidelines section 15378.)

VII. REGULATORY IMPACTS

Section 40727.2 of the Health and Safety Code requires an air district, in adopting, amending, or repealing an air district regulation, to identify existing federal and district air pollution control requirements for the equipment or source type affected by the proposed change in district rules. The district must then note any differences between these existing requirements and the requirements imposed by the proposed change. Table 2 is a matrix of the thresholds and reporting requirements, including the responsible agency.

Table 2. Reporting Thresholds and Requirements

Agency	Regulation	Requirement	Threshold	Responsible Agency
BAAQMD	Reg. 12-12	Causal Analysis	> 500,000 scfd	BAAQMD
EPA	Emergency Planning and Community Right-to-Know Act (EPCRA) and Section 112(r) of the Clean Air Act	Notification to Local Emergency Response Committee/Agency	500 lbs SO_2 100 lbs Hydrogen Sulfide	Local Emergency Response Committee/Agency
BAAQMD	Reg. 12-12 Proposed Amendments	Causal Analysis	Any flaring greater than 500 lbs/day of SO_2	BAAQMD

Federal Requirements

Federal Title 3 requirements include reporting and planning provisions at specified thresholds. The focus of these requirements is emergency response and community right to know. Adequate release response plans and timely notification to responsible agencies are required.

EPA has entered into consent decrees with all Bay Area refineries. These decrees, among other requirements, contain increments of progress for the application of New Source Performance Standards (NSPS) to all flares. NSPS limit sulfur oxides in vent gases combusted in a flare installed after June 11, 1973 (40 CFR Part 60, Subpart J, Section 60.104). Flaring caused by upset gases or fuel gas from relief valve leakage or other emergency malfunctions is exempt from the standard.

VIII. RULE DEVELOPMENT PROCESS

A. Introduction

Staff posted a request for comments on the proposed amendments to Regulation 12-12 on December 23, 2005. Three written comments were received in support of the proposed amendments.

As part of the development of the original regulation staff had undertaken an extensive rule development process in order to receive input from all affected parties. These efforts included the formation of a technical working group, public meetings, workshops and presentations to the District Board of Directors Stationary Source Committee. This process is described in the staff report for Regulation 12, Rule 12: Flares at Petroleum Refineries.

Staff has formed an implementation team to ensure thorough review of and compliance with the causal analyses and prevention measures submitted to the District by each facility. The team consists of District staff from the Engineering, Enforcement, Planning and Legal Divisions. The team meets regularly to evaluate submittals and make recommendations, which have been incorporated into the proposed amendments. In addition, the team meets with refinery staff as questions and the need for clarification and consistency arise.

B. Stationary Source Committee Reports

At the flare control rule adoption hearing on July 20, 2005, staff was directed to provide an update to the Stationary Source Committee on the cumulative impacts of a lower threshold for causal analysis. The minutes of that meeting can be found at on the District's web site at the following address, (http://www.baaqmd.gov/brd/brddirectors/agendas_minutes.htm).

Staff has reported to the Stationary Source Committee at each meeting since rule adoption. At the meeting of November 28, 2005 the Committee recommended consideration of amendments to include a causal analysis of lower-volume flaring where 500 pounds per day of SO_2 is emitted on the same schedule as for events involving flaring of vent gas at flow rates in excess of 500,000 scfd. The agenda of that meeting can be found on the District's web site at the same address.

C. Public Comment

The proposed rule amendments were made available for public comment and posted on the District's web site. Two comments expressed concern over proposed language in the definition of a reportable flaring event. The proposed language, which was intended to define the end of a reportable flaring event by specifying a volume of vent gas as the endpoint, was deemed confusing. As suggested, it has been deleted. The definition as proposed identifies the end of an event as either a specified rate or when water seal integrity is established and explains that for certain systems where more than one flare may burn vent gas, the total volume is calculated on a cumulative basis.

IX. CONCLUSION

The proposed amendments to Regulation 12, Rule 12: Flares at Petroleum Refineries, are intended to ensure that information about lower-volume flaring where sulfur dioxide emissions are greater than 500 pounds per day is available for inclusion in the initial Flare Minimization Plans. Pursuant to Health and Safety Code Section 40727, new regulations must meet standards of necessity, authority, clarity, consistency, non-duplicity and reference. The proposed amended regulation is:

- Necessary to protect public health by reducing ozone precursor emissions, and to reduce exposures to toxic air contaminants, sulfur dioxide and particulate matter by insuring that feasible prevention measures to reduce or avoid use of flares at petroleum refineries are identified and scheduled for implementation on an expedited schedule;
- Authorized by California Health and Safety Code section 40702;
- Clear, in that the new regulation specifically delineates the affected industry, compliance options and administrative requirements for industry subject to this rule;
- Consistent with other District rules, and not in conflict with State or federal law;
- Non-duplicative of other statutes, rules or regulations; and
- The proposed regulation properly references the applicable District rules and test methods and does not reference other existing law.

The proposed amendments are not subject to CEQA because they do not constitute a "project" as defined in State law and the CEQA Guidelines and because it can be determined with certainty that the amendments have no possibility of causing any significant environmental effects.

The proposed amendments will not increase the costs of implementing Regulation 12, Rule 12: Flares at Petroleum Refineries. Staff has analyzed the cost of the additional causal analysis and found them to be within the total number of analysis projected in the original adoption of Regulation 12, Rule 12 and the potential for early implementation of one or more prevention measures would not increase the costs estimated for the adoption of the current rule.

Staff recommends the adoption of the proposed amendments to Regulation 12: Miscellaneous Standards of Performance, Rule 12: Flares at Petroleum Refineries, and approval of the filing of a CEQA Notice of Exemption.

U.S. CHEMICAL SAFETY AND HAZARD INVESTIGATION BOARD

INTERIM INVESTIGATION REPORT

CHEVRON RICHMOND REFINERY FIRE

CHEVRON RICHMOND REFINERY

RICHMOND, CALIFORNIA

AUGUST 6, 2012

KEY ISSUES

- INHERENTLY SAFER DESIGN
- DAMAGE MECHANISM HAZARD REVIEW
- EFFECTIVE ANALYSIS OF PROCESS SAFEGUARDS IN PROCESS HAZARD ANALYSIS

Summary

On August 6, 2012, the Chevron U.S.A. Inc. Refinery in Richmond, California, experienced a catastrophic pipe failure in the #4 Crude Unit. The pipe ruptured, releasing flammable, hydrocarbon process fluid which partially vaporized into a large vapor cloud that engulfed nineteen Chevron employees. All of the employees escaped, narrowly avoiding serious injury. The flammable portion of the vapor cloud ignited just over two minutes after the pipe ruptured. The ignition and subsequent continued burning of the hydrocarbon process fluid resulted in a large plume of unknown and unquantified particulates and vapor traveling across the Richmond, California, area. In the weeks following the incident, approximately 15,000 people from the surrounding area sought medical treatment due to the release. Testing commissioned by the U.S. Chemical Safety and Hazard Investigation Board (CSB) and the California Division of Occupational Safety and Health (Cal/OSHA) determined that the pipe failed due to thinning caused by sulfidation corrosion, a common damage mechanism in refineries. As a result of the incident, the Chevron Richmond Refinery crude unit remains out of commission over eight months later. In addition, Cal/OSHA issued the refinery 17 citations related to the incident and eight additional citations, with a total proposed fine of nearly one million dollars. In this interim report, the CSB is issuing recommendations to Chevron, the City of Richmond, Contra Costa County, Cal/OSHA, the State of California, and the U.S. Environmental Protection Agency, addressing the need for inherently safer design, rigorous and documented damage mechanism hazard reviews, and thorough analyses of process safeguards.

This interim investigation report contains detailed analyses of and makes recommendations to Chevron and regulatory bodies at the local, state, and federal level. The CSB believes the findings and recommendations presented in this report can be applied to refineries, chemical plants, and other industries nationwide to improve process safety.

The CSB plans to release a comprehensive Final Investigation Report later in 2013 that will include analyses and recommendations relating to technical and regulatory investigation findings which are not included in this interim report. The Final Investigation Report will cover topics including: the importance of having a competent, well-funded regulator and an adaptable regulatory regime; Chevron safety culture; process safety indicator data collection and reporting; emergency planning and response; stop work authority; and recommendations for improvement of petroleum industry standards and recommended practices. Some of these issues are previewed at the end of this interim report under *Additional Issues Currently Under Investigation*.

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Figures

Acronyms and Abbreviations

ALARP	As Low As Reasonably Practicable
API	American Petroleum Institute
ASTM	American Society for Testing and Materials
BIN	Business Improvement Network
bpd	Barrels Per Day
BPTC	BP Texas City
CAA	Clean Air Act
Cal/OSHA	California Division of Occupational Safety and Health
CCPS	Center for Chemical Process Safety
CCR	California Code of Regulations
Chevron ETC	Chevron Energy Technology Company
CML	Condition Monitoring Locations
CSB	U.S. Chemical Safety and Hazard Investigation Board
CSHO	Compliance Safety and Health Officer
CWS	Community Warning System
EPA	Environmental Protection Agency
°F	degree Fahrenheit
HSE	Health and Safety Executive
ISO	Industrial Safety Ordinance
ISS	Inherently Safer Systems
IST	Inherently Safer Technology
KPI	Key Process Indicator

LEPC	Local Emergency Planning Committee
LOPA	Layers of Protection Analysis
MOC	Management of Change
NEP	National Emphasis Program
OEM	U.S. EPA Office of Emergency Management
OSHA	Occupational Safety and Health Administration
P&P	Policy and Procedures
PHA	Process Hazard Analysis
PMI	Positive Materials Identification
psig	Pounds Per Square Inch Gauge
PSM	Process Safety Management
RISO	City of Richmond Industrial Safety Ordinance
RLOP	Richmond Lube Oil Project
RMP	Risk Management Plan
SIP	Shelter-In-Place
TML	Thickness Monitoring Location
UK	United Kingdom
USW	United Steelworker International Union
wt. %	Weight Percent

Background and Findings

1. On August 6, 2012, the Chevron U.S.A. Inc. Refinery in Richmond, California (Chevron Richmond Refinery), experienced a catastrophic pipe rupture in the #4 Crude Unit (crude unit). The ruptured pipe released a flammable hydrocarbon process fluid which then partially vaporized into a large vapor cloud that engulfed nineteen Chevron U.S.A. Inc. (Chevron) employees. At 6:33 pm, approximately two minutes after the release, the flammable portion of the vapor cloud ignited.[i] Eighteen of the employees safely escaped from the cloud just before ignition; one employee, a firefighter, was inside a fire engine that caught fire when the vapor cloud ignited (Figure 1). Because he was wearing full body fire-fighting protective equipment, he was able to make his way to safety. Six Chevron employees suffered minor injuries during the incident and subsequent emergency response efforts.

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[i] Surveillance footage provided by Chevron. Chevron clarified to CSB that video time is approximately 5 minutes out of sync. The video can be found at http://www.csb.gov/videoroom/detail.aspx?VID=69 (accessed February 8, 2013).

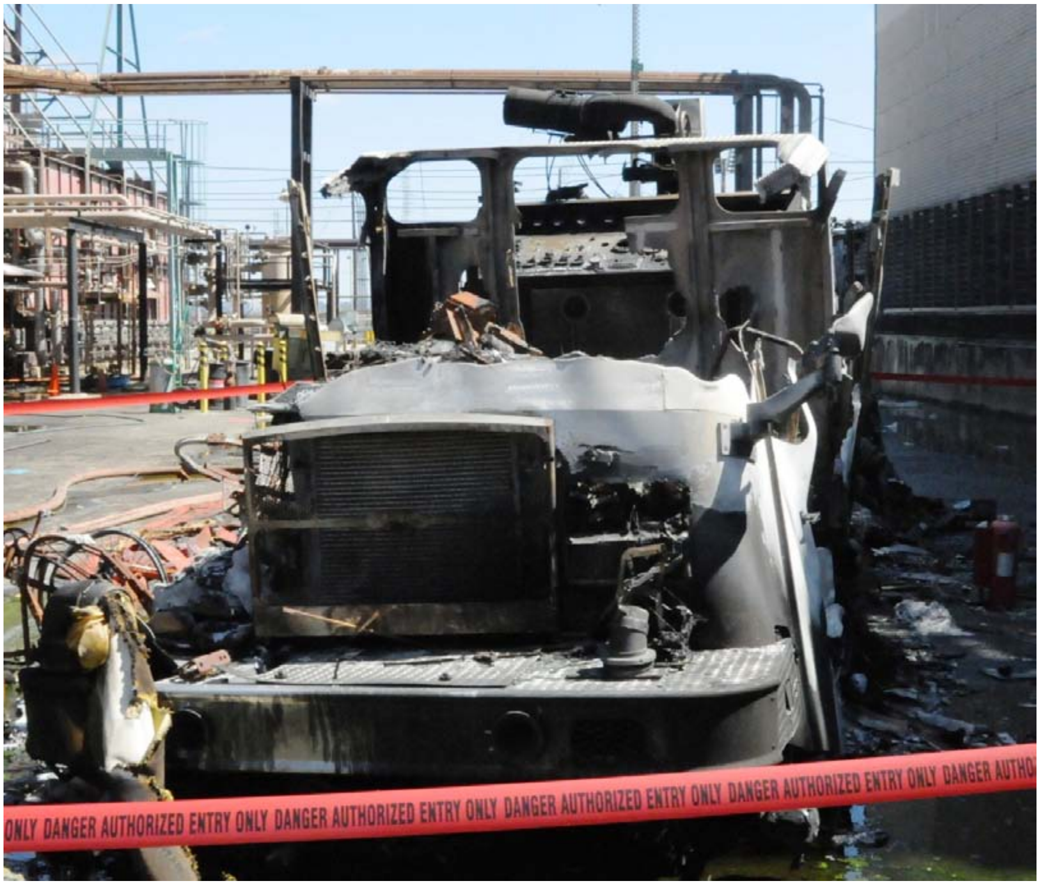

Figure 1. The burned remains of the fire truck that was consumed by the fire. A firefighter was in the cab when the vapor cloud ignited. The fire truck was positioned approximately 65 feet from the leak location.

2. The ignition and subsequent continued burning of the hydrocarbon process fluid resulted in a large plume of unknown and unquantified particulates and vapor traveling across the Richmond, California, area (Figures 2 and 3). This resulted in a Community Warning System (CWS) Level 3 alert,[i] and a shelter-in-place[ii] (SIP) was issued at 6:38 pm[1] for the cities of Richmond, San Pablo, and North Richmond. It was lifted later that night at 11:12 pm after the fire was fully under control. In the weeks following the incident, nearby medical facilities received over 15,000 members of the public seeking treatment for ailments including breathing problems, chest pain, shortness of breath, sore throat, and headaches. Approximately 20 people were admitted to local hospitals as inpatients for treatment.

Figure 2. Vapor cloud (white) over Richmond area and smoke (black) from Chevron Richmond Refinery fire as seen from San Rafael in Marin County.[2]

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[i] A Community Warning System Level 3 alert indicates that a facility within Contra Costa County has had a release that has offsite impact and is categorized by any of the following:

1. Off-site impact that may cause eye, skin, nose and/or respiratory irritation to the general population.
2. Fire, explosion, heat, or smoke with an off-site impact. Example: On a process unit/storage tank where mutual aid is requested to mitigate the event and the fire will last longer than 15 minutes.
3. Hazardous material or fire incident where the incident commander or unified command, through consultation with the Contra Costa Health Services Hazardous Material Incident Response Team, requests that sirens should be sounded.

See http://cchealth.org/hazmat/pdf/incident_notification_policy.pdf (accessed April 9, 2013).

[ii] Contra Costa County considers a shelter-in-place to include going inside a home or nearest building, closing doors and windows, and turning off heating, ventilation, and air conditioning. *See* http://cchealth.org/emergencies/shelter-in-place.php (accessed February 6, 2013).

Figure 3. Initial vapor cloud formation (white cloud) and subsequent ignition (black smoke) as seen from a pier in San Francisco, California.

3. The incident occurred from the piping referred to as the “4-sidecut” stream, one of several process streams exiting the C-1100 Crude Unit Atmospheric Column (Figure 4).[i] A plot plan of the crude unit shows the leak location relative to C-1100 (Figure 5). As shown in Figure 6, light gas oil (the crude unit 4-sidecut process fluid) exits the atmospheric column via a 20-inch nozzle and is split into a 12-inch line and an 8-inch line. The August 6, 2012, pipe rupture (Figure 7) occurred on a 52-inch long component[ii] of the 4-sidecut 8-inch line (the 52-inch component). The line operated at a temperature of 640 degrees Fahrenheit (°F)[iii] and had an operating pressure of approximately 55 pounds per square inch gauge (psig) at the rupture location. At the

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[i] The atmospheric column separates crude oil feed into different streams through distillation. These streams are further processed in other units in the refinery.

[ii] The term “component” refers to a portion of piping between welds or flanges. It includes straight run piping and pipe fittings.

[iii] The auto-ignition temperature for this process, the temperature at which a material will combust in the presence of sufficient oxygen without an ignition source, was also 640 °F. This number is based on the Chevron Light Gas Oil Material Safety Data Sheet. Chemical testing of 4-sidecut samples following the incident indicated lower auto-ignition temperatures; however, these samples may not have been representative of typical 4-sidecut process fluid.

time of the incident, light gas oil was flowing through the 8-inch line at a rate of approximately 10,800 barrels per day (bpd).[i]

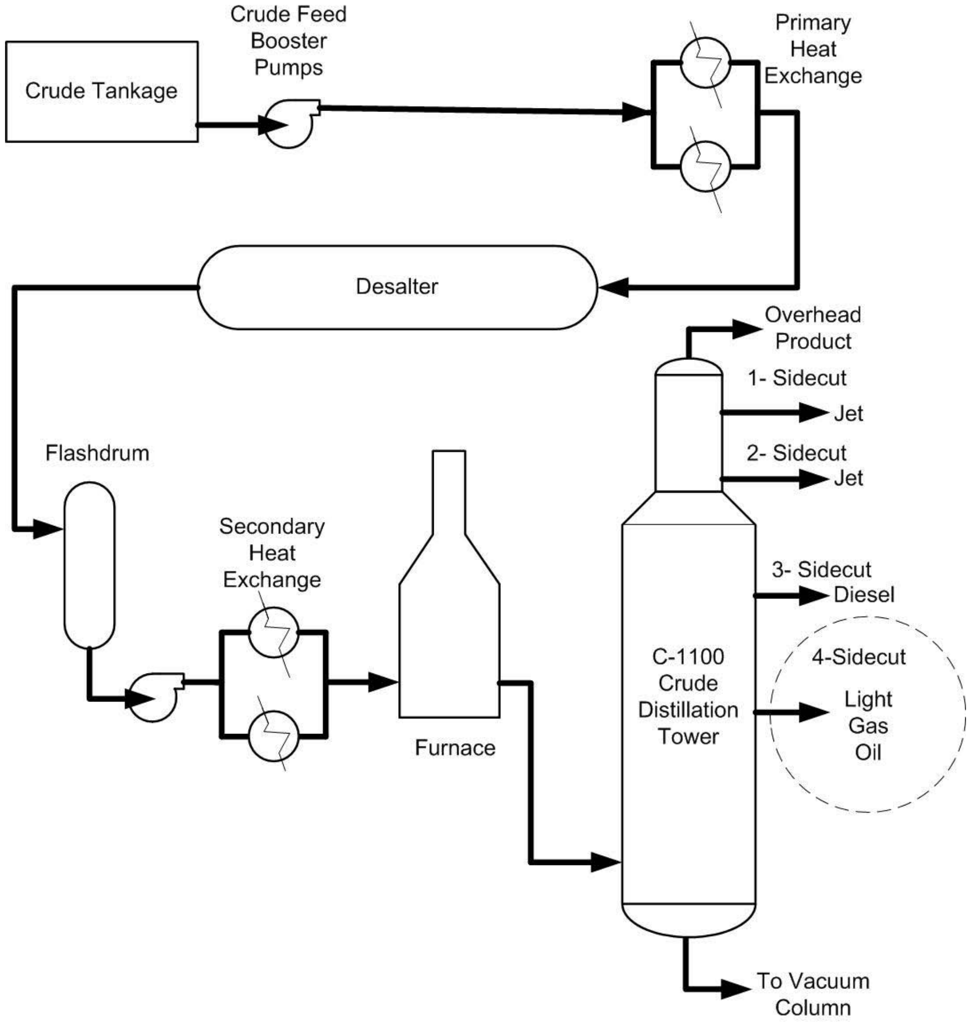

Figure 4. C-1100 Crude Unit Atmospheric Column and Upstream Process Equipment.

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[i] This is the equivalent of 315 gallons per minute (gpm). A barrel equals 42 gallons.

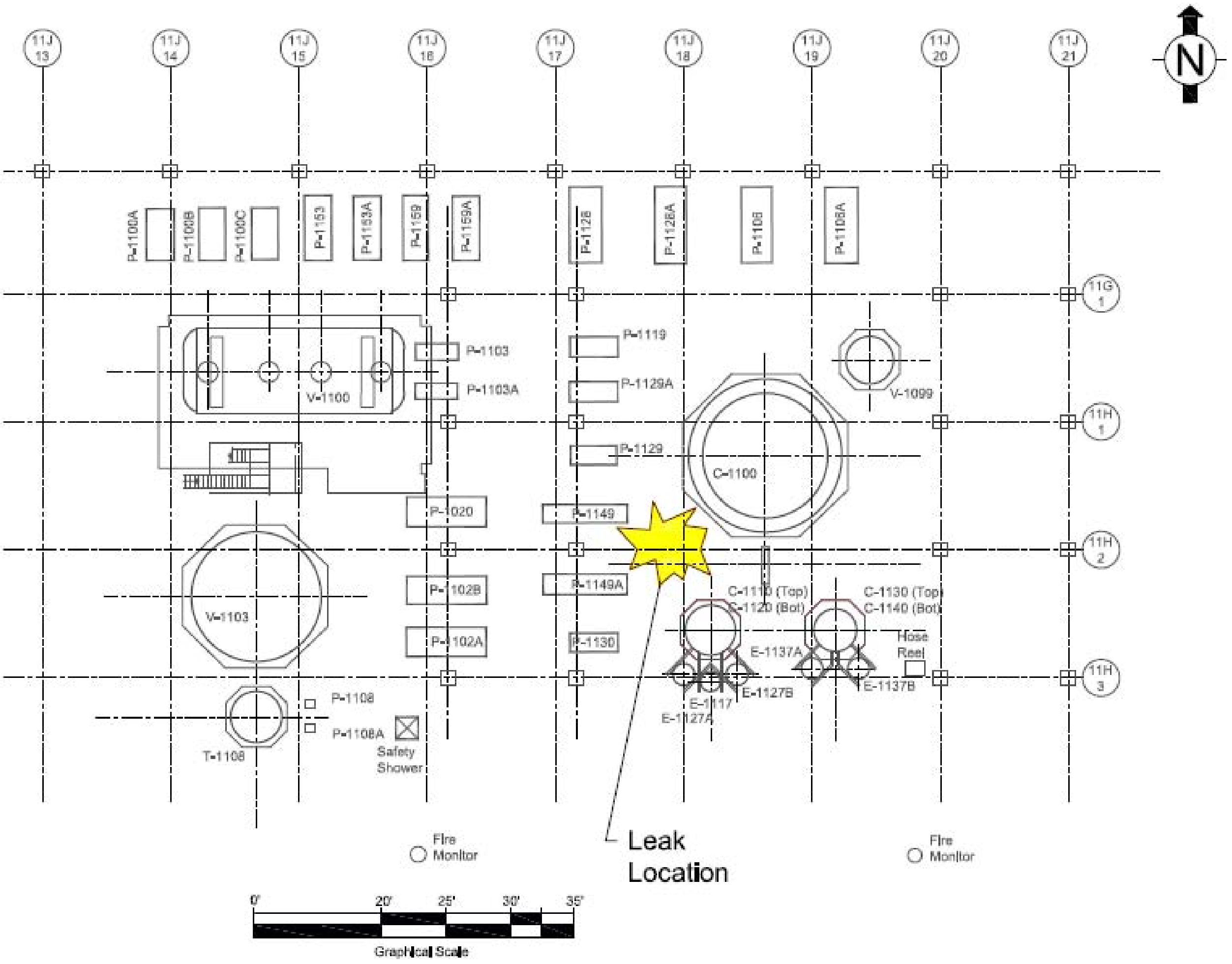

Figure 5. Overhead view of the equipment in the #4 Crude Unit showing the leak location, commonly referred to as a plot plan.

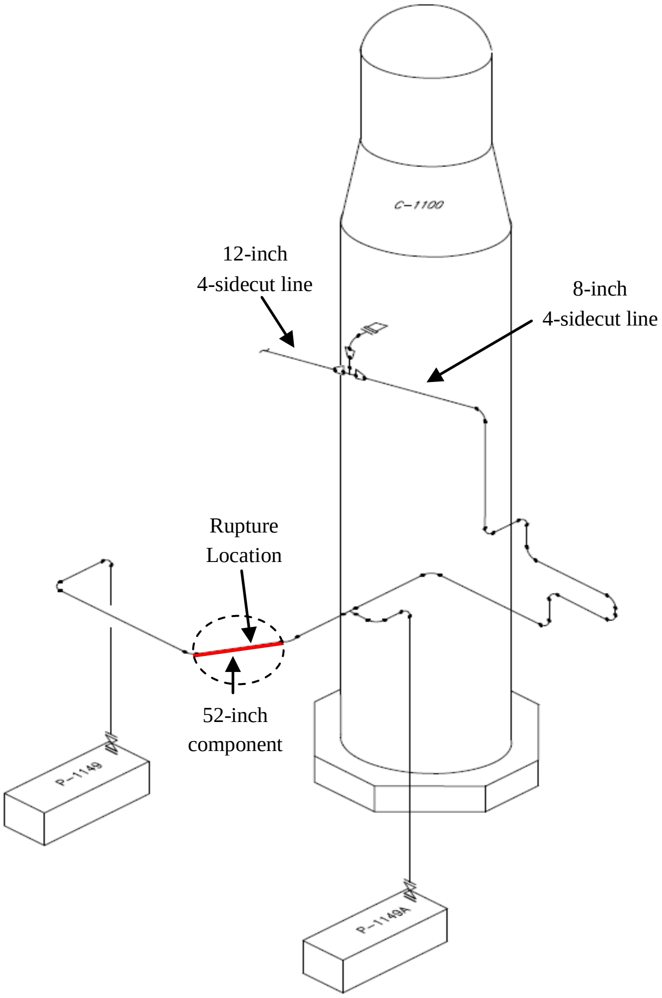

Figure 6. 4-sidecut line configuration and rupture location.

4. The CSB commissioned Anamet, Inc., a materials engineering and laboratory testing company, to conduct testing of the 4-sidecut pipe, including the failed 52-inch component. The testing concluded that the rupture was due to pipe wall thinning caused by sulfidation corrosion,[3] which is discussed below.

5. Anamet's metallurgical analysis found that the 52-inch component where the rupture occurred had experienced extreme thinning; the average wall thickness near the rupture location was approximately 40 percent thinner than a dime[i] (the thinnest American coin). Between 1976 and 2012, the 52-inch piping component had lost, on average, 90 percent of its original wall thickness in the area near the rupture. The piping had an initial nominal wall thickness of 0.322-inch[ii] when it was installed in 1976.

Figure 7. Photo of rupture on 4-sidecut 52-inch component.

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[i] The U.S. Mint reports that a dime has a thickness of 1.35 mm, or 0.053 inches. Information can be found at http://www.usmint.gov/about_the_mint/?action=coin_specifications (accessed February 14, 2013).

[ii] This portion of the 4-sidecut line was constructed of 8-inch Schedule 40 carbon steel piping.

Sulfidation Corrosion

6. Sulfidation corrosion is a damage mechanism[i] that is well understood in the refining industry. The sulfidation corrosion industry guidance document, American Petroleum Institute (API) Recommended Practice (RP) 939-C *Guidelines for Avoiding Sulfidation (Sulfidic) Corrosion Failures in Oil Refineries*[ii] notes:

> [Sulfidation] …is not a new phenomenon, but was first observed in the late 1800s in a pipe still (crude separation) unit, due to the naturally occurring sulfur compounds found in crude oil. When heated for separation, the various fractions in the crude were found to contain sulfur compounds that corroded the steel equipment.[4]

7. Sulfidation corrosion, also known as sulfidic corrosion,[5] is a damage mechanism that causes thinning in iron-containing materials, such as steel, due to the reaction between sulfur compounds and iron at temperatures ranging from 450 °F to 800 °F.[6] This damage mechanism causes pipe walls to gradually thin over time. Sulfidation corrosion is common in crude oil distillation[iii] where naturally occurring sulfur and sulfur compounds found in crude oil feed, such as hydrogen sulfide,[iv] are available to react with steel piping and equipment. Process variables that affect corrosion rates include the total sulfur content of the oil, the sulfur species present, flow conditions, and the temperature of the system. Virtually all crude oil feeds contain sulfur compounds and, as a result, sulfidation corrosion is a damage mechanism present at every refinery that processes crude oil. Sulfidation corrosion can cause thinning to the point of pipe failure when not properly monitored and controlled.

8. The reaction between sulfur and iron produces a layer of iron sulfide scale[v] on the inside surface of piping.[7] This reaction can be compared to that of oxygen and iron which also produces a scale, commonly known as rust. The type of scale formed by sulfidation corrosion is dependent upon the components contained in the steel. Certain scales formed are protective and actually reduce the reaction rate between sulfur compounds and iron, minimizing sulfidation corrosion

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[i] Piping damage mechanisms are any type of deterioration encountered in the refining and chemical process industry that can result in flaws/defects that can affect the integrity of piping (e.g. corrosion, cracking, erosion, dents, and other mechanical, physical or chemical impacts). *See* API 570. "Piping Inspection Code: In-Service Inspection, Rating, Repair, and Alteration of Piping Systems." 3rd ed., Section 3.1.1.5, November 2009.

[ii] API RP 939-C is one of several relevant American Petroleum Institute recommended practices and standards under evaluation by the CSB as part of this investigation. To the casual observer API RP 939-C appears to obligate the industry to take significant actions. However, the CSB concluded it was written to be permissive so that industry compliance with specific provisions would not be required. The complete findings from this evaluation will be included in the CSB's Final Report.

[iii] Distillation separates mixtures into broad categories of its components by heating the mixture in a distillation column where different products boil off and are recovered at different temperatures. *See* http://www.eia.gov/todayinenergy/detail.cfm?id=6970 (accessed April 4, 2013).

[iv] Hydrogen sulfide is the most aggressive sulfur compound that causes sulfidation corrosion.

[v] Scale is a nonmetallic layer on the surface of metals and is often a result of corrosion.

rates. For instance, sulfidation corrosion affecting steel alloys containing greater than two weight percent (wt. %) chromium produces a protective scale that inhibits the reaction between the iron and sulfur compounds, thereby reducing corrosion rates.[i] With increasing percentages of chromium, the reaction is further slowed, greatly diminishing corrosion rates.[8,ii] For example, stainless steel (an 18 wt. % chromium alloy) is nearly 15 times more resistant to sulfidation corrosion than 9-Chrome (a 9 wt. % chromium alloy).[9] Conversely, sulfidation corrosion rates are significantly higher in steels containing very little chromium. Carbon steel, the Chevron 4-sidecut line material of construction, was manufactured with a maximum concentration of 0.40 % chromium.[10] The scale formed on carbon steel is less protective and allows continued reaction between the sulfur compounds and iron.[11] Thus, carbon steel corrodes at a rate that is significantly faster than other materials of construction, such as high chromium steels.

9. In addition to its inherently faster rate of sulfidation corrosion when compared with higher chromium steels, carbon steel also experiences significant variation in corrosion rates due to variances in silicon content, a component used in the steel manufacturing process. Carbon steel piping containing silicon content less than 0.10 wt. % can corrode at accelerated rates,[12] up to sixteen times faster than carbon steel piping containing higher percentages of silicon as shown in Figure 8. This figure shows how carbon steel corrosion rates can greatly vary depending on silicon content.

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[i] At greater than two wt. % chromium, sulfur compounds react with the steel to form $FeCr_2S_4$ scale. This scale provides more protection than the FeS scale that forms on carbon steel piping. *See* Niccolls, E. H., J. M. Stankiewicz, J. E. McLaughlin, and K. Yamamoto. "High Temperature Sulfidation Corrosion in Refining." *17th International Corrosion Congress.* Las Vegas: NACE International, 2008.

[ii] It has also been found that chromium “poisons” the decomposition of sulfur compounds to hydrogen sulfide which also slows down the sulfidation corrosion rate. *See* Couper, A.S. “High Temperature Mercaptan Corrosion of Steels.” *19th Annual Conference of the National Association of Corrosion Engineers*. Pages 396t-401t, New York: March 1963.

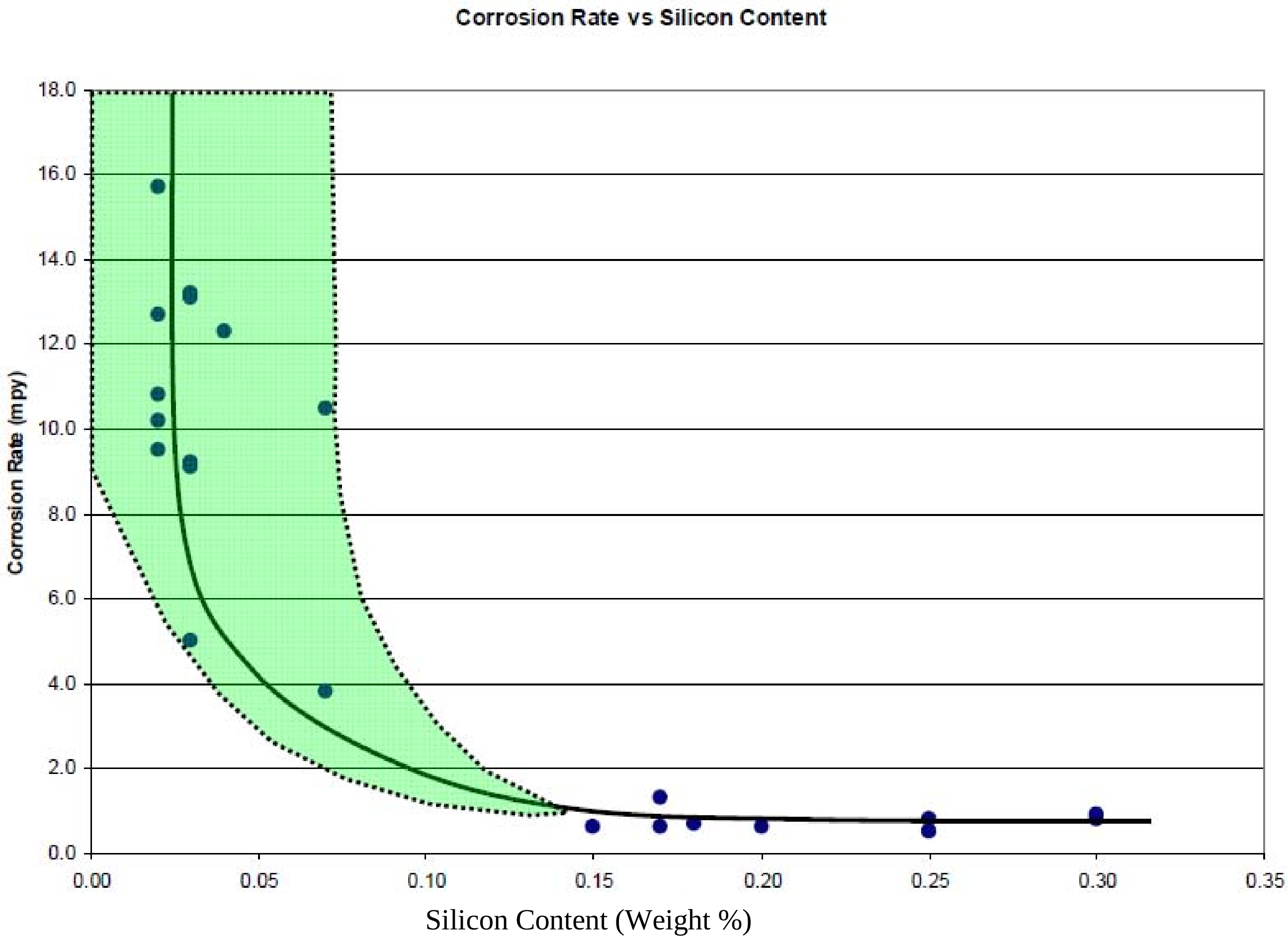

Figure 8. This graph shows how corrosion rates increase in carbon steel containing decreasing percentages of silicon. This information can be found in Annex C of API RP 939-C.[i]

10. The refining industry has been aware of increased rates of sulfidation corrosion in low-silicon carbon steel piping since as early as 1974,[13] nearly 40 years before the August 6, 2012, incident and two years before the Chevron crude unit was constructed. Prior to the incident, Chevron documented its understanding of the significant consequences of sulfidation corrosion. This is reflected in Chevron's *Corrosion Prevention and Metallurgy Manual*, which states:

> Sulfidation corrosion has caused severe fires and fatalities in the refining industry, primarily because it causes corrosion over a relatively large area, so failures tend to involve ruptures or large leaks rather than pinhole leaks. It can be insidious in that moderately high corrosion rates can go undetected for years before failure. Finally, process changes that increase the temperature or sulfur content can creep up over time and

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[i] The y-axis of this figure is in units of mils per year (mpy). A "mil" is 1/1000 inch.

> multiply corrosion rates so that what was thought to be a low corrosion rate system becomes corrosive enough to fail before the increased corrosion rate is recognized.

11. Carbon steel piping is manufactured to meet certain specifications, including American Society for Testing and Materials (ASTM) A53B,[14] ASTM A106,[15] and API 5L.[16] ASTM A53B and API 5L do not contain minimum silicon content requirements for carbon steel piping,[17] while ASTM A106 requires the piping to be manufactured with a minimum silicon content of 0.10 wt. %. As a result, manufacturers have used different levels of silicon in the carbon steel pipe manufacturing process. Thus, depending on the manufacturing specification for carbon steel susceptible to sulfidation corrosion, corrosion rates could vary depending on the silicon content within the steel.

12. In the mid 1980s, pipe manufacturers began to simultaneously comply with all three manufacturing specifications (ASTM A53B, ASTM A106, and API 5L) when manufacturing carbon steel piping. The majority of carbon steel piping purchased following this time period likely has a minimum of 0.10 wt. % silicon content. However, piping purchased and installed prior to the mid-1980s could still contain low silicon components that are susceptible to high, variable sulfidation corrosion rates.

13. Over 95 percent of the 144 refineries in operation in the U.S., including the Chevron Richmond Refinery,[i] were built before 1985,[18] and thus before piping manufacturers began producing carbon steel in compliance with all three manufacturing specifications. Therefore, the original carbon steel piping in these refineries is likely to contain varying percentages of silicon content and may experience highly variable sulfidation corrosion rates.

14. The Chevron Richmond Refinery 4-sidecut piping circuit containing the 52-inch component that failed was constructed of ASTM A53B carbon steel, which had no minimum specification for silicon content. Post-incident testing of samples of the 4-sidecut piping from the Chevron Richmond Refinery identified silicon content ranging from 0.01 wt. % to 0.2 wt. %. Of twelve samples taken from the 8-inch and 12-inch 4-sidecut line, six had a silicon concentration of less than 0.10 wt. %. The 52-inch pipe component that ruptured on the day of the incident had a silicon content of only 0.01 wt. %. The elbow component directly upstream of the 52-inch component that failed had a silicon concentration of 0.16 wt. % and showed considerably less thinning (Figure 9).

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[i] The Chevron Richmond Refinery was constructed in 1902.

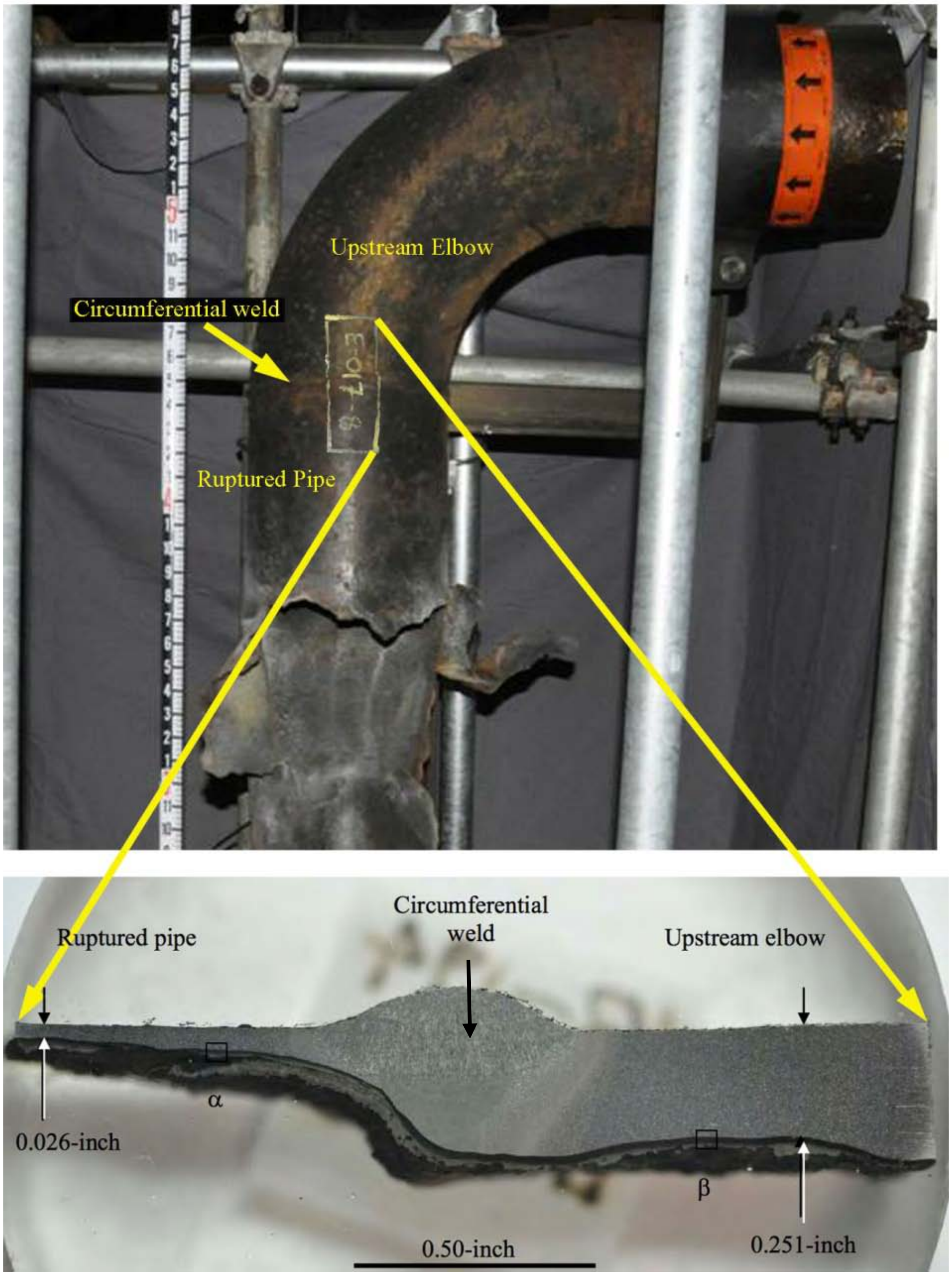

Figure 9. 4-sidecut piping sample (E-017-8) analyzed by Anamet Labs showing the relative thickness of low silicon piping on the left and the high silicon piping on the right. The ruptured pipe component (left) contained 0.01 % silicon and the upstream elbow component (right) contained 0.16 % silicon.[19] The initial nominal thickness of this piping was 0.322-inch.

Sulfidation Corrosion Inspection Techniques

15. As evidenced by the chemical analysis performed on the Chevron 4-sidecut piping post-incident, carbon steel piping components within a single circuit[i] can contain varying percentages of silicon, resulting in a large variation in sulfidation corrosion rates by component. Historically, sulfidation corrosion monitoring techniques required the measurement of pipe thickness at only a minimal number of permanent Condition Monitoring Locations (CMLs)[ii] along the piping. These CMLs are most frequently placed on elbows and fittings.[iii] However, due to details of the manufacturing process, carbon steel pipe fittings generally contain high percentages of silicon.[20] When measurements are only taken at high-silicon containing fittings, the measurements can fail to identify high corrosion rates within a pipe circuit caused by low-silicon components. At the Chevron Richmond Refinery, the 4-sidecut piping had a total of 24 CMLs[iv] on piping and fittings. The CSB found that there were no CMLs placed on the low silicon piping component that failed. Chevron identified accelerated corrosion in the 52-inch component in a 2002 inspection. However, no CML was added to ensure future monitoring, and the 52-inch component was not inspected again. Instead, the CSB found that Chevron relied on inspection data gained primarily from high silicon pipe-fitting components, such as elbow components. This inspection data did not reflect the corrosion rates of the lower-silicon components of the 4-sidecut piping. Relying on the limited inspection data from the CMLs on the high silicon components, Chevron management denied multiple recommendations to replace the 4-sidecut line. As illustrated by the Chevron incident, inspection techniques alone may not accurately identify the most aggressive corrosion rates throughout an entire circuit of carbon steel piping. Low-silicon components can remain uninspected and unidentified until failures such as the August 6, 2012, Chevron incident occur. As will be discussed below, upgrading metallurgy is a more effective means of managing sulfidation corrosion.

16. Determining silicon content in existing carbon steel piping and equipment in the field is a difficult undertaking. To properly characterize the silicon content in each component in a piping circuit, every component must be inspected. This is known as 100 percent component inspection. Two techniques are currently used to determine silicon content in existing carbon steel piping circuits with unknown chemical composition: performing chemical analysis and pipe wall thickness measurements of every component.

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[i] A piping circuit is a length of pipe and the fittings associated with a particular process service that operate at similar conditions. A circuit usually begins and ends at either a branch or a piece of process equipment such as a vessel or a pump. Reference to piping by circuits allows piping to be grouped conveniently by proximity and operating service. Piping circuits may also be referred to as piping runs.

[ii] A condition monitoring location (CML) is a designated area where periodic thickness examinations are conducted. Each CML represents as many as four inspection locations located circumferentially around the pipe. CMLs are also referred to as thickness monitoring locations (TMLs). CML was historically referred to as corrosion monitoring locations (CMLs) and that terminology is sometimes still used within the industry.

[iii] A fitting is a piping component usually associated with a change in direction or diameter.

[iv] Many of these CMLs were added during the 2011 turnaround.

17. Many field-portable instruments used for positive material identification cannot adequately identify silicon content.[21] If original manufacturing quality assurance data[i] are not available, as is generally the case with older plants, then chemical verification requires destructive testing. Metal shavings must be taken from each carbon steel piping component for chemical analysis in a laboratory.[22] This method requires that the insulation be removed for access to the piping so that each individual piping component can be sampled and verified.

18. Carbon steel components containing low concentrations of silicon can also potentially be identified by performing thickness measurements of every component within a carbon steel circuit.[23] This practice is only useful if the piping circuit has been exposed to sulfidation corrosion for a long enough time period so that variances in corrosion rate caused by differences in silicon content may be detected. Chemical analysis is therefore the most accurate technique to identify low-silicon carbon steel components. As with chemical analysis, the thickness measurement method requires that each individual piping component be identified by removing insulation (so every weld seam can be located), a time consuming and costly undertaking, or by using non-destructive examination techniques. Thickness measurements on high temperature piping typically can only be done accurately and safely during unit turnarounds.[ii] Although these various methods were available to detect the location of the field welds, Chevron had not used them to identify the 4-sidecut pipe segment locations.

19. API Recommended Practice 939-C *Guidelines for Avoiding Sulfidation (Sulfidic) Corrosion Failures in Oil Refineries* describes the challenges faced when attempting to thoroughly inspect carbon steel lines susceptible to sulfidation corrosion. The recommended practice states that older ASTM A53 piping, such as the Chevron piping that failed on August 6th, creates a "major inspection challenge"[24] and that "unless the refinery is fortunate enough to have located an inspection point on that particular [low silicon] section of pipe or fitting, it is very difficult to detect the thinning component."[25] It states that in some applications, carbon steel will appear to be adequate based on measured corrosion rates until failure occurs at some undocumented or unidentified low-silicon component.[26]

20. Unlike silicon concentration, the chromium concentration of steel can easily be verified in the field using portable positive material identification instruments. In addition, steel alloys containing at least 9 wt. % chromium are more resistant to sulfidation corrosion and do not run the risk of extreme variations in corrosion rates within components in the same piping circuit.[iii] This makes alloys with higher chromium content an inherently safer choice in high temperature

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[i] Manufacturing quality assurance data, also known as mill data, provides the chemical composition of the steel.

[ii] A "turnaround" is a scheduled shutdown of a process unit to perform maintenance, repairs, upgrades, and inspection of process equipment.

[iii] The protective scale, $FeCr_2S_4$, begins to be the dominant scale formed in steels containing a chromium content of five wt. %. The 5Cr steel alloy can be manufactured to contain anywhere from 4% to 6% chromium. Thus, "the sulfidation corrosion rate can vary dramatically in 5Cr steels even in the same operating environment." *See* Niccolls, E. H., J. M. Stankiewicz, J. E. McLaughlin, and K. Yamamoto. "High Temperature Sulfidation Corrosion in Refining." *17th International Corrosion Congress.* Las Vegas: NACE International, 2008.

sulfidation corrosion environments.[i] As shown in the Modified McConomy Curves[ii] from API RP 939-C (Figure 10), 9-Chrome[iii] corrodes 15 times faster than stainless steel,[iv] and carbon steel[v] corrodes 125 times faster than stainless steel.[27]

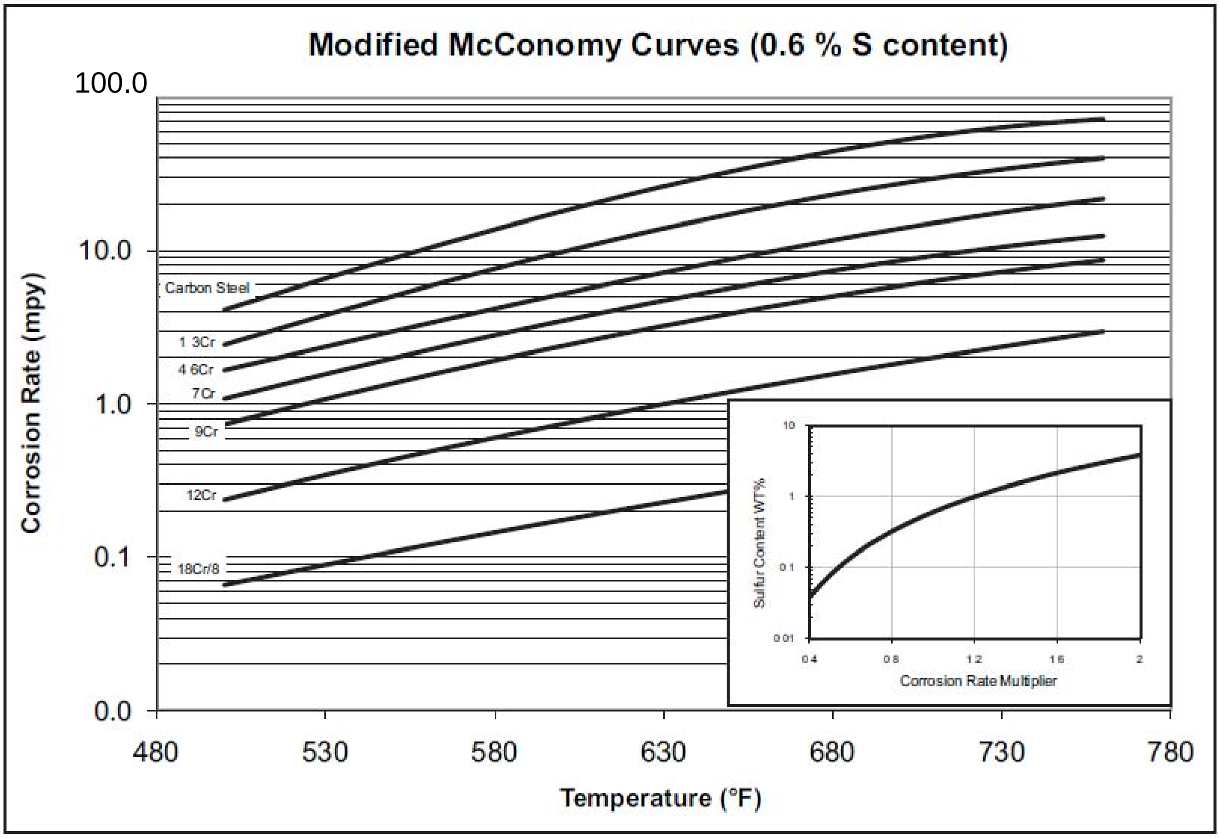

Figure 10. Modified McConomy Curves from API RP 939-C.

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[i] Steels with higher chromium content are inherently safer than carbon steel with respect to sulfidation corrosion. However, analysis is still required to ensure that the best material of construction is selected.

[ii] Modified McConomy Curves are the set of curves API RP 939-C uses to predict sulfidation corrosion rates versus temperature for several steel alloys.

[iii] 9-Chrome contains 9 wt. % chromium.

[iv] Stainless steel contains 18 wt. % chromium.

[v] ASTM A53B carbon steel contains a maximum of 0.40 wt. % chromium.

Chevron Sulfidation Corrosion Knowledge and Expertise

21. Figure 11 shows a timeline of Chevron's key sulfidation events. Chevron technical staff has considerable knowledge and expertise regarding sulfidation corrosion, specifically with respect to corrosion rate variations caused by differing silicon concentration in carbon steel piping. Chevron employees have authored industry papers on sulfidation corrosion and had significant influence in the development of the industry sulfidation corrosion recommended practice, API RP 939-C. This recommended practice, first published in 2009, was developed under Chevron leadership. At the approximate time of publication of API RP 939-C, Chevron Energy Technology Company (Chevron ETC)[i] created an internal document on the subject of sulfidation corrosion. Chevron ETC metallurgists released a formal report dated September 30, 2009 (nearly 3 years prior to the incident) to Chevron refinery-based reliability managers and chief inspectors entitled *Updated Inspection Strategies for Preventing Sulfidation Corrosion Failures in Chevron Refineries*.

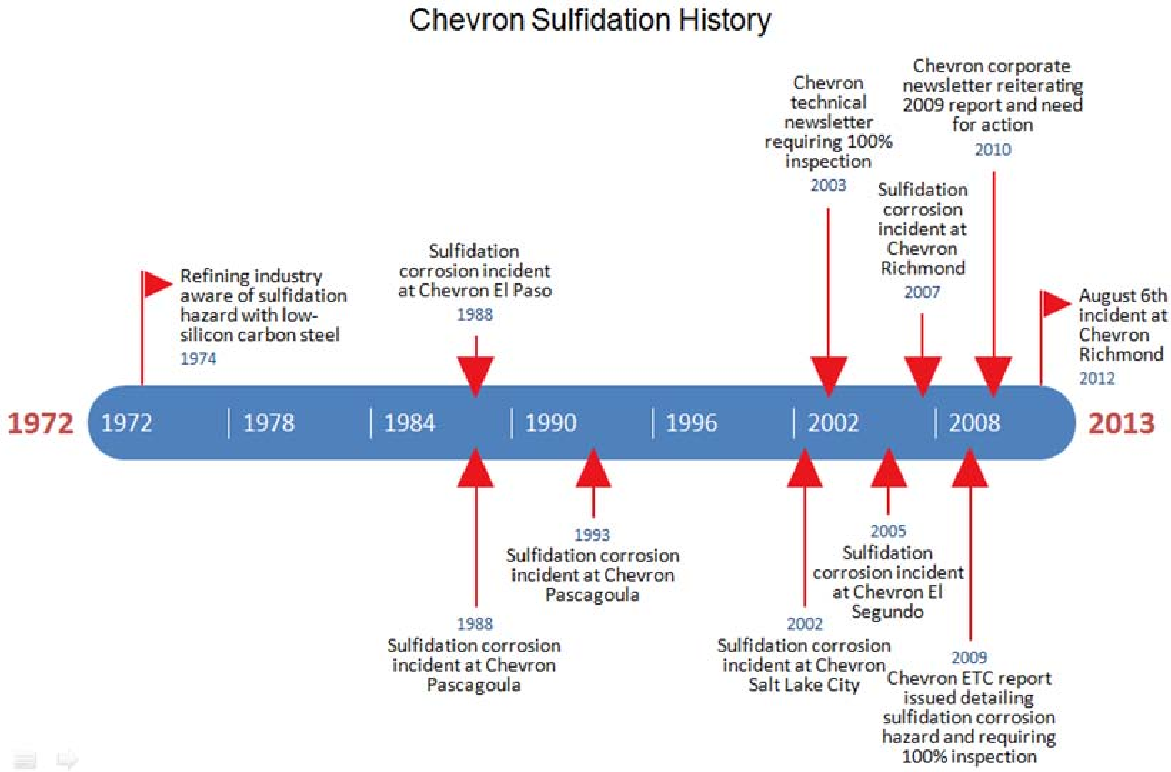

Figure 11. Chevron's key sulfidation events between 1974 and 2013.

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[i] The Chevron Energy Technology Company is a separate business unit within the Chevron Corporation that provides technology solutions and technical expertise for Chevron operations worldwide. *See* http://richmond.chevron.com/home/aboutchevronrichmond.aspx (accessed April 4, 2013)

22. Sulfidation experts acknowledged in the Chevron ETC report that, “Until now, Chevron has not directly addressed the risk of low Si[licon] carbon steel…”[i] and that the report lays out a program that “seeks to close these gaps, and to maximize the effectiveness of our inspection.” The report clearly indicates that Chevron understood both the potential consequence and the high likelihood of a rupture or catastrophic failure from sulfidation corrosion and calls out Chevron’s need for action:

> Sulfidation corrosion failures are not common in Chevron or in the industry but they are of great concern because of the comparatively high likelihood of blowout or catastrophic failure […] . This can happen because corrosion occurs at a relatively uniform rate over a broad area so a pipe can get progressively thinner until it actually bursts rather than leaking at a pit or local thin area. In addition the process fluid is often above its autoignition temperature. The combination of these factors means that sulfidation corrosion failures frequently result in large fires. […] [S]everal case histories of sulfidation corrosion failures that have occurred in Chevron or in the industry several of which are blowouts.

This Chevron ETC report specifically recommends that inspectors perform 100 percent component inspection on high temperature carbon steel piping susceptible to sulfidation corrosion. However, this 100 percent component inspection program was not implemented at the Richmond refinery prior to the August 6, 2012 incident. The Chevron ETC report defines a priority ranking system to help focus the inspection implementation efforts. The process conditions of the 4-sidecut stream placed it in the highest priority for inspection.

23. Chevron ETC technical experts issued a corporate newsletter in 2010 that again warned of the potential consequence of sulfidation failures. In this newsletter, the 100 percent component inspection recommendation from the 2009 report was reiterated for piping systems such as the crude unit 4-sidecut piping. The newsletter states:

> Sulfidation corrosion failures … are of great concern because of the comparatively high likelihood of “blowout” or catastrophic failure. This typically happens because corrosion occurs at a relatively uniform rate over a broad area, so a pipe can get progressively thinner until it actually bursts rather than leaking at a pit or local thin area. In addition, the process fluid is often above its autoignition temperature. The combination of these factors means that sulfidation corrosion failures frequently result in large fires. Chevron and the industry have experienced numerous failures from this mechanism and recent incidents have reinforced the need for revised inspection strategies and a robust PMI (Positive Materials Identification) program.

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[i] A 2003 corporate technical newsletter recommended 100 percent component inspection of carbon steel piping susceptible to sulfidation corrosion following a 2002 Chevron Salt Lake City sulfidation corrosion incident.

The Chevron ETC 100 percent component inspection recommendation for high risk piping systems, established in 2009, was not implemented at Richmond; therefore, the thin-walled low silicon 4-sidecut piping component remained in service until it catastrophically failed on August 6, 2012.

24. Chevron and Chevron ETC metallurgists, materials engineers, and piping inspectors had expertise regarding sulfidation corrosion. They educated personnel and advocated for identification and control of damage mechanisms, including sulfidation corrosion. However, they had limited practical influence to implement their recommendations. These individuals did not participate in the crude unit Process Hazard Analysis (PHA)[i] and did not affect decisions concerning control of sulfidation corrosion during the crude unit turnaround process.[ii]

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[i] A process hazard analysis is a hazard evaluation to identify, evaluate, and control the hazards involved in a process. Facilities that process a threshold quantity of hazardous materials, such as the Chevron Richmond refinery, are required to conduct a process hazard analysis per the California Code of Regulations Title 8 Section 5189. Process Safety Management of Acutely Hazardous Materials (1992). PHAs are also required by the California Accidental Release Prevention Program and the federal EPA Risk Management Program.

[ii] The turnaround process includes both the planning stage prior to the shutdown and the activities staged during the shutdown.

Other Significant Sulfidation Occurrences

25. The refining industry has experienced numerous sulfidation corrosion failures, primarily in piping.[28] API RP 939-C identifies 45 sulfidation corrosion failures, one third of which were found to have occurred in carbon steel piping containing low levels of silicon.[29]

26. The August 6, 2012, Chevron Richmond Refinery 4-sidecut pipe rupture was not the first sulfidation corrosion-related incident to occur at a Chevron refinery. In 1988, a low silicon carbon steel (0.02 wt. % silicon) piping component failed at the Chevron's former El Paso Refinery[i] in El Paso, Texas. In addition, two sulfidation corrosion incidents occurred at the Chevron Pascagoula refinery in Pascagoula, Mississippi: one in 1993 and one in 1988 on a low-silicon carbon steel component.

27. In 2002, the Chevron Salt Lake City Refinery experienced a fire when process piping failed as a result of sulfidation corrosion in a low silicon ASTM A53 carbon steel piping component. Chevron communicated the incident throughout the company in a technical newsletter. Chevron experts found that despite regular monitoring of the line for 30 years in compliance with industry standards, their inspection program failed to prevent the failure. Corrosion rates at the unmonitored failure location were found to be five times greater than corrosion rates at the monitored piping locations. The monitored locations were constructed of high silicon ASTM A106 piping (Figure 12). Chevron also found that in the years preceding the failure, both the temperature[ii] and hydrogen sulfide concentration in the process had been increasing. Each of these factors increased corrosion rates and contributed to the failure. In 2003, following this incident, Chevron experts recommended that refineries inspect every piping component (100 % component inspection) in all high-risk piping systems: those operating above 550 °F and containing hydrogen sulfide.

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[i] The El Paso Refinery is now owned by Western Refining.

[ii] The temperature in the line had been increased by over 170 °F throughout the life of the unit. During the two years prior to failure, temperatures of the line exceeded the measurement capabilities of the temperature measurement device and so the actual temperature increase cannot be determined.

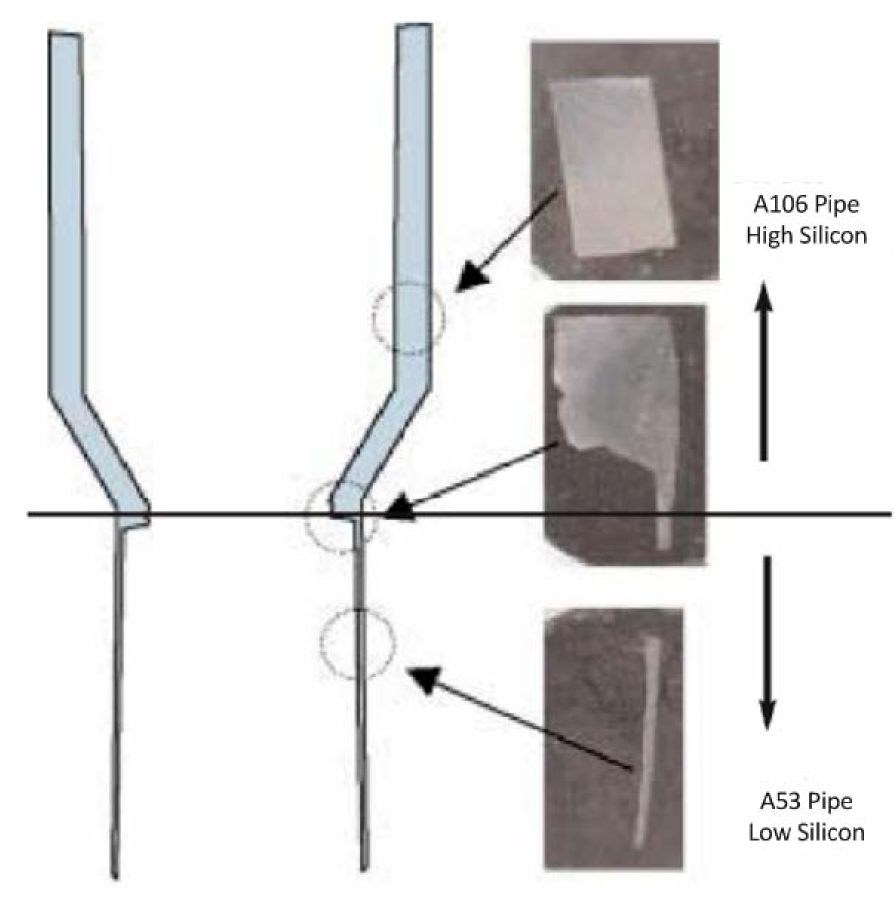

Figure 12. Schematic of failed piping from the Chevron Salt Lake Refinery. Similar to the Chevron Richmond Refinery incident, the failed piping contained low amounts of silicon and corroded significantly faster than adjacent piping components.

28. In January 2007, a failure due to sulfidation corrosion caused a serious fire in the Chevron Richmond Refinery crude unit resulting in a CWS Level 3 alert, initiating a shelter-in-place for the surrounding community. A carbon steel piping spool[i] failed catastrophically during operation (Figure 13). The carbon steel piping contained a low percentage of silicon (<0.005 wt. %). The process fluid ignited, injuring a nearby worker. Chevron informed Contra Costa Health Services' Hazardous Materials Program[ii] (Contra Costa County) in a letter that the metallurgy had been upgraded following this incident as an inherently safer solution. However, the CSB learned that this upgrade was limited to only the immediate piping spool that failed. The inherently safer, more corrosion resistant metallurgy was not implemented more broadly in crude unit high temperature service as a result of this incident.

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[i] A piping spool is a small, removable section of piping. In some cases, a piping spool is installed or removed in order to provide a temporary connection or complete disconnection between two piping circuits.

[ii] Contra Costa Health Services' Hazardous Materials program is designed to respond to emergencies and monitor hazardous materials within Contra Costa County. *See* http://cchealth.org/hazmat/ (accessed April 17, 2013).

Figure 13. Failed piping component that resulted in the 2007 Richmond crude unit fire. This carbon steel piping was found to contain less than 0.005 percent silicon.

29. Following the August 6, 2012, incident, personnel at the Chevron El Segundo, California, refinery, a near duplicate of the Richmond refinery, inspected their refinery's crude unit 4-sidecut piping. Significant thinning was discovered in the line; the piping from the atmospheric crude column to the pumps was removed and substituted with 9-Chrome, an upgraded and inherently safer material of construction.

30. On November 9, 2009, the Silver Eagle refinery in Woods Cross, Utah, experienced a catastrophic piping failure due to sulfidation corrosion in a 10-inch pipe, while conducting a temporary operation at higher than normal operating temperature. The pipe was located on the

bottom of a reactor in the de-waxing unit. The failed pipe released hydrogen which subsequently exploded, damaging over 100 homes in the nearby neighborhood.

31. On October 6, 2011, an explosion and fire resulted from a catastrophic piping failure at a Canadian refinery in Regina, Saskatchewan, injuring 52 workers. The piping component that failed was substantially thinner than neighboring components. Prior to the incident, the company's inspection data indicated that wall thickness in the overall piping system was within acceptable limits. However, the specific component that failed was not inspected. Although Canadian authorities are still investigating, metallurgical testing has indicated that hydrogen sulfide corrosion contributed to the catastrophic failure.

32. In February 2012, the BP refinery crude unit in Cherry Point, Washington, suffered a failure due to sulfidation corrosion, causing a large fire. This incident demonstrates that even when applying inherently safer concepts to reduce the potential for major hazards, it is still vital to fully understand all processes and piping configurations and incorporate a rigorous inspection program. The piping that failed was constructed of 9-Chrome. The line was used only during start-up operations and otherwise remained in-service and non-flowing. Such lines that do not have regular process flow yet remain in contact with process fluids are commonly referred to as "dead legs." The failure location was a high-point in the piping connected to the top of an operating process line. Hydrogen sulfide evolved from the process fluid and collected in the 9-Chrome piping. The concentrated vapor-phase hydrogen sulfide severely corroded the 9-Chrome, causing the failure. CMLs were located on adjacent elbow components; however, no CMLs were placed on the straight-run piping component where the failure occurred. The Cherry Point sulfidation failure demonstrates that even with more corrosion-resistant, inherently safer metallurgy, failure from sulfidation corrosion still may occur if piping is not effectively inspected or piping configurations are not adequately evaluated. In addition it is important to conduct a thorough analysis to determine the best material of construction for the process conditions.

Process Hazard Analysis

33. Chevron personnel analyze numerous deviations[i] for each portion of a process when conducting a Process Hazard Analysis (PHA). These include conditions such as changes in flow and temperature and pressure extremes. Specifically of interest, one of the deviations analyzed was “leak/rupture” of the particular vessel or pipe. For each deviation, the team’s responsibility was to identify causes, consequences, safeguards, and recommendations. The 4-sidecut line was analyzed in the most recent crude unit PHA. Corrosion was *not* identified as a potential cause of a leak/rupture in the piping (emphasis added).

34. Sometimes referred to as a corrosion review, a damage mechanism hazard review analyzes risks presented by all process failure mechanisms such as corrosion and cracking. Common process failure mechanisms are described in API 571: *Damage Mechanisms Affecting Fixed Equipment in the Refining and Petrochemical Industries*.[30] Such a review ensures that potential hazards caused by process conditions, process materials, and external mechanisms are properly identified, analyzed, and systems are put in place to control or eliminate the hazard. Despite Chevron knowledge and expertise of potential damage mechanisms (such as sulfidation corrosion), the CSB found these hazards are only identified in a PHA if the participants conducting the PHA happen to have personal knowledge of the relevant mechanism. The Chevron PHA teams do not typically seek assistance from corrosion experts.[ii] The inclusion of a damage mechanism hazard review as part of the PHA is not required by the state of California, the California Division of Occupational Safety and Health (Cal/OSHA),[iii] Contra Costa County, the City of Richmond,[iv] or Chevron standards. Because Chevron does not conduct, and is not required to conduct, a formal damage mechanism hazard review, damage mechanisms are only identified when the PHA team happens to have some knowledge of the mechanism. As a result, many damage mechanisms which occur in various processes are not properly addressed.

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[i] Deviations using guide words (such as no, more, less, as well as) and process parameters (such as flow, pressure, temperature) are analyzed in PHAs. *See* Center for Chemical Process Safety (CCPS). “Guidelines for Hazard Evaluation Procedures.” 2nd ed., Page 132, 1992.

[ii] The Crude Unit Business Improvement Network (BIN) Leader, a crude unit expert, reviews portions of the PHA with the PHA team. However, this review did not identify the potential for sulfidation corrosion failures in the 4-sidecut piping. A rigorous review of corrosion and damage mechanisms present in the crude unit was not performed during the PHA process.

[iii] The state of California, under an agreement with the federal Occupational Safety and Health Administration, or OSHA, operates an occupational safety and health program in accordance with Section 18 of the Occupational Safety and Health Act of 1970. *See* http://www.osha.gov/dcsp/osp/stateprogs/california.html (accessed April 17, 2013). The Department of Industrial Relations administers the California Occupational Safety and Health Program, commonly referred to as Cal/OSHA. The program applies to all public and private sector places of employment in the state, with some exceptions. *See* http://www.dir.ca.gov/dosh/dosh1.html (accessed April 17, 2013).

[iv] The City of Richmond adopted an ordinance on Industrial Safety, Richmond Municipal Code Chapter 6.43 (also known as the RISO), on December 18, 2001, “for the purposes of protecting public health and safety by prevention of accidental release of hazardous materials and to assure protection of the environment.” Richmond Municipal Code §6.43.040 (February 5, 2013). There are two facilities, including Chevron, that are located in the City of Richmond and subject to this ordinance. More information about the RISO is provided later in the report.

35. During a hazard analysis process such as a PHA, the evaluation team has to determine the likelihood of a hazardous consequence occurring. Then the team must identify safeguards which will reduce the risk of the hazard to an acceptable level. A recognized methodology for consistently and objectively making these determinations could include the use of quantitative, semi-quantitative, or qualitative tools.[31] Chevron does not employ a prescribed methodology for determining the likelihood that an incident will occur or whether a safeguard will be effective. Instead, Chevron relies upon the judgment of the people on the PHA team, who base their conclusions upon their collective experiences, beliefs, and areas of expertise. In its 2009 crude unit PHA, Chevron simply cited non-specific, judgment-based qualitative safeguards such as: utilizing metallurgy to minimize corrosion, having effective maintenance and inspection programs, and providing pipe wall corrosion allowances.[i] The effectiveness of these safeguards was neither evaluated nor documented; instead the safeguards were merely listed in the PHA. Had the adequacy of these safeguards been verified, improved safeguards intended to protect against sulfidation-induced failure of carbon steel piping could have been recommended.

36. Following the August 6th incident, Cal/OSHA inspected the Chevron facility and issued citations. Only one citation related to PHAs, and it was not associated with evaluating the effectiveness of safeguards. Rather, the emphasis was that Chevron's PHA did not adequately account for hazards caused by other units associated with the crude unit. The citation stated "The Employer [Chevron] failed to perform an effective Process Hazard Analysis [PHA] of the crude unit. Specifically, it failed to identify, evaluate, and control potential hazards caused by upstream and downstream units that provide and receive feed from the crude unit."[32] Had the Cal/OSHA regulation required documentation of the effectiveness of safeguards, Chevron would have been obligated to conduct this analysis and Cal/OSHA inspectors could rely on the regulation for support during inspections.

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[i] Corrosion allowance refers to extra wall thickness added as a safety factor to the design of a piece of equipment beyond that needed solely for mechanical considerations such as design temperature and pressure. This extra thickness is provided to accommodate for expected loss of wall thickness due to corrosion over the life of the equipment.

Operational Changes

37. The original design of the 4-sidecut circuit included equipment which had the effect of removing dissolved hydrogen sulfide, the most aggressive sulfur compound associated with sulfidation corrosion, from the 4-sidecut light gas oil process fluid. As a result, the 4-sidecut equipment was effective in reducing the sulfidation corrosion rate. This allowed the 4-sidecut equipment to be constructed of carbon steel. In 1991, this 4-sidecut equipment was taken out of service. No management of change[i] (MOC) was performed to analyze the effect of the elimination of this hydrogen sulfide-removing equipment on 4-sidecut corrosion rates. Such an MOC would have ensured that the increase in sulfur concentration on the carbon steel 4-sidecut piping was reviewed prior to removing the equipment.

38. Crude oil feedstock used at the Chevron Richmond Refinery is obtained from a variety of different sources that are blended before processing. These various crudes have different compositions, such as varying sulfur compounds and concentrations. These crudes can have differing corrosion effects on process equipment and piping. There is an increasing trend in crude oil refining to process less expensive “opportunity crudes” because they can provide significant cost savings to the company.[ii] However, these crudes may contain more undesirable characteristics such as high sulfur content, high naphthenic acid content, or very heavy hydrocarbons[33] that a refinery may not have been originally designed to process. Refinery equipment may not be the proper material of construction to achieve the design life of the equipment when exposed to the different operating conditions. Additional mitigation may be needed to reduce risk. In 1984, the Chevron Richmond Refinery crude oil feed contained approximately 85 volume % Alaskan North Slope (1 wt. %) crude oil. As the refinery began running more high-sulfur content crudes, the sulfur content in the 4-sidecut line steadily increased (Figure 14), as discussed below.

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[i] Management of change requires that employers have procedures to manage changes to process chemicals, technology, equipment, and procedures. The procedures must address the technical basis for the change, the impact on safety and health, and training required for employees affected by the change.

[ii] Crude oil costs can account for up to 90% of the operating costs in a refinery. *See* Qu, Dingrong, Xiaohui Liu, Xiu Jiang, Zhenggui Lan, and Guangbin Shan. “Setting Critical Operational TAN and Sulfur Level for Crude Distillation Units.” *Corrosion 2011 Conference & Expo.* Paper No. 11362. NACE International, 2011.

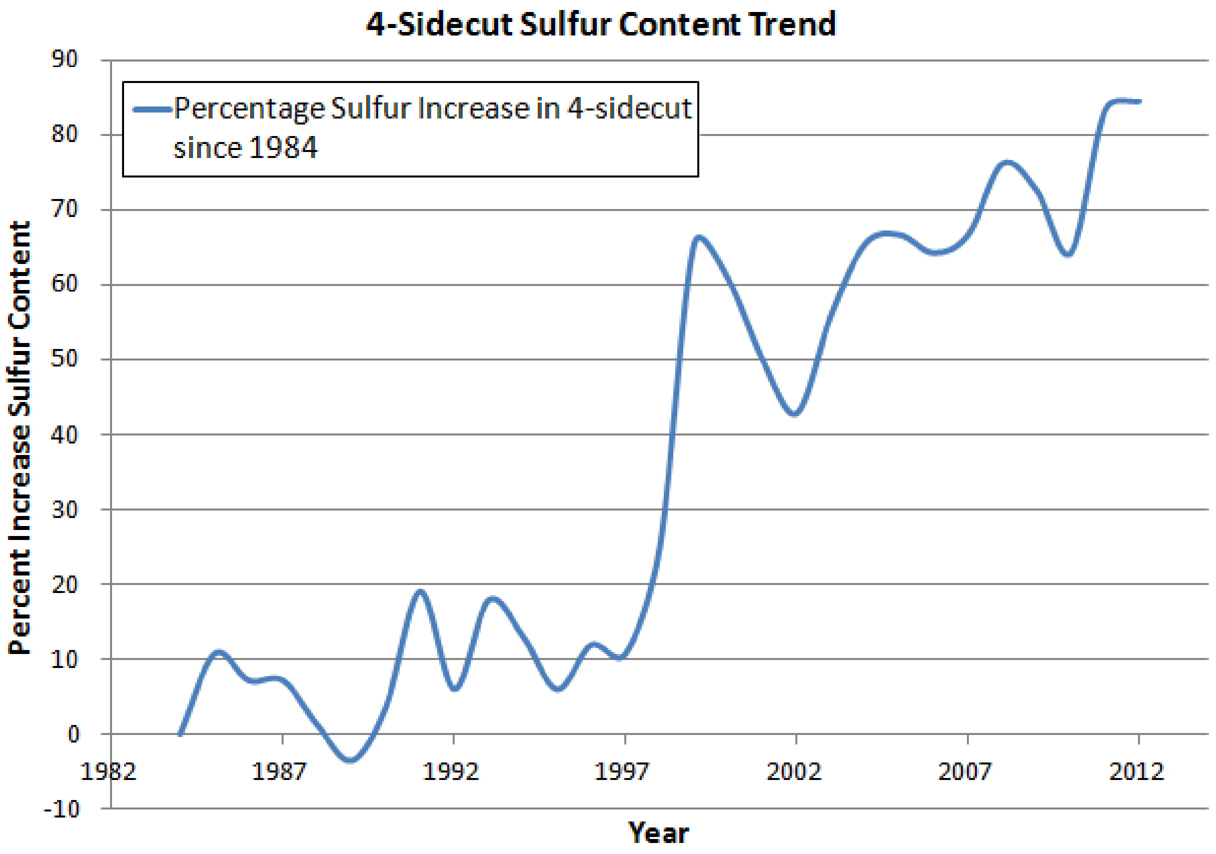

Figure 14. Graph shows the percentage increase from 1984 values of the sulfur content in the 4-sidecut.

39. When Chevron introduces a new crude, an MOC is generated to evaluate the potential impact on the refinery.[i] While Chevron stayed under its established crude unit design basis for total wt. % sulfur of the blended feed to the crude unit, the sulfur composition significantly increased over time. Historic data indicates that the sulfur in the 4-sidecut stream has increased from 0.8 to 1.6 wt%. This increase in sulfur composition likely increased corrosion rates in the 4-sidecut line. Chevron did not conduct an MOC analyzing the impact that increases in sulfur composition would have on corrosion in the crude unit. Chevron also did not change its corrosion monitoring programs in response to the increased sulfur content.

40. The CSB found that increased Chevron Richmond usage of non-domestic crude feed stock over time resulted in higher sulfur content in the process fluid passing through the 4-sidecut piping. Specifically, the percentage of sulfur in the Richmond refinery crudes increased nearly 85% between 1984 and 2012, including a significant jump of 32% from 1998 to 1999. This increase in sulfur content corresponded with a simultaneous increase in the usage of non-domestic crude feed at the Richmond refinery.

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[i] Chevron MOCs on new crudes considered general operational issues but did not analyze corrosion effects from sulfidation corrosion.

41. Sulfidation corrosion rates increase in piping circuits as temperature and sulfur content increase. Accordingly, the 4-sidecut sulfidation corrosion rate increased between 1984 and 2012 due to the increase in sulfur content in the line. The CSB found that for the 26-year period from the installation of the piping in 1976 through 2002, the 52-inch 4-sidecut component had lost approximately 33 percent of its wall thickness. From the single inspection of the 52-inch component in 2002 to the incident in 2012 – just ten years – an additional 57 percent of the original component nominal wall thickness was lost near the rupture location due to sulfidation corrosion.[i] In addition to the sulfur content increase, the 4-sidecut draw temperature increased from 625 °F in 1992 to 680 °F in 2002. Corrosion rates and remaining life calculations based on past sulfur content and temperatures may not accurately reflect current corrosion rates if process conditions have changed. Inspection based on historical corrosion rates may be too infrequent to detect an increase in corrosion caused by adverse changes in process conditions, potentially leading to equipment failure.

42. API RP 939-C states that refinery feed stock changes reduce the relevance of past inspection data when predicting future corrosion rates:

> Oil refineries that processed a consistent diet of a particular crude oil or crude blend could often base future predictions on past experience. However, over the past 20+ years, global economics have resulted in many refineries processing tens of different crudes in any given year; thus, minimizing the accuracy, or even feasibility, of predictions based on historical data. Additionally, the verification of the actual corrosion rate experienced while processing a specific crude oil is very difficult.[34]

43. API 570 *Piping Inspection Code: In-service Inspection, Rating, Repair, and Alteration of Piping Systems*, the API standard for inspecting piping, recommends companies to incorporate process changes into inspection programs. The standard states:

> The owner/user is … responsible for implementing an effective MOC process that will review and control changes to the process and to the hardware. An effective MOC process is vital to the success of any piping integrity management program in order that the inspection group will be able to anticipate changes in corrosion or other deterioration variables and alter the inspection plan to account for those changes. The MOC process shall include the appropriate materials/corrosion experience and expertise in order to effectively forecast what changes might affect piping integrity. The inspection group shall be involved in the approval process for changes that may affect piping integrity.

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[i] The 4-sidecut 52-inch component had an original wall thickness of 0.322 inches. Metallurgical analysis found the thinnest portion of the 52-inch 4-sidecut component was 0.03 inches.

> *Changes to the hardware and the process shall be included in the MOC process to ensure its effectiveness* [emphasis added].[35]

Chevron failed to comply with the requirements of API 570 when it did not conduct an MOC to thoroughly evaluate the change of increasing sulfur weight percentage in crude oil feed and to assess how it might affect corrosion rates within the 4-sidecut piping circuit. After the August 6, 2012, incident, Cal/OSHA inspected the Chevron Richmond Refinery and issued citations.[i] However, Cal/OSHA did not issue any citations for failing to perform an MOC when sulfur composition in the crude oil feed was increased.

Chevron Sulfidation Corrosion Inspection and Mitigation

44. In the ten years prior to the incident, a small number of Chevron personnel with knowledge and understanding of sulfidation corrosion made at least six recommendations (listed in the following six paragraphs and included in Figure 15) to increase inspections or upgrade the metallurgy in the 4-sidecut piping. The recommendations made by these personnel were not implemented by Chevron management.

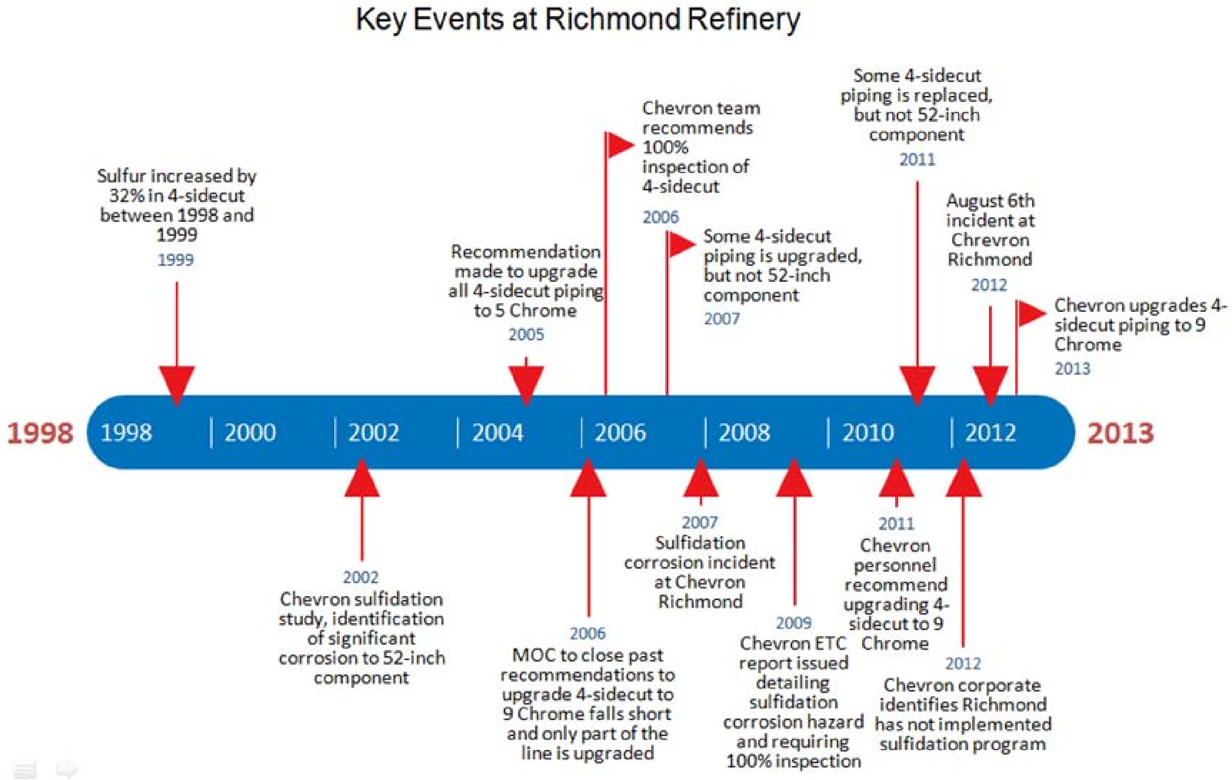

Figure 15. Key events at the Richmond refinery between 1998 and 2013.

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[i] Cal/OSHA citations issued January 30, 2013.

45. In August 2002, a Chevron Richmond Refinery employee performed a study analyzing sulfidation corrosion rates in the crude unit and identifying potentially vulnerable areas. The employee discovered that the 4-sidecut operating temperature had been increased and concluded that this increase would cause more hydrogen sulfide to evolve, leading to increased sulfidation corrosion rates. As a result of these findings, the employee recommended increased inspection of the 4-sidecut piping and noted that this piping might need to be upgraded from carbon steel to 5-Chrome, a steel alloy that is more resistant to sulfidation corrosion. In 2002, proactively following up on this study, the crude unit inspector conducted additional piping inspection and identified accelerated corrosion in the 52-inch 4-sidecut component. The inspector recommended upgrading this piping during the next shutdown in 2007. In the inspector's 2002 accomplishments, Chevron management acknowledged this effort to prevent a significant incident; it was characterized as "a save." However, during the 2007 turnaround the recommendation was not implemented, and because a CML was not added to the inspection program, the 52-inch component was not inspected after 2002.

46. In February 2006, a team consisting of a materials and corrosion engineer, an inspector, a process engineer, a metallurgist, and a design engineer issued a Corrosion Mitigation Plan for the Chevron Richmond Refinery crude unit. The report specifically identified the 4-sidecut piping to be at risk for high temperature sulfidation corrosion. The report described that low silicon carbon steel can corrode faster than carbon steel manufactured with higher silicon content, and recommended that 100 percent inspection be performed on the 4-sidecut line using continuous monitoring technology. During the 2007 crude unit turnaround, continuous monitoring probes were only installed on a segment of the 4-sidecut line that did not include the 52-inch component that ultimately failed. The 100 percent inspection recommended in the 2006 Corrosion Mitigation Plan was not performed.

47. During the 2007 turnaround, the crude unit inspector recommended that the refinery upgrade the entire 4-sidecut piping with 5-Chrome. The recommendation was based on findings obtained during the 2002 crude unit turnaround, where the crude unit inspector found that the 52-inch 4-sidecut component had lost one-third of its wall thickness due to corrosion. However, after evaluation, this recommendation was not accepted by the turnaround planning team. Basing its decision on limited inspection data, Chevron determined that the 8-inch portion of the 4-sidecut piping that ran from the atmospheric column to the pump, the portion which included the 52-inch component, had sufficient wall thickness to last to the next turnaround scheduled for Fall 2011.[i] The piping downstream of the pump, which operates at a higher pressure, was determined not to have sufficient wall thickness to last to the next turnaround. This piping was removed and replaced with 9-Chrome, an upgraded and inherently safer metallurgy. The 52-inch component of the 8-inch piping between the atmospheric column and the pump was not replaced during the 2007 turnaround even though it had been identified as thinned in 2002.

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[i] This decision was made without reinspecting or evaluating the thickness of the thinned 52-inch component identified in 2002 that prompted the recommendation.

Furthermore, a permanent CML was not placed on the 52-inch component, and it was not entered into the inspection database. As a result, the component was not inspected again.

48. In September 2009, Chevron ETC corrosion experts released a formal technical report discussing sulfidation corrosion and the specific issues associated with carbon steel, including the potential for high corrosion rates in carbon steel piping containing low percentages of silicon. In its report, Chevron ETC issued recommendations for inspection and provided guidelines for prioritizing piping circuits susceptible to sulfidation corrosion so that high-risk lines could be evaluated first. It was recommended that 100 percent component thickness testing be completed on all high priority lines one time to identify thin, low-silicon components to establish a baseline of corrosion rate and risk for failure. Following the release of the report, the Chevron Richmond Refinery materials group completed the risk-ranking of the carbon steel piping in the Richmond Lube Oil Project (RLOP) and in the crude unit, two units known to be susceptible to sulfidation corrosion. The group identified the crude unit 4-sidecut line as a high risk line per the report ranking guidance. Instead of completing the 100 percent component inspection, the 4-sidecut was recommended for replacement with 9-Chrome. However, the replacement recommendation was denied because the available, limited inspection data indicated the piping would last until the next turnaround. Subsequently, the alternative 100 percent component inspection was also never performed.

49. Five months prior to the incident in March 2012, a Chevron corporate review of Richmond identified that inspection of all carbon steel components susceptible to sulfidation corrosion was not being performed at the Richmond refinery. In addition to identifying that CMLs were not in the proper locations, this corporate review found that critical inspection recommendations were being submitted to the shutdown planning process, but were being denied. Chevron corporate identified that Richmond refinery leadership needed to review and implement the 2009 Chevron ETC report recommendations.

50. Chevron conducts “Intensive Process Reviews” prior to turnarounds. This process involves knowledgeable individuals including Business Improvement Network leaders, process engineers, metallurgical engineers, design engineers, and turnaround planners. The purpose of the review is to identify key unit issues that should be addressed and repaired during the unit turnaround. Prior to the 2011 crude unit turnaround, Chevron personnel conducted an Intensive Process Review of the crude unit and specifically recommended that the 4-sidecut carbon steel piping “should be upgraded to 5 Cr [5-Chrome]… due to sulfidation.” Although the Intensive Process Review identified sulfidation problems in the 4-sidecut line, this activity was ineffective. The 4-sidecut piping was not upgraded during the 2011 crude unit turnaround.

51. In preparation of the work list for the 2011 crude unit turnaround, the crude unit inspector and crude unit metallurgist recommended that the 4-sidecut line be replaced with an upgraded metallurgy, 9-chrome, the metallurgy recommended in the Chevron new construction guidelines for piping in high temperature and high sulfur service. The recommendation was based on the

high priority ranking of the 4-sidecut line, corrosion history, and both Chevron and industry recommended best practice. However, the turnaround management team determined that the inspection data available for the 4-sidecut piping, from CMLs on elbow components which are less prone to sulfidation corrosion, did not support a material upgrade during the 2011 turnaround.[i, ii] The lack of data on the more susceptible 4-sidecut straight-run piping components was not considered.

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[i] This decision was made without reinspecting or evaluating the thickness of the 52-inch component identified in 2002.

[ii] A portion of the 4-sidecut 12-inch line was replaced during the 2011 turnaround with carbon steel due to thinning caused by sulfidation corrosion.

Inherently Safer Systems

52. The Center for Chemical Process Safety (CCPS) is a corporate membership organization that identifies and addresses process safety needs within the chemical, pharmaceutical, and petroleum industries.[36] Chevron is a corporate member of CCPS.[37] The CCPS book *Inherently* Safer *Chemical Processes, 2nd ed.* defines inherently safer design as the process of identifying and implementing inherent safety in a specific context that is permanent and inseparable.[38] In the book *Guidelines for Engineering Design for Process Safety, 2nd ed.*, CCPS states "inherently safer design solutions eliminate or mitigate the hazard by using materials and process conditions that are less hazardous."[39]

53. Inherently safer technologies are relative; a technology can only be described as inherently safer when compared to a different technology with regard to a specific hazard or risk.[40] A technology may be inherently safer with respect to one risk but not safer from another risk. For this reason, it is important to carry out a comprehensive, documented hazard analysis to determine the individual and overall risks in a process and assess how the risks can be effectively minimized to control hazards. An inherently safer systems review details a list of choices offering various degrees of inherently safer implementation. The review should include risks of personal injury, environmental harm, and lost production, as well as evaluating economic feasibility.[41]

54. 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.[42] Process upgrades, rebuilds, and repairs are additional opportunities to implement inherent safety concepts. Conducting a comprehensive hazard review to determine risks and identify ways to eliminate or reduce risks is an important step in implementing an inherently safer process. Chevron training programs on inherently safer systems reflect this approach, stating "we have the greatest opportunity to eliminate or minimize hazards during the development phase of new projects or major revamps of existing facilities."

55. After a 2007 incident caused by a pipe failure in the Richmond refinery crude unit, Chevron implemented an "Inherently Safer Solution" by upgrading the piping to metallurgy that was less susceptible to sulfidation corrosion. However, the change was implemented intuitively without a supporting inherent safety review or failure mechanism hazard review to provide a detailed documented technical rationale for the metallurgy selection. Without such a review, the material selected cannot be analyzed to determine if it is the best inherently safer solution for the process in order to minimize risk.

56. Following the August 6, 2012, incident, the 4-sidecut piping circuit at the Richmond refinery was upgraded from carbon steel to 9-Chrome.[i] However, Chevron did not produce a documented inherently safer hazard review before commencing the rebuild of the crude unit. The crude unit at the Chevron El Segundo refinery is nearly identical in construction and design to the Richmond refinery crude unit. Chevron informed the CSB that piping *downstream* of the 4-sidecut pumps in the 4-sidecut piping circuit at the El Segundo refinery was upgraded in 2001[ii] from carbon steel to stainless steel. As stated previously, after the August 6, 2012, Richmond incident, the 4-sidecut piping *upstream* of the 4-sidecut pumps at the El Segundo refinery was upgraded from carbon steel to 9-Chrome. Had a comprehensive inherently safer systems review been conducted at the Richmond refinery following the August 6th incident, a different metallurgy, such as stainless steel which was installed at the Chevron El Segundo Refinery, may have been identified as inherently safer than 9-Chrome with respect to sulfidation corrosion.

57. An effectiveness ranking of techniques used to control hazards and the risk they represent can be described as a hierarchy of controls. The further up the hierarchy, the more effective the risk reduction achieved (Figure 16). All concepts in the hierarchy of controls should be included in the process of risk assessment and reduction. Upgrading metallurgy to a more corrosion resistant material may be a high ranking, inherently safer choice for certain corrosion mechanisms, such as sulfidation corrosion. Holding other variables constant, upgrading the material of construction may reduce the severity of corrosion and the likelihood of a failure.

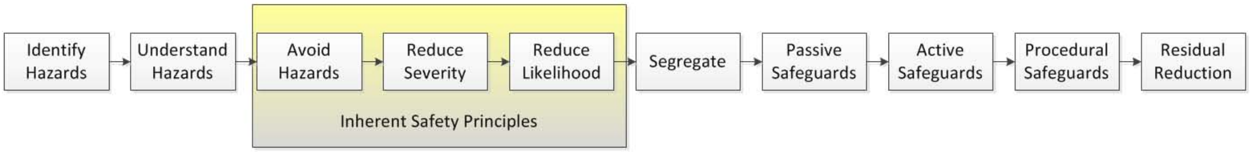

Figure 16. Hierarchy of controls. The boxes reflect inherently safer controls from left to right, based on *Process Plants: A Handbook for Inherently Safer Design Second Edition*; Kletz, Trevor Amyotte, Paul; CRC Press 2010.

58. Chevron employees have recommended implementing inherently safer designs through the MOC process, incident investigations, technical reports, and recommendations from employees in the past. However, the CSB has not identified any documented, thorough analysis of the proposed inherently safer solutions. In addition, Chevron has repeatedly failed to implement proposed inherently safer recommendations. For example, following the discovery of significant 4-sidecut piping sulfidation corrosion in 2002, a Chevron inspector issued the following recommendation to replace the piping in the 2007 turnaround:

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[i] After the 2012 incident, the Richmond refinery stated that stainless steel was susceptible to chloride stress corrosion cracking and should not be used.

[ii] Chevron verbal estimate for date of piping installation. No MOC was conducted to review and document this change.

> INFORMATION
>
> The #4 sidecut piping from C-1100 to P-1149/A to E-1113 was RT (x-ray) inspected for hot H2S [sulfidation] corrosion. The piping is actively corroding, particularly on the section on the discharge line from the pumps near the exchanger; the line upstream of the P-1149/A pumps is corroding as well. Corrosion rates indicate that the piping has 4 years of remaining life until the refinery throwaway thickness of 0.14” [inch] is reached. The carbon steel piping is currently running at temperatures between 650 °F on the pump suction line to 641 °F on the line just before E1113; the upper limit for carbon steel piping in this service is 550 °F. A materials upgrade to 5 chrome would raise the upper limit to between 650-750 °F. Additionally, the ABCR piping loop from the same sidecut draw line off of the column to P-1148/A to E-1111 is also carbon steel and operates at the same temperatures, rendering the ABCR piping system to E-1111 susceptible to hot H2S corrosion as well.
>
> Recommendation
>
> Replace the existing #4 sidecut piping noted above from C-1100 through P-1149/A to E1113 and P-1148/A to E-1111 (approximately 700’[feet] of 12”, 10”, 8” and 6”piping, plus some 4”and 3” at the P-1149/P-1148 suction/discharge headers). Upgrade the pipe material from carbon steel to 5 chrome.

To implement this recommendation, Chevron initiated an MOC in 2006 to replace the piping during the 2007 Turnaround. However, the MOC supporting documents had a narrowed scope to only replace the section of piping from P-1149/A pumps to the E-1113 heat exchanger because Chevron reduced the work scope during the 2007 turnaround planning process. The Description of Change in the MOC stated:

> Existing line is carbon steel in a hot service that operates in the range where high temperature sulfadation [sic] occurs. The line has been ut[i] inspected and found to be nearing tmin[ii] requiring replacement. Due to the higher temperature 9CR [9-Chrome] would be the prefered [sic] material.

Contradicting this Description of Change detailing a replacement of the entire 4-sidecut piping circuit, the MOC Summary Review and attached documentation only authorized replacement of the piping from the P-1149’s to E-1113. The MOC states:

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[i] UT is an abbreviation used to indicate ultrasonic thickness testing inspection technique.

[ii] Tmin is an abbreviation used to indicate minimum required piping wall thickness.

> 4 S/C piping has been operating hotter in recent years. The hotter temperatures 550 °F are in the high temperature sulfadation [sic] range. Additionally the section of 4 S/C piping from P-1149' s to E-1113 has been found to be nearing tmin.
>
> The section of pipng [sic] from P-1149's to E-1113 will be replaced with 9 Cr [9-Chrome] piping.

As a result, the portion of the piping containing the 52-inch component that failed on August 6th remained in service. Although the recommendation was intended to more broadly apply inherently safer materials of construction, the final implementation by the MOC limited the application of this more corrosion resistant metallurgy.[i] Again, the inherently safer, more corrosion resistant, metallurgy was not implemented more broadly in crude unit high temperature service. Other examples are discussed above in the section entitled *Chevron Sulfidation Corrosion Inspection and Mitigation*.

59. In 2007, the Chevron Richmond Refinery conducted training to teach employees about the importance of complying with the City of Richmond's Industrial Safety Ordinance (RISO)[ii] inherent safety guidance. The training states "we should always strive to implement inherently safer strategies to the greatest extent feasible." However, Chevron did not regularly or rigorously[iii] apply inherently safer design strategies in opportunities including PHAs, MOCs, incident investigation recommendations, and during turnarounds.[iv]

60. Chevron uses an inherently safer design checklist[v] for PHAs to meet inherently safer systems analysis requirements of the RISO. The checklist, provided by Contra Costa County, is intended to aid identification of opportunities to implement inherently safer design during the PHA process. The checklist was intended to stimulate discussion and analysis of potential opportunities to implement inherently safer design. Contra Costa County's guidance on the IST checklist states that some items may need to be reviewed by a team that is outside the PHA team in order to involve people with the required expertise. Chevron utilized the Contra Costa County inherently safer technologies checklist (IST Checklist) during the 2009 crude unit PHA.

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[i] As discussed earlier, only the section of piping downstream of the pumps was replaced with 9-Chrome.

[ii] The RISO will be discussed in more detail in the *Regulatory Oversight* section below.

[iii] Chevron does not utilize inherent safety guidewords or checklists during the MOC or incident investigation process. Inherently safer guidewords help direct the inherently safer review process. Examples of guidewords include minimization, substitution, moderation, and simplification. These words may be applied to materials, product inventory, process controls, process piping, and siting, among others. *See* Center for Chemical Process Safety (CCPS). "Inherently Safer Chemical Processes – A Life Cycle Approach." 2nd ed., Table 8.3, 2009.

[iv] As stated in the *Regulatory Oversight* section below, Chevron is only required to conduct inherently safer design strategies during PHAs and for the construction of new processes.

[v] Contra Costa County's guidance document entitled "Attachment C: Inherently Safer Systems Checklist" is provided as a tool for facilities to utilize during the PHA process. The actual use of the checklist is not required. *See* http://cchealth.org/hazmat/pdf/iso/attachment_c.pdf (accessed April 17, 2013).

However, only three permissively worded[i] inherently safer system recommendations were made, none of which addressed sulfidation corrosion or piping metallurgy. In addition, Chevron performed the checklist analysis using the same individuals who conducted the PHA despite Contra Costa County's guidance to involve other personnel with additional expertise. Performing a superficial analysis, Chevron failed to adequately consider inherently safer systems like improved metallurgy for corrosion resistance. For instance, the checklist prompted: "Use corrosion resistant material?" In response, Chevron stated that "vessel specifications and piping classifications include a conservative wall thickness and an appropriate corrosion allowance for each service." No mention is given to improving metallurgy to reduce corrosion. There is also no documented analysis regarding potential materials with enhanced corrosion resistance. There was no documentation of the inherently safer technologies analysis, and no inherently safer alternatives were documented. The checklist as applied by Chevron was a "check-the-box" exercise. Chevron Richmond PHAs were thus not an effective means of driving inherent safety. The table below gives a sample of the IST checklist questions along with the associated Chevron responses.[ii]

Contra Costa County Checklist Question	**Chevron IST Analysis**
Use Corrosion resistant materials?	Vessel specifications and piping classifications include a conservative wall thickness and an appropriate corrosion allowance for each service.
Use smallest diameter piping?	Piping sizes are the smallest possible for the capacity of the unit.
Substitute less hazardous raw materials?	Raw materials in use are of minimal hazard.
Dilute hazardous raw materials?	Raw materials currently dilute where applicable.
Minimize off-site impacts?	#4 Crude Unit is located at a distance from public areas.
Easy operation of valves designed to prevent inadvertent error?	In general, valves are arranged in a logical manner.
Increasing wall strength?	Piping classifications include a conservative wall thickness and an appropriate corrosion allowance for each service.

61. Contra Costa County inspected the Chevron Richmond Refinery in 2011, auditing Chevron's implementation of the county's inherently safer systems analysis requirements in the PHA process. The inspectors determined that Chevron's PHAs "follows the requirements specified by … ISS [inherent safety systems] guidelines." This approval by Contra Costa County

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[i] All began with "consider" and two began with "consider evaluating" which does not require any action by Chevron.

[ii] The comprehensive list of IST checklist questions and Chevron's corresponding answers are provided separately on the CSB website.

conveyed to Chevron that the regulator considered that Chevron's minimal analysis of opportunities to implement inherently safer design, its "check-the-box" exercise, was sufficient.

62. Effectively implementing inherently safer technology provides an opportunity for preventing major chemical incidents. The August 6, 2012, incident at Chevron and other incidents[43] throughout the refining industry highlight the difficulty in preventing failure caused by sulfidation corrosion in low silicon carbon steel piping solely through inspection, a procedural safeguard that is low on the hierarchy of controls. Using inherently safer design concepts to avoid issues such as variation in corrosion rate in carbon steel piping due to hard-to-determine silicon content will reduce future similar failures in refineries. Chevron and other process plants' implementation of inherently safer systems to the greatest extent feasible would provide a higher degree of protection from incidents like the one that occurred on August 6, 2012.

63. It is essential that MOCs incorporate hazard analyses and the assessment of opportunities to implement inherently safer systems. This process can be assisted through the use of guidewords to trigger the thought process. CCPS states that "by including inherent safety guidewords in a management of change program, the MOC protocol recognizes inherent safety as both a driving force for - and as an opportunity during - implementation."[44]

64. Layer of Protection Analysis (LOPA) is a well-recognized hazard analysis methodology that is intended to determine if a sufficient number of safeguards or layers of protection exist to protect against a particular hazard or accident scenario.[45] As the potential consequence of a particular scenario increases, the number of safeguards or protection layers must increase to reduce the risk of the scenario to what is considered an acceptable or tolerable level.[46] LOPA can be used to help an organization decide if the risk of a scenario or hazard has been reduced to a level that is "as low as reasonably practicable" (ALARP).[47] ALARP is a risk reduction goal, where risk reduction efforts are continued until the incremental effort to further reduce risk becomes grossly disproportionate to the level of additional risk reduction.[48] By rigorously reviewing accident or hazard scenarios, evaluating the potential consequence of the scenario, and identifying the safeguards or layers of protection necessary to drive risk to as low as reasonably practicable, LOPA becomes an effective organizational tool for implementing a Process Safety Management (PSM) mechanical integrity program.[49] LOPA also helps an organization decide which safeguards to focus on during operation, maintenance, and training.[i, 50] In addition, the LOPA methodology includes provisions allowing an organization to determine the availability[ii] and effectiveness of a safeguard or layer of protection in reducing the risk of a potential scenario.[51]

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[i] Chevron is a member of CCPS and peer-reviewed the CCPS LOPA publication. *See* Center for Chemical Process Safety (CCPS). "Layer of Protection Analysis – Simplified Process Risk Assessment," page xiv, 2001.

[ii] The probability that a system will be able to perform its designated function when required for use. Another term frequently used is *Probability of Failure on Demand* (PFD). Availability = 1 - PFD. *See* Center for Chemical Process Safety (CCPS), "Guidelines for Safe Automation of Chemical Processes," page XIX, 1993.

Regulatory Oversight

65. The Contra Costa County Industrial Safety Ordinance (ISO) requires that regulated facilities[i] within the county implement safety programs to prevent chemical incidents. Since the ISO took effect in January 1999, Contra Costa County has continued to make improvements to the implementation of the prevention program's elements.

66. The purpose of the ISO is to "prevent accidental release of hazardous chemicals; improve accident prevention by soliciting participation from industry and the community; require industry to submit a Safety Plan; and conduct audits of the plan and inspections of the industrial plants."[52]

67. Although the City of Richmond is located in Contra Costa County, the county does not have jurisdiction over industrial facilities located within the city limits. Thus, the ISO is not enforceable within the City of Richmond. On December 18, 2001, the City of Richmond adopted its own industrial safety ordinance (RISO), based on the ISO.[ii, 53] The RISO covers the two facilities located within the City of Richmond: Chevron and General Chemical West Richmond Works.[54] Pursuant to an agreement between the two parties, Contra Costa County inspects these two facilities and implements the RISO for the City of Richmond.[55]

68. The ISO and RISO contain identical provisions that address the use of inherent safety concepts. Each defines "inherently safer systems" as "feasible alternative equipment, processes, materials, lay-outs and procedures meant to eliminate, minimize, or reduce the risk of a major chemical accident or release by modifying a process rather than adding external layers of protection."[56] Both regulations also require that:

> For all covered processes, the stationary source shall consider the use of inherently safer systems in the development and analysis of mitigation items resulting from a process hazard analysis and in the design and review of new processes and facilities. The stationary source shall select and implement inherently safer systems to the greatest extent feasible. If a stationary source concludes that an inherently safer system is not feasible, the basis for this conclusion shall be documented in meaningful detail.[57]

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[i] The ISO applies to oil refineries and chemical plants within the county jurisdiction that are required to submit a Risk Management Plan to EPA and are program level 3 stationary sources as defined by the California Accidental Release Prevention (CalARP) Program. There are seven facilities covered by the ISO, five of which are refineries. *See* http://cchealth.org/hazmat/iso/ (accessed April 17, 2013).

[ii] At the time of the August 6th incident, the RISO did not include amendments made to the ISO in 2006. The 2006 amendments required an expansion of human factors programs, expanded management of organizational change reviews, security vulnerability analyses, and safety culture assessments. These amendments were subsequently adopted by the City of Richmond in February 2013. *See* http://cchealth.org/hazmat/iso/ (accessed on April 9, 2013).

69. The apparent intent of the ISO and RISO regulations is to require companies to evaluate their processes in order to identify opportunities to implement inherently safer systems. However, the plain language contained within these regulations conflicts with this intent. Both regulations contain the following permissive language: "the stationary source *shall consider* the use of inherently safer systems…"[58] This language does not require companies to conduct a comprehensive analysis and implement inherently safer systems even where feasible. It only requires such an analysis be considered. The regulations allow companies to merely engage in an activity contemplating the potential use of inherently safer systems.

70. The language within the ISO and RISO regulations also requires effective action to implement inherently safer systems "to the greatest extent feasible."[59] If an inherently safer system is not implemented, the regulations require that the basis for this decision be "documented in meaningful detail." [60] However, these regulations do not require documentation supporting the adequacy of existing "inherently safer" [61] claims. Chevron's compliance with the RISO is indicative of this deficiency. In its inherently safer systems checklist, Chevron simply concluded that its systems were inherently safer to the extent that no modifications were necessary. However, the company offered no documentation to substantiate these claims. Had the ISO and RISO regulations required analysis of inherently safer systems regardless of what the site already had in place, Chevron may have implemented the inherently safer recommendations made by technical staff to replace the 4-sidecut with an inherently safer metallurgy.

71. The inherently safer systems requirements of the ISO and RISO are only triggered by the conduct of a PHA or the construction of a new process.[62] Rebuilds, repairs, MOCs, and the implementation of incident investigation corrective actions do not require the analysis and application of inherently safer systems.

72. The Contra Costa County PHA guidance document presents four categories of risk reduction:[i] inherent, passive, active, and procedural (Figure 15).[ii] It states that all four categories should be used in the development of recommendations from process hazard analyses.[63] It reiterates the CCPS statement that all may contribute to the overall safety of a process, but that inherent safety is the most effective.[64] It goes on to state "The inherent and passive categories should be implemented when feasible for new processes and facilities and used during the review of Inherently Safer Systems for existing processes if these processes could cause incidents that could result in a Major Chemical Accident or Release."[65] This wording in the guidance

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[i] The guidance document uses CCPS definitions for the identified categories of risk reduction.

[ii] Inherent risk reduction involves eliminating the hazard by using materials and process conditions that are non-hazardous. Passive risk reduction is defined as minimizing the hazard through process and equipment design features that reduce the frequency or consequence of the hazard without active functioning of any device. Active risk reduction includes using controls, alarms, safety instrumented systems, and mitigation systems to detect and respond to process deviations from normal operation. Procedural risk reduction achieves the lowest level of risk reduction and involves using policies, operating procedures, training, administrative means, emergency response, and management approaches to prevent incidents and minimize the effects of an incident.

document demonstrates the importance Contra Costa County places on risk reduction and prevention such as metallurgy upgrades; however, as a guidance document, it is non-mandatory.

73. The California Division of Occupational Safety and Health (Cal/OSHA) has jurisdiction over employee safety in California.[66] Cal/OSHA is a division of the California Department of Industrial Relations and has operated a state plan industrial health and safety program since 1973 under a delegation from the U.S. Occupational Safety and Health Administration (OSHA). Cal/OSHA conducts inspections of California workplaces in response to industrial accidents, safety complaints, or as part of an inspection program targeting specific industries.[67] Consideration of inherently safer processes is not currently a required component of any Cal/OSHA (or federal OSHA) standard or regulation.[i]

74. The State of California has promulgated process safety regulations similar to OSHA[68] for the prevention or minimization of the consequences of the accidental release of acutely hazardous chemicals.[69] These regulations require that covered employers perform a PHA to identify, evaluate and control hazards involved in the process using recognized methodologies.[70]

75. California regulations, however, do not provide for a specific review of the effectiveness of the proposed safeguards to control the hazards identified in the PHA using recognized methodologies such as Layers of Protection Analysis (LOPA).[71] Additionally, California regulations do not have any requirements for the use of inherently safer systems analysis and the hierarchy of controls for establishing safeguards for identified process hazards. Cal/OSHA, like federal OSHA, also does not require damage mechanism hazard reviews as part of the PHA process.

76. The Energy Institute, an industry technical working group[ii] organized in the United Kingdom (UK), with contributions from regulators including the UK's Health and Safety Executive (HSE),[iii] as well as other entities,[iv] developed a document in 2008[v] that provides guidance on damage mechanism hazard reviews in the UK's offshore petrochemical industry. The guidance states that effective management of corrosion will contribute to equipment integrity and reduce risk from safety and environmental hazards.[72] In addition, during the design of a process, a corrosion review can be used to eliminate risks and achieve inherent safety.[73] The guidance also

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[i] This is also the case for US EPA Risk Management Program and the California Accidental Release Prevention Program regulations.

[ii] The Energy Institute is the leading chartered professional membership body supporting individuals and organizations across the energy industry. With a combined membership of over 13,500 individuals and 300 companies in 100 countries, it provides an independent focal point for the energy community and a powerful voice to engage business and industry, government, academia and the public internationally. *See* http://www.energyinst.org/about-us (accessed April 17, 2013).

[iii] HSE is an independent regulator that is tasked with securing the health, safety and welfare of workers within the UK. *See* http://www.hse.gov.uk/aboutus/index.htm (accessed April 17, 2013).

[iv] Chevron Energy Technology Company (ETC) was one of roughly 30 entities recognized in the guidance document as providing contributions to the institute that were "key to the development of this publication…". *See* http://www.energyinstpubs.org.uk/pdfs/815.pdf (accessed April 17, 2013).

[v] *Ibid.*

notes that damage mechanism hazard reviews should provide a structured framework for identifying risks associated with corrosion and developing suitable risk reduction measures.[74] These reviews should cover failure mechanisms including, but not limited to corrosion, environmental cracking, erosion, and mechanical damage, such as vibration induced fatigue.[75] Finally, this guidance states that a formal, documented quantitative and logic based assessment should be used when conducting corrosion reviews.[76]

77. Under a rule issued by the U.S. Environmental Protection Agency (EPA),[77] a facility with a tank, drum, pipe, or other process[i] that contains an extremely hazardous toxic or flammable substance listed at 40 CFR §68.130 in an amount above the "threshold quantity" specified for that substance, is required to conduct a hazard assessment as well as develop a prevention program and an emergency response program. These requirements are documented in a Risk Management Plan (RMP) that is submitted to EPA. Covered facilities must implement the RMP and update their RMPs periodically or when certain changes occur. The goal of EPA's Risk Management Program is to prevent accidental releases of substances that can cause serious harm to the public and the environment from short-term exposures, and to mitigate the severity of releases that do occur.[78]

78. The EPA RMP program provisions build on the planning and preparedness groundwork laid by the Emergency Planning and Community Right-to-Know Act of 1986 (EPCRA). EPCRA establishes requirements for federal, state, and local governments, as well as industry, regarding emergency planning and "Community Right-to-Know" reporting on hazardous toxic chemicals. EPCRA "help[s] increase the public's knowledge and access to information on chemicals at individual facilities, their uses, and releases into the environment."[79] According to the U.S. EPA's Chemical Emergency Preparedness and Prevention Office,[ii] transparency between industry and the public will improve community safety:

> Both EPCRA and the CAA [Clean Air Act] section 112(r) Risk Management Program encourage communication between facilities and the surrounding communities about chemical safety and chemical risks. Regulatory requirements, by themselves, will not guarantee safety from chemical accidents. Information about hazards in a community will allow local emergency officials and the public to work with industry to prevent accidents.[80]

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[i] "Process" means "any activity involving a regulated substance including any use, storage, manufacturing, handling, or on-site movement of such substances, or combination of these activities…" 40 CFR §68.3 (1997).

[ii] In 2004, the U.S. EPA's Chemical Emergency Preparedness and Prevention Office was merged with the Superfund Emergency Response Program and Oil Spill Prevention Program to form the Office of Emergency Management, or OEM. OEM works with other EPA partners, federal, state, and local agencies, and industry to prevent accidents and maintain and provide superb response capabilities. *See* http://www.epa.gov/oem/about.htm (accessed April 17, 2013).

The CCPS also notes that governments and advocacy organizations have been successful in driving performance improvement by using public disclosure to make safety information available to the public.[81]

79. Under the RMP program's hazard assessment requirement, a facility must prepare a worst-case release scenario analysis[82] and complete a five-year accident history.[83] A covered facility must also develop and implement an emergency response program that includes procedures for informing the public and local agencies about accidental releases and procedures and measures for emergency response after an accidental release.[84] Officials and the public, including local emergency planning committees (LEPCs) can use this information to understand the chemical hazards in the community and then work with industry to address and mitigate those hazards. With both EPCRA and the Risk Management Program, the regulatory purpose and substantive provisions emphasize the importance of transparency, sharing of process safety data, and public participation to prevent chemical accidents. The CSB notes that post-incident, during the decision-making related to piping repairs to the crude unit, the public, worker representatives, regulators, and governmental bodies played a key role driving transparency, accountability, and improved risk reduction.

80. Workforce involvement is a key element of process safety and effective chemical accident prevention. In the Center for Chemical Process Safety publication, *Guidelines for Risk Based Process Safety*, it lists workforce involvement as one of 20 essential management systems necessary to reduce process safety risks and prevent chemical accidents.[85] CCPS states that:

> …workers are potentially the most knowledgeable people with respect to the day-to-day details of operating the process and maintaining the equipment and facilities and may be the sole source for some types of knowledge gained through their unique experiences. Workforce involvement provides management a mechanism for tapping into this valuable expertise.[86]

This CCPS publication discusses general areas of workforce involvement in risk assessments, inspections, audits, and performance reviews. The CCPS notes that participation leads to empowerment, management responsiveness, and process safety performance improvement.[87] The OSHA PSM Standard emphasizes the importance of participation by workers and their representatives. It requires employers to develop a written plan of action, consult with employees, and make available all process safety information.[88] In previous investigation reports, the CSB has identified that workers and their representatives play a very important role in major incident prevention. For example, in the BP Texas City oil refinery investigation report, the CSB recommended that BP and the United Steelworkers International Union (USW) establish a joint program to report incidents and near misses, and to ensure that recommendations made during investigations were implemented. The CSB also recommended that API and the USW work together to develop a safety standard addressing leading and lagging process safety indicators. [i]

81. In July 2012, the CSB held a public hearing on process safety indicators[ii] to explore how companies and regulators use process safety metrics to manage risks and drive continuous safety improvements. During this hearing the CSB stated that, following the 2005 BP Texas City accident, both the CSB and Baker Panel[iii] reports noted the lack of focus by BP on process safety and inadequate performance measurement indicators. The CSB also noted that one goal of process safety indicators is to drive continuous process safety improvement, and that regulators can utilize these indicators to focus inspections, audits, and investigations.

82. Process safety management systems are critical for reducing process safety incidents. Process safety indicators are a significant element of these systems. Indicators measure the strengths and weaknesses of process safety management systems, to achieve and maintain safe and reliable operations. [89] Properly selected and managed indicators will identify the successes and point out the flaws of the system.[90]

83. In 2008, the CCPS published a guidance document for the development of leading[iv] and lagging[v] process safety indicators to assist industry in avoiding catastrophic chemical incidents.[91] While process safety indicators are an important tool for major accident prevention, the simple activity of identifying and recording process safety metrics will not drive process safety improvement. CCPS notes that these metrics must be "collected, analyzed, communicated, understood, and *acted upon.*"[92]

84. The UK HSE has published a guidance document to help chemical and major hazard industries develop process safety indicators. HSE states that:

> Most systems and procedures deteriorate over time, and system failures discovered following a major incident frequently surprise senior managers, who sincerely believed that the controls were functioning as designed. Used effectively, process

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[i] Process safety indicators are also referred to as safety performance indicators, metrics, key process indicators (KPI), performance measures, indicators, etc…

[ii] *See* http://www.csb.gov/assets/1/19/CSB_20Public_20Hearing.pdf (accessed April 17, 2013).

[iii] *See* http://www.bp.com/liveassets/bp_internet/globalbp/globalbp_uk_english/SP/STAGING/local_assets/assets/pdfs/Baker_panel_report.pdf (accessed April 12, 2013).

[iv] Leading indicators are measurements that predict future performance to ensure that safety protection layers and operating discipline are being maintained, including unsafe behaviors or insufficient operating discipline equipment selection, engineering design, specification of inspection frequency, and technique. *See* Center for Chemical Process Safety (CCPS), *Guidelines for Process Safety Metrics*, Page 20. 2010.

[v] Lagging indicators are facts about previous events, such as process safety incidents, that meet the threshold of severity and should be reported as part of the process safety metric. *See* Center for Chemical Process Safety (CCPS), "Guidelines for Process Safety Metrics," 2010; Page 20.

> safety indicators can provide an early warning, before catastrophic failure, that critical controls have deteriorated to an unacceptable level. [93]

85. The public can play an important role in monitoring safety management systems. In its recent guidelines, the CCPS promoted the sharing of process safety indicators with the public:

> Sharing performance metrics and results broadly can engage the public as a partner in holding the organization accountable for process safety performance. Making metrics and performance public can be an especially powerful way of maintaining upper management commitment since it will likely be the CEO or other senior managers who will be called to account by the public if goals are not met or performance declines. Communicating process safety successes also demonstrates to employees and the public that positive change can be, and are being, made within an organization. [94]

Recommendations

Under 42 U.S.C. 7412(r)(6)(C)(ii), the U.S. Chemical Safety and Hazard Investigation Board is charged with "recommending measures to reduce the likelihood or the consequences of incidental releases and proposing corrective steps to make chemical production, processing, handling and storage as safe and free from risk of injury as possible …." The CSB makes recommendations based on the findings and conclusions of the investigation. Recommendations are made to parties that can affect change to prevent future incidents, which may include the company, contractors, industry organizations responsible for developing good practice guidelines, regulatory bodies, and/or organizations that have the ability to broadly communicate lessons learned from the incident, such as trade associations or professional societies.

Chevron U.S.A (Urgent)

2012-03-I-CA-R1

At all Chevron U.S. refineries, engage a diverse team of qualified personnel to perform a documented damage mechanism hazard review. This review shall be an integral part of the Process Hazard Analysis cycle and shall be conducted on all PSM-covered process piping circuits and process equipment. The damage mechanism hazard review shall identify potential process damage mechanisms and consequences of failure, and shall ensure safeguards are in place to control hazards presented by those damage mechanisms. Analyze and incorporate into this review applicable industry best practices, Chevron Energy Technology Company findings and recommendations, and inherently safer systems to the greatest extent feasible.

2012-03-I-CA-R2

At all California Chevron U.S. refineries, report leading and lagging process safety indicators, such as the action item completion status of recommendations from damage mechanism hazard reviews, to the federal, state, and local regulatory agencies that have chemical release prevention authority.

Mayor and City Council,
City of Richmond, California

2012-03-I-CA-R3

Revise the Industrial Safety Ordinance (ISO) to require that Process Hazard Analyses include documentation of the recognized methodologies, rationale and conclusions used to claim that safeguards intended to control hazards will be effective. This process shall use established qualitative, quantitative, and/or semi-quantitative methods such as Layers of Protection Analysis (LOPA).

2012-03-I-CA-R4

Revise the Industrial Safety Ordinance (ISO) to require the documented use of inherently safer systems analysis and the hierarchy of controls to the greatest extent feasible in establishing safeguards for identified process hazards. The goal shall be to drive the risk of major accidents to As Low As Reasonably Practicable (ALARP). Include requirements for inherently safer systems analysis to be automatically triggered for all Management of Change and Process Hazard Analysis reviews, prior to the construction of new processes, process unit rebuilds, significant process repairs, and in the development of corrective actions from incident investigation recommendations.

2012-03-I-CA-R5

Ensure the effective implementation of the damage mechanism hazard review program (2012-03-I-CA-R1 and 2012-03-I-CA-R2), so that all necessary mechanical integrity work at the Chevron Richmond Refinery is identified and recommendations are completed in a timely way.

Board of Supervisors
Contra Costa County, California

2012-03-I-CA-R6

Revise the Industrial Safety Ordinance (ISO) to require that Process Hazard Analyses include documentation of the recognized methodologies, rationale and conclusions used to claim that safeguards intended to control hazards will be effective. This process shall use established qualitative, quantitative, and/or semi-quantitative methods such as Layers of Protection Analysis (LOPA).

2012-03-I-CA-R7

Revise the Industrial Safety Ordinance (ISO) to require the documented use of inherently safer systems analysis and the hierarchy of controls to the greatest extent feasible in establishing safeguards for identified process hazards. The goal shall be to drive the risk of major accidents to As Low As Reasonably Practicable (ALARP). Include requirements for inherently safer systems analysis to be automatically triggered for all Management of Change and Process Hazard Analysis reviews, prior to the construction of new processes, process unit rebuilds, significant process repairs, and in the development of corrective actions from incident investigation recommendations.

2012-03-I-CA-R8

Monitor and confirm the effective implementation of the damage mechanism hazard review program (2012-03-I-CA-R1 and 2012-03-I-CA-R2), so that all necessary mechanical integrity work at the Chevron Richmond Refinery is identified and recommendations are completed in a timely way.

California State Legislature,
Governor of California

2012-03-I-CA-R9

Revise the California Code of Regulations, Title 8, Section 5189, Process Safety Management of Acutely Hazardous Materials, to require improvements to mechanical integrity and process hazard analysis programs for all California oil refineries. These improvements shall include engaging a diverse team of qualified personnel to perform a documented damage mechanism hazard review. This review shall be an integral part of the Process Hazard Analysis cycle and shall be conducted on all PSM-covered process piping circuits and process equipment. The damage mechanism hazard review shall identify potential process damage mechanisms and consequences of failure, and shall ensure safeguards are in place to control hazards presented by those damage mechanisms. Require the analysis and incorporation of applicable industry best practices and inherently safety systems to the greatest extent feasible into this review.

2012-03-I-CA-R10

For all California oil refineries, identify and require the reporting of leading and lagging process safety indicators, such as the action item completion status of recommendations from damage mechanism hazard reviews, to state and local regulatory agencies that have chemical release prevention authority. These indicators shall be used to ensure that requirements described in 2012-03-I-CA-R9 are effective at improving mechanical integrity and process hazard analysis performance at all California oil refineries and preventing major chemical incidents.

2012-03-I-R11

Establish a multi-agency process safety regulatory program for all California oil refineries to improve the public accountability, transparency, and performance of chemical accident prevention and mechanical integrity programs. This program shall:

1. Establish a system to report to the regulator the recognized methodologies, findings, conclusions and corrective actions related to refinery mechanical integrity inspection and repair work arising from Process Hazard Analyses, California oil refinery turnarounds and maintenance-related shutdowns;
2. Require reporting of information such as damage mechanism hazard reviews, notice of upcoming maintenance-related shutdowns, records related to proposed and completed mechanical integrity work lists, and the technical rationale for any delay in work proposed but not yet completed;

3. Establish procedures for greater workforce and public participation including the public reporting of information; and
4. Provide mechanisms for federal, state and local agency operational coordination, sharing of data (including safety indicator data), and joint accident prevention activities. The California Department of Industrial Relations will be designated as the lead state agency for establishing a repository of joint investigative and inspection data, coordinating the sharing of data and joint accident prevention activities.

2012-03-I-CA-R12

Require that Process Hazard Analyses required under California Code of Regulations, Title 8, Section 5189 Section (e) include documentation of the recognized methodologies, rationale and conclusions used to claim that safeguards intended to control hazards will be effective. This process shall use established qualitative, quantitative, and/or semi-quantitative methods such as Layers of Protection Analysis (LOPA).

2012-03-I-CA-R13

Require the documented use of inherently safer systems analysis and the hierarchy of controls to the greatest extent feasible in establishing safeguards for identified process hazards. The goal shall be to drive the risk of major accidents to As Low As Reasonably Practicable (ALARP). Include requirements for inherently safer systems analysis to be automatically triggered for all Management of Change and Process Hazard Analysis reviews, prior to the construction of new process, process unit rebuilds, significant process repairs and in the development of corrective actions from incident investigation recommendations.

2012-03-I-CA-R14

Monitor and confirm the effective implementation of the damage mechanism hazard review program (2012-03-I-CA-R9 and 2012-03-I-CA-R10), so that all necessary mechanical integrity work at all California Chevron Refineries is identified and recommendations are completed in a timely way.

The U.S. Environmental Protection Agency

2012-03-I-CA-R15

Jointly plan and conduct inspections with Cal/OSHA, California EPA and other state and local regulatory agencies with chemical accident prevention responsibilities to monitor the effective implementation of the damage mechanism hazard review and disclosure requirements under 2012-03-I-CA-R9 and R10 above.

The Board of Supervisors, Contra Costa County, California, 2012-03-I-CA-R16;
The Mayor and City Council, City of Richmond, California, 2012-03-I-CA-R17;
The California Air Quality Management Divisions, 2012-03-I-CA-R18;
The U.S. Environmental Protection Agency, 2012-03-I-CA-R19; and
The California Environmental Protection Agency, 2012-03-I-CA-R20;

Participate in the joint regulatory program described in recommendation 2012-03-I-CA-R11. This participation shall include contributing relevant data to the repository of investigation and inspection data created by the California Department of Industrial Relations and jointly coordinating activities.

Additional Issues Currently Under Investigation

The following section highlights additional issues which the CSB has identified to date in its investigation of the Chevron Richmond Refinery fire and major hydrocarbon release that occurred on August 6, 2012. These issues relate to the ongoing CSB investigation of the management and regulation of health and safety at refineries. The CSB final report will make additional recommendations consistent with this interim report and will present additional detailed findings and analyses in a final report on the incident, to be released later in 2013.

Regulatory Oversight

The CSB noted in its BP Texas City (BPTC) Final Investigation Report (issued in March 2007) the importance of having a well-resourced, competent regulator consisting of individuals with the necessary training, education, and experience to conduct planned comprehensive and robust inspections of facilities with the goal of preventing catastrophic accidents. In a 1992 compliance directive[i] the federal Occupational Safety and Health Administration (OSHA) stated that the primary enforcement model for the Process Safety Management of Highly Hazardous Chemicals (PSM) standard would be planned, comprehensive, and resource-intensive Program Quality Verification (PQV) inspections to help prevent catastrophic accidents.[95] However, the CSB report noted that for the 10-year period prior to the Texas City incident, federal OSHA had conducted no planned PQV inspections in oil refineries. Regular planned inspections appropriately emphasize the prevention of accidents that are potentially catastrophic. Issuing fines and prosecuting companies post-incident are not acceptable substitutes for prevention. As a result, CSB recommended in its report that OSHA strengthen the planned enforcement of the OSHA Process Safety Management (PSM) standard by developing more highly trained and experienced inspectors to conduct more comprehensive inspections similar to those under OSHA's PQV program at facilities presenting the greatest risk of a catastrophic accident.

Spurred in part by the CSB's recommendations, OSHA issued the Petroleum Refinery Process Safety Management National Emphasis Program (NEP) on June 7, 2007.[ii] The NEP was a federal program that established guidelines for inspecting petroleum refineries to assure compliance with the PSM standard, 29 CFR §1910.119.[96] Unlike the PQV approach to inspections, which "employs a broad, open-ended inspection strategy and uses a more global approach to identify compliance deficiencies…,"[97] the NEP "provide[d] a specific tool to evaluate compliance with the [PSM] standard…[which] identifies a particular set of requirements from the PSM standard from which CSHOs [Compliance Safety and Health Officers] are to review documents, interview employees, and verify implementation for specific processes, equipment, and procedures."[98] While the CSB called for an ongoing comprehensive inspection

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[i] Compliance directives are the main method OSHA uses to communicate plans, inspection methods, and compliance expectations to their Compliance Safety and Health Officers (CSHOs) for enforcing a new regulation.

[ii] Originally Directive Number CPL 03-00-004. Extended August 18, 2099 as Directive Number CPL 03-00-010 to allow more time to complete NEP inspections under the original CPL 03-00-004.

program, inspections being conducted pursuant to the NEP were terminated in 2011. The CSB recommendation to OSHA remains Open.[i]

OSHA State Plan States[ii] were strongly encouraged but not required to implement the NEP. California's Division of Occupational Safety and Health (Cal/OSHA) did not adopt the NEP "because of its dedicated PSM Unit."[99] Cal/OSHA informed the CSB that federal OSHA approved this decision in 2007. In lieu of conducting NEP inspections, Cal/OSHA's PSM Unit has conducted and continues to conduct a full range of programmed, accident, complaint, and referral inspections of PSM-covered facilities in the state of California pursuant to the California Labor Code, Title 8 regulations, and Cal/OSHA's Policy and Procedures (P&P) Manual C-17 "Process Safety Management,"[iii] to ensure these facilities are complying with PSM requirements.

Between 2006 and August 6, 2012, Cal/OSHA conducted three planned inspections of the Chevron Richmond facility, totaling only 150 inspector hours of effort. None of these inspections resulted in citations or fines. In contrast, according to statistics provided by OSHA, federal NEP refinery inspections conducted between 2007 and the end of 2011 lasted roughly 1,000 inspector hours each and resulted in an average of 11.2 violations and $76,821 in penalties per inspection. OSHA noted that hours spent on a typical federal refinery NEP inspection were 40 times greater than the average OSHA inspection. These numbers indicate a major disparity in thoroughness and comprehensiveness between the planned inspections conducted by Cal/OSHA and the NEP inspections conducted by OSHA and other OSHA State Plan States.

The safety case is a rigorous prescriptive and goal-setting regulatory regime that is highlighted by its adaptability and requirements for continuous improvements in risk reduction for high hazard industrial facilities. The approach is used widely overseas but is not used currently for U.S. process industries. The CSB is currently examining whether the implementation of the safety case regime could be a more effective regulatory tool for Cal/OSHA in its effort to ensure that California refineries are identifying and controlling hazards and ultimately driving risk to as low as reasonably practicable (ALARP). Utilizing the safety case requires effective implementation by an independent, competent, well-funded regulator. Experience and competence of the regulator in technical areas such as chemical engineering, human factors, and process safety are necessary to provide effective auditing and regulatory oversight for prevention. To ensure effective implementation of the safety case, industry standards and guidelines must be rigorous and up-to-date as well. The CSB notes that relevant and applicable industry standards and guidelines – such as API RP 939-C – currently contain voluntary and permissive language. The CSB will be examining the need for more effective good practice standards and guidelines containing the necessary requirements to prevent catastrophic accidents.

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[i] Open - Awaiting Response or Evaluation/Approval of Response (O - ARE/AR) - The recipient has not submitted a substantive response, or the evaluation by CSB staff of a response is pending, or the Board has not yet acted on staff recommendation of status.

[ii] Section 18 of the Occupational Safety and Health Act of 1970 encourages States to develop and operate their own job safety and health programs, referred to informally as an OSHA State Plan. OSHA approves and monitors State plans and provides up to 50 percent of an approved plan's operating costs.

[iii] Issued June 6, 1994. Revised August 1, 1994 and May 19, 2007.

In addition to the issues discussed above, the CSB will also be examining the need for the reporting of leading and lagging process safety indicators to the regulator; the regulator's effective use of these process safety indicators; workforce and stakeholder involvement in regulatory oversight of refineries; and the thoroughness of Contra Costa County's safety auditing of the Chevron facility.

Emergency Planning and Reporting

According to information provided by Contra Costa Emergency Medical Services, 15,213 individuals sought emergency medical attention between August 6 and August 23, 2012, due to the Chevron refinery major hydrocarbon release and fire.

CSB Investigation Team members visited local hospitals the week of the incident to better understand the impact on the surrounding community. Officials at Doctor's Medical Center (DMC) in San Pablo, California, informed the CSB that in the days following the incident they were inundated with emergency room visits and found it difficult to handle the influx due to a lack of funding and staffing. Officials at both DMC and Kaiser Permanente Hospital (KP) in Richmond told the CSB that they lacked specific knowledge of the chemicals released as a result of the incident, complicating efforts to evaluate and treat individuals.

The California Code of Regulations (CCR) requires that owners and operators of hazardous waste facilities make "arrangements to familiarize local hospitals with the properties of hazardous waste handled at the facility and the types of injuries or illnesses which could results from fires, explosions, or releases at the facility."[100] The CSB is currently evaluating ways to ensure that hospitals have the information necessary to properly evaluate and treat individuals that may be exposed to releases from facilities in Contra Costa County.

Following the incident, Contra Costa County's Community Warning System (CWS) notified the surrounding community of a hazardous material incident and ordered a shelter-in-place (SIP). The CWS uses sirens, the news media, and phone calls to residents in order to initiate the SIP. Contra Costa County issued the SIP on August 6, 2012, at 6:38 pm for the cities of Richmond, San Pablo, and North Richmond, California, and lifted the SIP later that evening at 11:12 pm. However, the CSB has learned that some phone calls notifying residents of the SIP did not occur until over four hours after the release.

It is essential that responders, community residents, and hospitals in the areas surrounding industrial facilities be aware of what hazardous materials exist at these facilities, what specific chemicals are released into the community in the event of an incident, and what is known about the potential acute and chronic health impacts. The CSB will be analyzing ways to strengthen current regulations and policies to ensure there is proper emergency planning and reporting for industrial facilities in Contra Costa County and the state of California.

Emergency Response

OSHA provides guidance on emergency response in its *Hazardous Waste Operations and Emergency Response* standard, known as HAZWOPER, under 29 CFR §1910.120 (p) and (q). Under 29 CFR §1910.120(q)(6), the HAZWOPER standard contains requirements for training and qualification of all individuals involved in emergency response related to their roles and responsibilities.

Good safety practice dictates that individuals responding to emergencies should have the technical knowledge to give input into shutdown decisions, set up an incident command structure, establish boundary limits, and evaluate the "hot zone." Access to the hot zone must be strictly limited to personnel with higher degrees of specific training, experience, and appropriate personal protective equipment; all others must be removed to a safe location away from chemical hazards. Hot zone boundaries must be established to anticipate the possible escalation of releases and the positioning of firefighting equipment such as fire trucks.

The CSB will be looking at the sufficiency of regulatory requirements, industry standards, and good practices, in addition to evaluating emergency response decision-making following the leak and subsequent pipe rupture (including the training and qualification of responders) to determine whether improvements are needed in these areas.

Safety Culture

The Center for Chemical Process Safety (CCPS) defines process safety culture as the "combination of group values and behaviors that determines the manner in which process safety is managed."[101] As the CSB noted in its BP Texas City Report, safety culture can be influenced by management changes, historical events, and economic pressures. After reviewing evidence and decisions made relating to materials of construction and mechanical integrity within the crude unit at the Chevron refinery, as well as the response to the leak on August 6, 2012, the CSB has determined that issues relating to safety culture are relevant to this incident. The CSB will examine the Chevron Richmond Refinery's approach to safety, its safety culture and any organizational deficiencies, to determine how to best prevent future incidents.

The CSB notes that on August 6, 2012, following discovery of the leak on the 4-sidecut piping, Chevron hoped to forestall a shutdown by installing a leak repair clamp.[i] Chevron's mechanical integrity management system has not been fully successful in detecting and replacing deteriorated piping components prior to failure, resulting in the company's frequent use of leak repair clamps[ii] to externally stop process fluid leaks. Chevron's reliance on such clamps to mitigate process piping component leaks identifies serious questions about its mechanical integrity program. The CSB determined that Chevron

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[i] Chevron's leak repair clamp vendor was called out to the scene of the leak to help determine potential clamping options.

[ii] Leak repair clamps are mechanical devices designed and installed to stop a leak from a piping component such as piping, valves, flanges, and instrumentation. These devices are typically intended to provide a temporary repair while a process continues operation until a plant shutdown takes place and a permanent repair can be made.

has more than 100 clamps on hydrocarbon and other process piping components at the Richmond refinery. The leak repair clamp is typically relied upon to prevent further leaking until the next unit turnaround, when the deteriorated piping component can be repaired. However, Cal/OSHA citations following the August 6, 2012, fire in the crude unit identified that Chevron has not always replaced these clamps during unit turnarounds and these devices then remain in service significantly longer than originally intended. The CSB determined that Chevron has leak repair clamps in place on piping components containing hazardous flammable process fluids including applications where the process material is above the autoignition temperature. Some of these leak repair clamp applications are in locations where a permanent repair would not have required a unit shutdown. The CSB will further evaluate the frequent use of leak repair clamps by Chevron and the potential that the deviance of a weak mechanical integrity management system has been normalized.[i]

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[i] Normalization of deviance is a long-term phenomenon in which individuals or work teams gradually accept a lower standard of performance until the lower standard becomes the norm. It is typically the result of conditions slowly changing and eroding over time. *See* Center for Chemical Process Safety (CCPS), Recognizing Catastrophic Incident Warning Signs in the Process Industries, Page 4. 2012.

BY THE

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Date of Approval April __, 2013.

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INVESTIGATION REPORT

REFINERY FIRE INCIDENT

(4 Dead, 1 Critically Injured)

TOSCO AVON REFINERY

MARTINEZ, CALIFORNIA
FEBRUARY 23, 1999

KEY ISSUES:

- CONTROL OF HAZARDOUS NONROUTINE MAINTENANCE
- MANAGEMENT OVERSIGHT AND ACCOUNTABILITY
- MANAGEMENT OF CHANGE
- CORROSION CONTROL

REPORT NO. 99-014-I-CA
ISSUE DATE: MARCH 2001

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Abstract

This investigation report examines the refinery fire incident that occurred on February 23, 1999, in the crude unit at the Tosco Corporation Avon refinery in Martinez, California. Four workers were killed, and one was critically injured. This report identifies the root and contributing causes of the incident and makes recommendations for control of hazardous nonroutine maintenance, management oversight and accountability, management of change, and corrosion control.

The U.S. Chemical Safety and Hazard Investigation Board (CSB) is an independent Federal agency whose mission is to ensure the safety of workers and the public by preventing or minimizing the effects of chemical incidents. CSB is a scientific investigative organization; it is not an enforcement or regulatory body. Established by the Clean Air Act Amendments of 1990, CSB is responsible for determining the root and contributing causes of accidents, issuing safety recommendations, studying chemical safety issues, and evaluating the effectiveness of other government agencies involved in chemical safety. No part of the conclusions, findings, or recommendations of CSB relating to any chemical incident may be admitted as evidence or used in any action or suit for damages arising out of any matter mentioned in an investigation report (see 42 U.S.C. § 7412(r)(6)(G)). CSB makes public its actions and decisions through investigation reports, summary reports, safety bulletins, safety recommendations, special technical publications, and statistical reviews. More information about CSB may be found on the World Wide Web at http://www.chemsafety.gov.

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For this report, refer to NTIS number PB2001-104050.

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Acronyms and Abbreviations

AIChE	American Institute of Chemical Engineers
API	American Petroleum Institute
Cal/OSHA	California Department of Industrial Relations, Division of Occupational Safety and Health
CCPS	Center for Chemical Process Safety
CFR	Code of Federal Regulations
CSB	U.S. Chemical Safety and Hazard Investigation Board
EPA	U.S. Environmental Protection Agency
°F	Degrees Fahrenheit
HAZOP	Hazard and operability
HSE	Health and Safety Executive (United Kingdom)
ICE	Institution of Chemical Engineers (United Kingdom)
LCV	Level control valve
MOC	Management of change
MSDS	Material Safety Data Sheet
NFPA	National Fire Protection Association
NPRA	National Petrochemical & Refiners Association
NTIS	National Technical Information Service
NTSB	National Transportation Safety Board
OSHA	Occupational Safety and Health Administration
PACE	Paper, Allied-Industrial, Chemical & Energy Workers International Union
psig	Pounds per square inch gage
PPE	Personal protective equipment
PSM	Process safety management
SCBA	Self-contained breathing apparatus
UDS	Ultramar Diamond Shamrock Corporation
U.S.C.	United States Code

Executive Summary

ES.1 Introduction

On February 23, 1999, a fire occurred in the crude unit at Tosco Corporation's Avon oil refinery in Martinez, California. Workers were attempting to replace piping attached to a 150-foot-tall fractionator[1] tower while the process unit was in operation. During removal of the piping, naphtha[2] was released onto the hot fractionator and ignited. The flames engulfed five workers located at different heights on the tower. Four men were killed, and one sustained serious injuries.

Ultramar Diamond Shamrock Corporation (UDS) purchased the facility in September 2000 and renamed it the Golden Eagle refinery.

Because of the serious nature of this incident, and the fact that another fatality had occurred at the Avon facility in 1997, the U.S. Chemical Safety and Hazard Investigation Board (CSB) initiated an investigation to determine the root and contributing causes of the incident and to issue recommendations to help prevent similar occurrences.

ES.2 Incident

On February 10, 1999, a pinhole leak was discovered in the crude unit on the inside of the top elbow of the naphtha piping, near where it was attached to the fractionator at 112 feet above grade.[3] Tosco personnel responded immediately, closing four valves in an attempt to isolate the piping. The unit remained in operation.

Subsequent inspection of the naphtha piping showed that it was extensively thinned and corroded. A decision was made to replace a large section of the naphtha line.[4] Over the 13 days between the discovery of the leak and the fire, workers made numerous

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[1] A fractionator is an oil refinery processing vessel that separates preheated hydrocarbon mixtures into various components based on boiling point. The separated components are referred to as fractions or cuts. Inside the fractionator, some trays draw off the fractions as liquid hydrocarbon products (such as naphtha), and piping transports them to storage or for further processing.

[2] Petroleum naphtha is a highly flammable mixture of liquid hydrocarbons drawn off as a cut from the fractionator tower.

[3] "Above grade" refers to the vertical distance from ground level at the point upon which equipment rests.

[4] The term "naphtha line" is synonymous with naphtha piping. "Naphtha draw line" was also used at the facility to refer to the naphtha piping. The draw line takes or "draws" naphtha product from the 38th tray of the fractionator, where it flows through a level control valve to the naphtha stripper vessel.

unsuccessful attempts to isolate and drain the naphtha piping. The pinhole leak reoccurred three times, and the isolation valves were retightened in unsuccessful efforts to isolate the piping. Nonetheless, Tosco supervisors proceeded with scheduling the line replacement while the unit was in operation.

On the day of the incident, the piping contained approximately 90 gallons of naphtha, which was being pressurized from the running process unit through a leaking isolation valve. A work permit authorized maintenance employees to drain and remove the piping. After several unsuccessful attempts to drain the line, a Tosco maintenance supervisor directed workers to make two cuts into the piping using a pneumatic saw.[5] After a second cut began to leak naphtha, the supervisor directed the workers to open a flange[6] to drain the line. As the line was being drained, naphtha was suddenly released from the open end of the piping that had been cut first. The naphtha ignited, most likely from contacting the nearby hot surfaces of the fractionator, and quickly engulfed the tower structure and personnel.

ES.3 Key Findings

1. The removal of the naphtha piping with the process unit in operation involved significant hazards. This nonroutine[7] work required removing 100 feet of 6-inch pipe containing naphtha, a highly flammable liquid. Workers conducting the removal were positioned as high as 112 feet above ground, with limited means of escape. The hot process unit provided multiple sources of ignition, some as close as 3 feet from the pipe removal work. One isolation valve could not be fully closed, which indicated possible plugging.

   On three occasions prior to the incident, the naphtha pipe resumed leaking from the original pinhole and felt warm to the

The hot process unit provided multiple sources of ignition, some as close as 3 feet from the pipe removal work.

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[5] A pneumatic saw is a cutting device that is energized by air pressure rather than electrical energy.

[6] A flange is a rim on the end of a section of piping or equipment used for attachment to other piping and equipment.

[7] The Center for Chemical Process Safety (CCPS) defines "nonroutine work" as unscheduled maintenance work that necessitates immediate repair and may introduce additional hazards (CCPS, 1995b; p. 212). One example is "breakdown maintenance," where equipment is operated until it fails. In this incident, the February 10 naphtha draw line leak is an example of breakdown maintenance.

touch, indicating that one or more isolation valves were leaking. Numerous attempts to drain the piping were unsuccessful; a failed attempt to ream out the drain lines and the removal of a small section of pipe confirmed that the line was extensively plugged. On seven occasions, the downstream naphtha stripper vessel filled–indicating probable isolation valve leakage.

2. The naphtha pipe that was cut open during the repair work was known by workers and the maintenance supervisor to contain flammable liquid. Although Tosco procedures required piping to be drained, depressured, and flushed prior to opening,[8] this was not accomplished because extensive plugging prevented removal of the naphtha. The procedures did not specify an alternative course of action if safety preconditions, such as draining, could not be met. Although the hot process equipment was close to the removal work, Tosco's procedures and safe work permit did not identify ignition sources as a potential hazard. The permit also failed to identify the presence of hazardous amounts of benzene in the naphtha.

3. The naphtha stripper vessel level control bypass valve was leaking, which prevented isolation of the line from the operating process unit. As a result, the running unit pressurized the naphtha piping. Excessive levels of corrosive material and water in the naphtha line and operation of the bypass valve in the partially open position for prolonged periods led to erosion/corrosion of the valve seat and disk. Excessive levels of corrosives and water also produced plugging in the piping and led to the initial leak.

4. Tosco's job planning procedures did not require a formal evaluation of the hazards of replacing the naphtha piping. The pipe repair work was classified as low risk maintenance. Despite serious hazards caused by the inability to drain and isolate the line–known to supervisors and workers during the week prior to the incident–the low risk classification was not reevaluated, nor did management formulate a plan to control the known hazards.

Despite serious hazards caused by the inability to drain and isolate the line–known to supervisors and workers during the week prior to the incident–the low risk classification was not reevaluated, nor did management formulate a plan to control the known hazards.

5. Tosco's permit for the hazardous nonroutine work was authorized solely by a unit operator on the day of the incident. Operations

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[8] Tosco Avon Safety Procedure S-5, Safety Orders, Departmental Safe Work Permits, October 19, 1998.

supervisors were not involved in inspecting the job site or reviewing the permit.

6. Operations supervisors and refinery safety personnel were seldom present in the unit to oversee work activities. On the morning of the incident, prior to the fire, one operations supervisor briefly visited the unit, but he did not oversee the work in progress and no safety personnel visited the unit. The maintenance supervisor was the only management representative present during the piping removal work.

   The U.S. Environmental Protection Agency (EPA) similarly determined that a lack of operations supervisory oversight during safety critical activities was one of the causes of a previous Avon refinery incident, a 1997 explosion and fire at the hydrocracker, which resulted in one fatality (USEPA, 1998; pp. viii, 65).[9]

In the 3 years prior to the incident, neither Tosco's corporate safety group nor Avon facility management conducted documented audits of the refinery's line breaking, lockout/tagout, or blinding procedures and practices.

7. In the 3 years prior to the incident, neither Tosco's corporate safety group nor Avon facility management conducted documented audits of the refinery's line breaking,[10] lockout/tagout,[11] or blinding[12] procedures and practices.

8. Tosco did not perform a management of change (MOC)[13] review to examine potential hazards related to process changes, including operating the crude desalter[14] beyond its design parameters, excessive water in the crude feedstock,[15] and

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[9] The EPA report states: "Supervision was not present at the unit even though there had been a succession of operating problems just prior to the final temperature excursion that led to the explosion and fire."

[10] "Line breaking" refers to equipment opening.

[11] "Lockout/tagout" refers to a program to control hazardous energy during the servicing and maintenance of machinery and equipment. Lockout refers to the placement of a locking mechanism on an energy-isolating device, such as a valve, so that the equipment cannot be operated until the mechanism is removed. Tagout refers to the secure placement of a tag on an energy-isolating device to indicate that the equipment cannot be operated until the tag is removed.

[12] A blind is a piping component consisting of a solid metal plate inserted to secure isolation.

[13] Management of change is a systematic method for reviewing the safety implications of modifications to process facilities, process material, organizations, and standard operating practices.

[14] The desalter vessel removes inorganic salts, water, and suspended solids to reduce corrosion, plugging, and fouling of piping and equipment.

[15] Feedstock is material of varying constituents that is processed in a refinery.

prolonged operation of the bypass valve in the partially open position. Tosco memos and incident reports revealed that management recognized these operational problems and the increased rate of corrosion. However, corrective actions were not implemented in time to prevent plugging and excessive corrosion in the naphtha piping.

ES.4 Root Causes

1. **Tosco Avon refinery's maintenance management system did not recognize or control serious hazards posed by performing nonroutine repair work while the crude processing unit remained in operation.**

    - Tosco Avon management did not recognize the hazards presented by sources of ignition, valve leakage, line plugging, and inability to drain the naphtha piping. Management did not conduct a hazard evaluation[16] of the piping repair during the job planning stage. This allowed the execution of the job without proper control of hazards.
    - Management did not have a planning and authorization process to ensure that the job received appropriate management and safety personnel review and approval. The involvement of a multidisciplinary team in job planning and execution, along with the participation of higher level management, would have likely ensured that the process unit was shut down to safely make repairs once it was known that the naphtha piping could not be drained or isolated.
    - Tosco did not ensure that supervisory and safety personnel maintained a sufficient presence in the unit during the execution of this job. Tosco's reliance on individual workers to detect and stop unsafe work was an ineffective substitute for management oversight of hazardous work activities.
    - Tosco's procedures and work permit program did not require that sources of ignition be controlled prior to opening equipment that might contain flammables, nor did it specify what

The involvement of a multidisciplinary team in job planning and execution, along with the participation of higher level management, would have likely ensured that the process unit was shut down to safely make repairs once it was known that the naphtha piping could not be drained or isolated.

Tosco's reliance on individual workers to detect and stop unsafe work was an ineffective substitute for management oversight of hazardous work activities.

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[16] A hazard evaluation is a formal analytical tool used to identify and examine potential hazards connected with a process or activity (CCPS, 1992; p. 7).

actions should be taken when safety requirements such as draining could not be accomplished.

2. **Tosco's safety management oversight system did not detect or correct serious deficiencies in the execution of maintenance and review of process changes at its Avon refinery.**

   Neither the parent Tosco Corporation nor the Avon facility management audited the refinery's line breaking, lockout/tagout, or blinding procedures in the 3 years prior to the incident. Periodic audits would have likely detected and corrected the pattern of serious deviations from safe work practices governing repair work and operational changes in process units. These deviations included practices such as:

   - Opening of piping containing flammable liquids prior to draining.
   - Transfer of flammable liquids to open containers.
   - Inconsistent use of blind lists.
   - Lack of supervisory oversight of hazardous work activities.
   - Inconsistent use of MOC reviews for process changes.

ES.5 Contributing Causes

1. **Tosco Avon refinery management did not conduct an MOC review of operational changes that led to excessive corrosion rates in the naphtha piping.**

   Management did not consider the safety implications of process changes prior to their implementation, such as:

   - Running the crude desalter beyond its design parameters.
   - Excessive water in the crude feed.
   - Prolonged operation of the naphtha stripper level control bypass valve in the partially open position.

   These changes led to excessive corrosion rates in the naphtha piping and bypass valve, which prevented isolation and draining of the naphtha pipe.

2. **The crude unit corrosion control program was inadequate.**

   Although Avon refinery management was aware that operational problems would increase corrosion rates in the naphtha line, they did not take timely corrective actions to prevent plugging and excessive corrosion in the piping.

ES.6 Recommendations

Tosco Corporation

Conduct periodic safety audits of your oil refinery facilities in light of the findings of this report. At a minimum, ensure that:

- Audits assess the following:
  - ▲ Safe conduct of hazardous nonroutine maintenance
  - ▲ Management oversight and accountability for safety
  - ▲ Management of change program
  - ▲ Corrosion control program.
- Audits are documented in a written report that contains findings and recommendations and is shared with the workforce at the facility.
- Audit recommendations are tracked and implemented.

Ultramar Diamond Shamrock Golden Eagle Refinery

1. Implement a program to ensure the safe conduct of hazardous nonroutine maintenance. At a minimum, require that:
   - A written hazard evaluation is performed by a multidisciplinary team and, where feasible, conducted during the job planning process prior to the day of job execution.
   - Work authorizations for jobs with higher levels of hazards receive higher levels of management review, approval, and oversight.

- A written decision-making protocol is used to determine when it is necessary to shut down a process unit to safely conduct repairs.
- Management and safety personnel are present at the job site at a frequency sufficient to ensure the safe conduct of work.
- Procedures and permits identify the specific hazards present and specify a course of action to be taken if safety requirements–such as controlling ignition sources, draining flammables, and verifying isolation–are not met.
- The program is periodically audited, generates written findings and recommendations, and implements corrective actions.

2. Ensure that MOC reviews are conducted for changes in operating conditions, such as altering feedstock composition, increasing process unit throughput, or prolonged diversion of process flow through manual bypass valves.
3. Ensure that your corrosion management program effectively controls corrosion rates prior to the loss of containment or plugging of process equipment, which may affect safety.

American Petroleum Institute (API)
Paper, Allied-Industrial, Chemical & Energy Workers International Union (PACE)
National Petrochemical & Refiners Association (NPRA)

Communicate the findings of this report to your membership.

1.0 Introduction

1.1 Background

On February 23, 1999, a fire occurred in the crude unit at the Tosco Avon oil refinery in Martinez, California. Workers were attempting to replace piping attached to a 150-foot-tall fractionator tower while the process unit was in operation. During removal of the piping, naphtha was released onto the hot fractionator and ignited. The flames engulfed five workers located at different heights on the tower. Four of the workers died, and the fifth was seriously injured. Three of the deceased were contractors–two were employed by a scaffold erection company, and the other worked for a crane company. The fourth fatality and the worker injured were Tosco maintenance employees.

Because of the seriousness of the incident and the fact that there had been a fatal explosion and fire at the refinery 26 months earlier, the U.S. Chemical Safety and Hazard Investigation Board (CSB) launched an investigation to determine the root and contributing causes and to issue recommendations to help prevent similar occurrences.

1.2 Investigative Process

CSB was one of three governmental agencies that investigated the incident. The California Department of Industrial Relations, Division of Occupational Safety and Health (Cal/OSHA), and the Contra Costa County Health Services Department also conducted investigations.[1] The CSB incident investigation team coordinated and shared information with these two agencies.

CSB examined physical evidence at the site, conducted interviews, and reviewed relevant documents (such as a report authored by FTI Anamet (1999), prepared for Cal/OSHA, entitled *Metallurgical Evaluation of Naphtha Draw Line/Valve and Analyses of Petroleum*

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[1] Through the Department of Industrial Relations, Division of Occupational Safety and Health (Cal/OSHA), California administers its own workplace safety and health program according to provisions of the Federal Occupational Safety and Health Act of 1970 (see 29 CFR 1910). On January 15, 1999, Contra Costa County enacted an Industrial Safety Ordinance to "prevent and reduce the probability of accidental releases of regulated substances that have the potential to cause significant harm to the public health" (Contra Costa County Ordinance Code, Ordinance No. 98-48, Section 1). The ordinance includes a risk management program, a human factors program, and a root cause analysis and incident investigation program. The human factors program was not in effect at the time of the incident. Contra Costa Health Services produced a report on the incident, entitled *Investigation Into the Causes of the Fire of February 23, 1999, at No. 50 Crude Unit, Tosco Avon Refinery.*

Samples From a Crude Unit at the Tosco Avon Refinery). CSB also contracted with The Hendrix Group in Houston, Texas, for assistance with corrosion and mechanical integrity analysis. The American Petroleum Institute (API) and the National Petrochemical & Refiners Association (NPRA) provided good practice information on the safe performance of maintenance work in oil refineries. In response to a CSB request, these two organizations produced a report entitled *Work Authorization in Refineries* (API/NPRA, 2000).

1.3 Tosco Avon Oil Refinery Facility

The Avon refinery is located on a 2,300-acre site near the town of Martinez in Contra Costa County, California. The refinery has been in operation for more than 80 years; its main products are motor fuels such as gasoline and diesel. Tosco Corporation operated the Avon facility from 1976-2000, when it was purchased by Ultramar Diamond Shamrock (UDS) and renamed the Golden Eagle refinery. Tosco is the nation's largest independent refiner of petroleum products and operates seven refineries across the United States.

1.4 Crude Fractionator and Naphtha System

1.4.1 Fractionator

The Avon facility refined crude oil[2] into motor fuels; other products included propane, butane, and fuel oils. The crude unit, or 50 Unit,[3] was originally designed and built in 1946, and had undergone several major capital improvements.

Crude oil fractionation is the initial step in the refining process. It involves splitting crude oil into portions with similar boiling points. The oil is distilled into streams, including natural gasoline, naphtha,

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[2] Crude oil is a complex mixture of hydrocarbons that varies in composition, quality, and appearance from one producing field to another.

[3] The crude unit where the incident occurred was also referred to as the "50 Unit."

kerosene, diesel, and a heavy oil used as feed for the cracking unit. A series of trays inside the fractionator functions in part to condense the hydrocarbons; in some cases, the trays are used to draw off liquid products from the tower. Processing is continuous. A steady flow of crude oil is pumped into the unit, while the product and feedstock streams are continuously pumped to tanks or other refinery units for further processing.

1.4.2 Naphtha System

At the Avon refinery, naphtha was removed from a tray near the top of the fractionator (112-foot level) into 6-inch steel piping. The naphtha flowed through the piping and a level control valve, and then into the naphtha stripper (Figure 1). From there, it was pumped to storage and the reformer unit for further processing.

In prior years, the stripper had been used to remove lighter hydrocarbons from the naphtha. This practice had been discontinued at the time of the February 23 incident. However, the vapor return line remained in place.

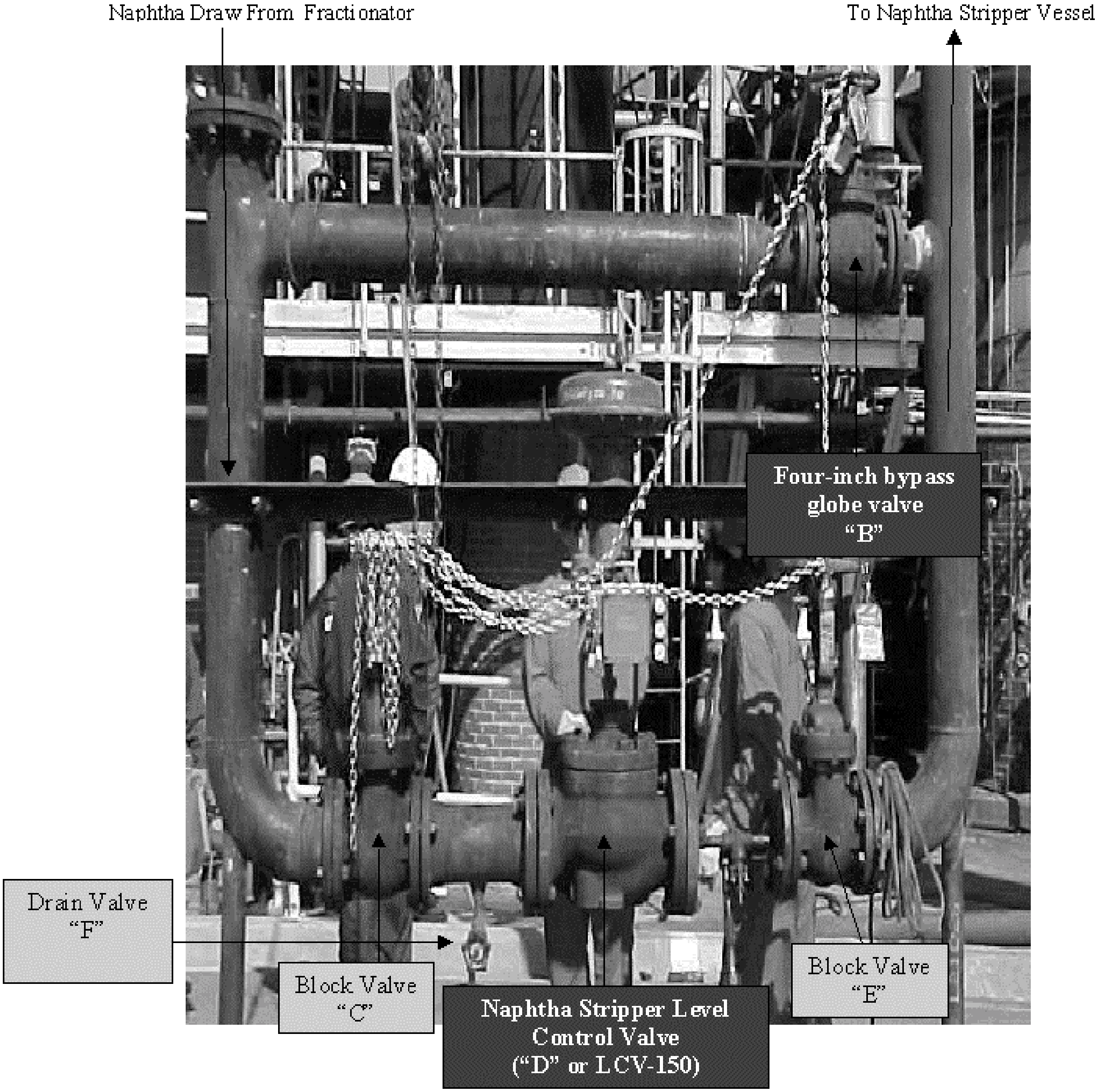

Figure 1. Naphtha stripper level control valve manifold removed to ground level.
The valve at the top right of manifold is the 4-inch bypass valve.

2.0 Description of Incident

The Incident Timeline in Appendix A summarizes the sequence of activities that led to the fire on February 23, 1999.

2.1 Pre-Incident Events

2.1.1 Detection of Naphtha Piping Leak

On February 10, the crude unit was operating routinely when a pinhole leak was detected in the upper section of the naphtha piping. From the ground, the leak was observed to be small and dripping naphtha from the line through the insulation and onto a deck on the fractionator.

2.1.2 Emergency Response and Inspection

Emergency responders decided to attempt to isolate the line to slow or stop the pinhole leak without shutting down the process unit. Operators lowered the pressure in the fractionator and diverted liquid from the naphtha tray. Personnel then donned firefighting "bunker gear"[4] and SCBAs,[5] and closed the block valve (valve A; unless otherwise noted, all valve and flange locations referenced in Section 2.0 are shown in Figure 2). Operators closed the naphtha stripper level control bypass valve (valve B) and two block valves (valves C and E).

Later in the day, the operations supervisor[6] generated an emergency work order. Over the next 13 days, 15 work permits were written for

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[4] Bunker gear is flame- and heat-resistant clothing.

[5] Self-contained breathing apparatus (SCBA) is respiratory protection worn when the breathable atmosphere may be dangerous to life or health.

[6] At the Avon refinery, the operations supervisor, business team leader, operations shift supervisor, and operations superintendent were four distinct job titles/positions. The operations supervisor worked days and, in particular, was responsible for prioritizing and coordinating maintenance work. He or she reported to the business team leader, who managed an area of the refinery as a business unit, solved day-to-day problems, and implemented long-term projects. The operations shift supervisor (hereinafter referred to as shift supervisor) worked rotating shifts and was the direct supervisor for all operators on his or her crew. The shift supervisor provided both work direction and personnel oversight. Shift supervision and the business team were in separate organizations at the Avon refinery and reported to different operations superintendents.

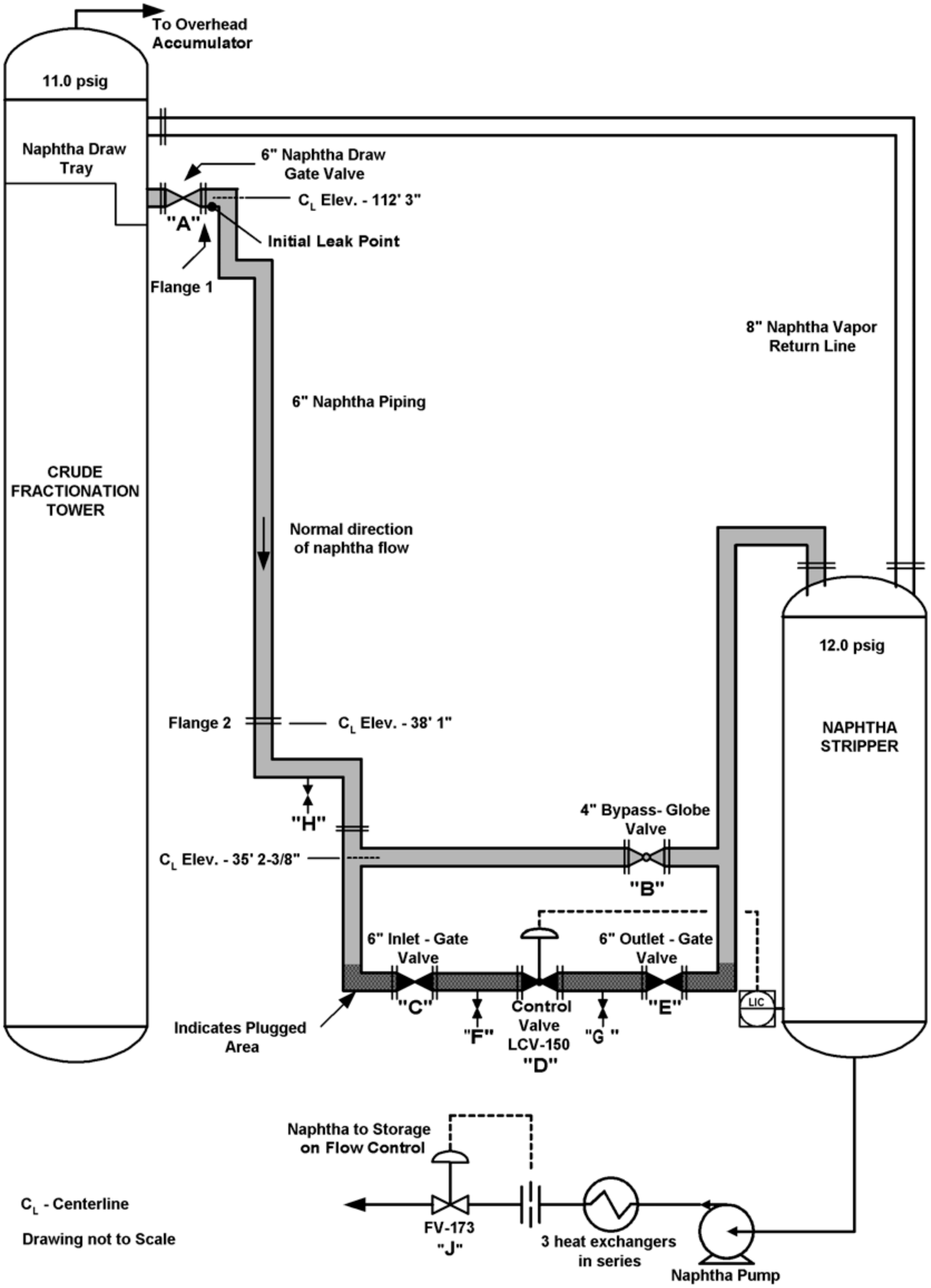

Figure 2. Fractionator and naphtha draw, simplified diagram at time of initial leak.

this job, of which 11 met Tosco's requirements for a special hazard permit (e.g., for inspection radiography, asbestos removal, and lead abatement).

Once the insulation was stripped from the piping, the leak was determined to have originated from a 0.16-inch-long pinhole perforation on the inner radius of an elbow directly downstream of the block valve off the fractionator (valve A), at an elevation of 112 feet. Further inspection using ultrasound and X-ray techniques revealed that much of the piping was severely corroded and thin. Technical staff recommended that the entire line be replaced from valve A to the naphtha stripper.

2.1.3 Recurrence of Leak

On February 13 and 17, operators observed that the leak reoccurred at the original site and that the naphtha piping was warm to the touch. On both occasions, Tosco personnel retightened the piping isolation valves (A and B), and the leak appeared to subside.

On seven occasions from February 10-14, the liquid in the naphtha stripper rose to a high level and was lowered each time by operators opening the naphtha to storage flow control valve (valve J). On the last occasion, they left the valve open to the storage tank to prevent buildup in the stripper; the valve remained open until the day of the fire.

On February 22, while preparing the fractionator area for hot work (i.e., cutting a metal deck to facilitate removal of the piping), the No. 1 operator[7] discovered the naphtha piping again dripping from the original leak point. The piping was hot to the touch. The shift supervisor observed the leak, and a small plug was placed in the hole. After the hot work was finished, the maintenance supervisor directed that the plug be removed.

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[7] Two or three operators were generally assigned to run the 50 Unit. They worked 12-hour rotating shifts. The No. 1 operator functioned as the lead worker and had the primary responsibility for running the unit safely and according to specifications.

2.1.4 Efforts to Drain and Replace Piping

On February 16 and 17, a No.1 operator attempted to drain the naphtha piping under repair using the drain lines (valves F and G) located on either side of the naphtha stripper level control valve (valve D). The attempt failed; the drain lines appeared to be plugged.

Operators advised the operations supervisor on February 17 that it was not feasible to replace the entire naphtha line from the fractionator to the stripper while the unit was still operating, as recommended by the inspection group. They pointed out that the section of line downstream of block valve E to the stripper could not be isolated because there was no block valve on the naphtha vapor return line.

With input from Tosco inspectors, the operations supervisor determined that the downstream piping did not require immediate replacement. The supervisor considered removal of the line from the fractionator to the control valve (valve D) to be a safe option because of the available isolation valves and drain lines.

On February 18, pipefitters again attempted to clear the drain lines (valves F and G) at the naphtha stripper level control valve by using a reaming device. However, the device broke due to the hardness of the material in the line.

On February 19, the maintenance supervisor directed an operator to issue a permit for removal of the spool piece[8] (from valve D to E) just downstream of the naphtha stripper level control valve. The supervisor was present at the job site during removal of the spool piece. The pipe was plugged solid with a dark, tar-like substance, which also contained large chunks of hard material (Figure 3). A blind flange equipped with a drain valve (valve I; Figure 4) was installed on the downstream side of the control valve, and a solid blind flange[9] was attached on the upstream side of the block valve (valve E).

Figure 3. Closeup of material blockage of block valve (C), upstream of LCV-150.

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[8] A "spool piece" is a short piece of pipe flanged on both ends to provide for ease of removal or modification.

[9] This flange is a solid plate piping component used for closing an open end of pipe.

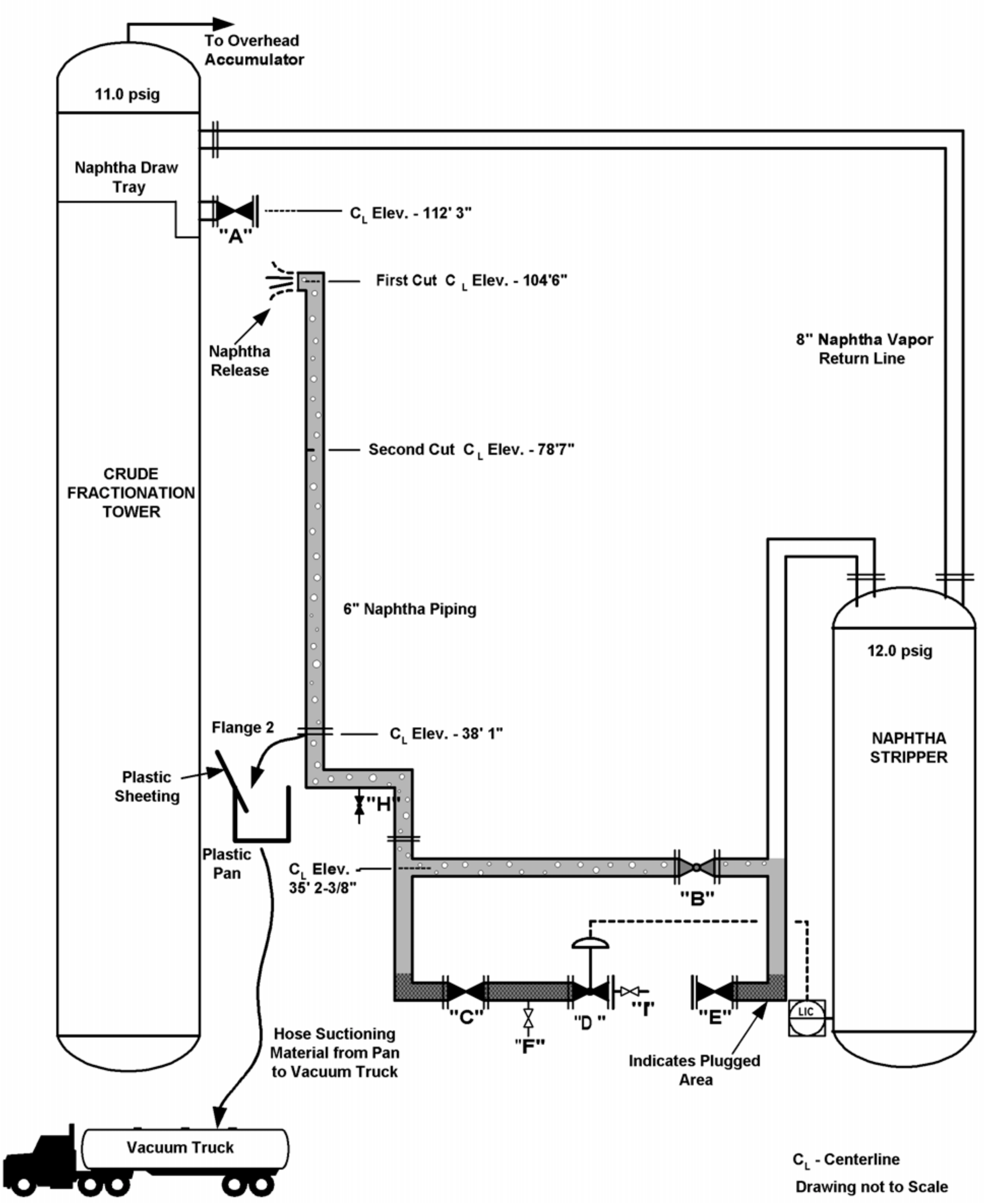

Figure 4. Fractionator and naphtha draw, simplified diagram, draining at lower flange at time of release.

Figure 5. Closeup of stem of block valve (C), upstream of LCV-150, with the valve wheel fully tightened.
The protruding stem shows the valve to be jammed partway open, indicating possible material blockage in the line.

The maintenance supervisor and the workers decided not to remove the spool piece upstream of the control valve (from valve C to D). The supervisor determined that valve C was jammed partway open, and isolation was in doubt (Figure 5). The operator logbook stated that draining would be attempted on Monday, February 22.

However, workers did not attempt to drain the naphtha piping on February 22. The hot work permit for cutting the deck–signed by the shift supervisor, the No. 1 operator, and a maintenance worker–stated that the piping was not drained, locked, or tagged.

The maintenance supervisor and the maintenance lead planner arranged for a vacuum truck to arrive at the job site on February 23 to recover the naphtha.

2.2 The Incident

2.2.1 Job Preparation

On February 23, supervisors, operators, and maintenance workers were aware that the piping contained liquid naphtha. Both the permit readiness sheet and the work permit identified that draining was needed. The No. 1 operator and the maintenance workers inspected the job site and reviewed equipment conditions, and the permit was signed.

In preparation for draining the line, the vacuum truck was placed into position approximately 20 feet from the base of the fractionator. A metal half-barrel was placed under the flange, with the attached drain valve (valve I; Figure 4) downstream of the naphtha stripper level control valve (valve D). A hose was extended from the truck and placed in the barrel. An operator incrementally opened valve D from the control room to assist with draining the line from valve I. Under the direction of their supervisor, the maintenance workers then attempted to open a flange upstream of the control valve. Both efforts to drain the line were unsuccessful.

The maintenance supervisor told the workers present that a section of piping should be cut and removed with the crane. He tapped on the line and stated that he believed the naphtha level was below the proposed cut location. He stated to the operator that listening for differences in the sound at each tap point would identify the liquid level. The operator disagreed and responded that the naphtha should be removed before cutting the pipe.[10]

2.2.2 First Cut and Second Cut

The maintenance supervisor directed workers to unbolt the piping from flange 1, downstream of valve A, and cut a short section of line with a pneumatic saw.[11] The first cut into the line was 8 feet below

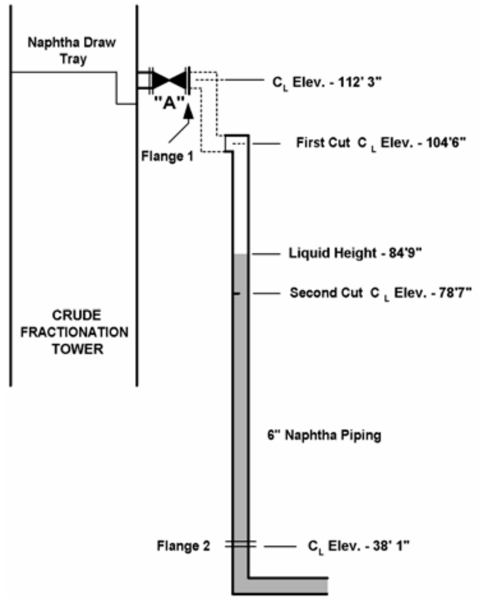

Figure 6. Fractionator and naphtha draw, simplified diagram, first cut and second cut.

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[10] Witnesses in the control room in the late morning stated that the No. 1 operator discussed with them his argument with the maintenance supervisor prior to the fire.

[11] The maintenance supervisor, however, denied that he was present or directed the first cut into the naphtha piping. He stated that he left the unit at 9:00 am. Other witnesses and the timeline of events contradict this testimony. For example, the verbal permit log shows the maintenance supervisor signing into the unit at 8:40 am and departing at 9:50 am. The fact that he directed the work is consistent with his actions both before and after the first cut. The maintenance supervisor acknowledged that he directed the removal of the spool piece on February 19, and the second cut into the line and the opening of the flanges after lunch on February 23–before the piping had been drained or the isolation verified, contrary to Tosco procedures.

valve A. A blind flange was bolted to valve A. The remaining piping was open at the point of the cut and faced the fractionator (Figure 6).

For the second cut, the maintenance supervisor directed workers to start 26 feet below the location of the first cut (Figure 6). When the saw pierced the inside diameter of the pipe wall, a small amount of liquid began to leak from the line. The worker operating the saw ceased cutting and was sent to obtain a pipe clamp to seal the leak.

2.2.3 Naphtha Release

The maintenance supervisor decided to again attempt to drain the line by opening flange 2, located upstream of the naphtha stripper level control valve (valve D) and within 3 feet of the fractionator (Figure 4). Workers loosened the bolts on flange 2, which allowed liquid to flow. Plastic sheeting was hung to deflect the draining liquid away from the hot fractionator and into an open plastic pan, from which it was suctioned to the vacuum truck.

The personnel conducting the work did not take into account that the naphtha piping was pressurized from the running process unit due to a severe leak through a badly corroded valve (valve B). In the "U"-shaped naphtha piping configuration, the head pressure of the vertical column of liquid functioned as a seal and prevented the process pressure from being released to atmosphere out the open end of the cut pipe.

Once the workers drained a sufficient volume of naphtha from the flange on the vertical run of the piping (flange 2), the pressure from the running process unit leaking through the corroded valve surpassed the reduced head pressure in the line. This resulted in a sudden release of liquid from the open piping at approximately 12:18 pm (Figure 4). The naphtha contacted the hot fractionator and ignited, quickly engulfing the tower structure and personnel.

2.3 Autoignition

The autoignition temperature of a material is defined as the temperature at which its fuel/air mixture will ignite from its own heat source or contact with a hot surface, without spark or flame. Tosco's Material Safety Data Sheets (MSDS) for naphtha listed the autoignition temperature as 450 degrees Fahrenheit (°F). However, the lower half of a crude oil fractionator operates at temperatures of 500 to 650°F, and the noninsulated manways protruding from the Avon refinery fractionator had surface temperatures just slightly below this range.

2.4 Emergency Response

Operators heard the naphtha ignite, used fire monitors to direct a stream of water onto the fire, and began an emergency shutdown of the unit. Within minutes, the Tosco emergency response team was on scene and began firefighting efforts. The Contra Costa Fire and Consolidated Fire Departments responded and were positioned to provide support if requested. The fire burned for about 20 minutes.

Rescue efforts were delayed because of the size of the fire, the risk of re-ignition, and the location of most of the victims on the tower. One worker was pronounced dead at the scene, and the other three victims died at the hospital. The fifth worker jumped away from the flames at an elevated location and sustained serious injuries.

3.0 Analysis of Incident

The conduct of maintenance work in an oil refinery often involves flammable and toxic hazards, which must be carefully controlled to avoid injury to people and the environment (Lees, 1996; p. 21/2). In investigating the Avon refinery incident, CSB found problems with job planning, hazard identification and evaluation, unit shutdown decision making, management oversight, permitting and line breaking, corrosion control and mechanical integrity, and management of change (MOC). CSB used several investigative techniques to analyze the incident, including establishing a timeline (Appendix A) and developing a logic tree diagram (Appendix B).

3.1 Hazardous Nonroutine Maintenance

In process plants, hazardous nonroutine maintenance includes such activities as hot work,[12] hot tap,[13] and work on live flare headers as well as line breaking when isolation and drainage cannot be ensured. The nonmandatory appendix in the Occupational Safety and Health Administration's (OSHA) Process Safety Management (PSM) standard[14] stresses the importance of employers identifying the hazards of nonroutine maintenance in process areas and communicating such hazards to those doing the work.

The 1989 Phillips Houston Chemical Complex fire and explosion, which killed 23 workers, expedited issuance of the PSM standard. Like the 1999 Tosco incident, it involved improper isolation of piping and the failure of a valve during the conduct of hazardous nonroutine maintenance work in a running process unit (OSHA, 1990; pp. iv, ix, 72).

Because nonroutine maintenance is unscheduled, it may present special hazards. One such hazard introduced with breakdown maintenance, such as the job at Tosco, involves limitations on job planning (CCPS, 1995b; p. 212).

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[12] Hot work is "an operation that can produce a spark or flame or other source of ignition having sufficient energy to cause ignition, where the potential for flammable vapors, gases, or dust exists" (API, 1995b; pp. 2-3).

[13] Hot tapping is "the technique of attaching a mechanical or welded branch fitting to piping or equipment in service, and creating an opening . . . by drilling or cutting a portion of the piping or equipment within the attached fitting" (API, 1995a; p. 1).

[14] Appendix C of 29 CFR 1910.119, Process Safety Management of Highly Hazardous Chemicals.

3.2 Job Planning

In the Avon refinery incident, preparatory maintenance activities such as stripping insulation and inspecting the piping began immediately after the leak appeared to subside. Job planning at the refinery typically involved a site visit and discussions among the maintenance lead planner, maintenance supervisor, and operations supervisor to identify potential problems in advance. However, this planning activity did not occur for the naphtha repair work.

Just an hour after the leak was discovered, a permit was issued to strip insulation from the naphtha piping. The job was initiated without the line being locked or tagged out, depressured, or isolated, as required by Tosco procedures. If a line could not be isolated, the procedures stated that:

> Production, H&S, Inspection and Maintenance representatives must meet and agree on a safe procedure to remove the insulation. If insulation cannot be safely removed while the unit is online, the line or unit must be shut down.[15]

Although inspection, maintenance, and two operations superintendents were present, no meeting was held to discuss control of hazards. Not following insulation removal procedures did not directly cause the fire, but it was indicative of Tosco's practice of not consistently adhering to established maintenance procedures.

Most of the preparatory maintenance work conducted in the 13 days prior to the incident was not listed in the job planning documentation, including the three permitted jobs where workers attempted to drain the piping. There was no mention that the naphtha, as a benzene-containing stream, was a serious health hazard that required specific precautionary measures; nor was it identified that a crane, vacuum truck, and pneumatic saw were to be used in the piping removal.

No job-specific instructions were prepared for the naphtha piping repair work. The job planning documentation lacked necessary information, such as the MSDS for naphtha, a blind list,[16] or the piping and instrumentation diagram showing where blinds were to be inserted. Good practice guidelines for maintenance job planning

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[15] Tosco Avon Safety Procedure S-36-1, Removing Insulation From Leaking Hydrocarbon Lines, November 20, 1995.

[16] A blind list is a document that specifies the location for blinds to be installed to secure isolation of piping and equipment.

recommend outlining the steps necessary to accomplish the work and identifying the potential hazards of each step (CCPS, 1995b, pp. 249-250; Lees, 1996, p. 21/4).[17]

Adequate planning is also essential for effective isolation of piping and equipment (HSE, 1997; pp. 4, 6, 13).[18] Good practice guidelines emphasize that hazards are most effectively recognized and evaluated in the calm atmosphere of the job planning process rather than during the often stressful environment of job execution (HSE, 1985, p. 11; CCPS, 1995c, p. 17).[19] For example, for hot work–one type of hazardous nonroutine maintenance–API states that the potential hazards should be carefully analyzed as part of pre-job safety planning (API, 1995b; pp. 2-3). Prior to conducting hot tapping, API recommends preparing a written plan that addresses potential hazards and performing the procedure only after careful consideration of alternatives (API, 1995a; pp. 1, 5).

Good practice guidelines emphasize that hazards are most effectively recognized and evaluated in the calm atmosphere of the job planning process rather than during the often stressful environment of job execution.

During planning, Tosco management did not effectively identify the serious hazards present in conducting the piping repair in an operating process unit. Despite accumulating evidence of the inability to drain and isolate the piping during the week leading up to the fire, Avon management scheduled the pipe removal for February 23 with the unit in operation and without a plan to control hazards.

Despite accumulating evidence of the inability to drain and isolate the piping during the week leading up to the fire, Avon management scheduled the pipe removal for February 23 with the unit in operation and without a plan to control hazards.

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[17] Although this CCPS citation references unit shutdown, the practice is even more appropriate for formal consideration during the safe execution of hazardous nonroutine maintenance in an operating unit.

[18] These good practice guidelines were produced in the United Kingdom on a consensus basis by representatives of industry, government, and labor.

[19] In discussing the management dilemma of production versus process safety, CCPS guidelines state: "The continuity of operations can best be addressed at the planning stage."

3.3 Hazard Identification and Evaluation

3.3.1 Job-Specific Hazards

Significant hazards existed early on in the 13-day naphtha piping repair process:

- The job involved the removal of 100 feet of 6-inch pipe containing naphtha, a highly flammable liquid.[20]
- Approximately 80 feet of the piping ran vertically near the side of the fractionator, whose surface temperature in the lower half of the tower exceeded the autoignition temperature of the naphtha stream to be drained.
- The stem of block valve C, upstream of naphtha stripper level control valve D, protruded approximately 12 threads from the valve wheel when fully tightened, indicating that the valve was partially open and possibly plugged. (Unless otherwise noted, all valve and flange locations referenced in Section 3.0 are shown in Figure 2.)
- The lack of a high point vent downstream of valve A would have made it difficult to purge the naphtha piping. [21]

Tosco classified the naphtha piping repair as low risk, routine maintenance. Management did not recognize or evaluate the inability to isolate, inability to drain, or other hazards in light of conducting the work in an operating process unit.

3.3.1.1 Inability to Isolate

On three occasions prior to the fire, the naphtha piping resumed leaking at the original location and the piping felt warm to the touch, indicating that one or more isolation block valves were leaking. In each instance, the valves were further tightened to try to stop the leak.

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[20] Tosco's MSDS for the 50 Unit naphtha stated that the National Fire Protection Association (NFPA) flammability hazard rating for the liquid was 4 (on a 0 to 4 scale, with 4 being the most flammable). However, for the 15 work permits authorized for this repair, the NFPA rating either was not provided or was understated as a 2 or 3.

[21] Purging the piping is important not only to remove residual material, but also to reveal possible plugging or solid material in the line, which can trap pressurized or residual liquids and gases (HSE, 1989, pp. 13-14; Kletz, 1989, p. 13).

On February 13, a shift supervisor helped tighten the valves after the leak reoccurred. On February 17, a maintenance supervisor observed the leak reoccur and assisted operators in tightening the isolation valves. That same day, two operators told the operations supervisor and a maintenance supervisor that more than one valve isolating the naphtha piping was potentially leaking. On the morning of February 23, the operations process engineer stated that he suspected that an isolation valve was leaking.

On seven occasions from February 10-14, the naphtha stripper vessel–which was located downstream of the naphtha piping–filled and operators lowered the level. On February 13, a shift supervisor log recorded that the stripper level had been lowered. This log was typically read by other supervisors and was available electronically to other management personnel. The shift supervisor stated that he suspected a valve might have been leaking. Leakage through the isolation valves was the most likely explanation for recurrence of the high level in the naphtha stripper. [22]

3.3.1.2 Inability to Drain

Draining equipment to remove hazardous material and verifying isolation of the line are essential safety requirements prior to maintenance.

Draining equipment to remove hazardous material and verifying isolation of the line are essential safety requirements prior to maintenance (CCPS, 1995a, p. 310; HSE, 1997, p. 47).[23] From the discovery of the leak to the fire, there were seven failed attempts to drain the naphtha from the piping. Tosco supervisors and workers were aware of the following draining problems:

- On February 16, a No. 1 operator informed the business team leader that the naphtha drain lines were plugged. On February 17, after another unsuccessful draining attempt, two operators discussed plugging in the line with the operations supervisor and

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[22] The naphtha stripper level filling several times in 2-hour intervals, combined with recurrence of the leak, established that the isolation valves were leaking. On February 14, the naphtha flow control valve (valve J) downstream of the stripper was left open, allowing the naphtha to flow out. The stripper remained empty until the day of the fire.

[23] As stated in HSE's *The Safe Isolation of Plants and Equipment:* "Bleeds and vents allow the safe depressurization of parts of the plant when it has been isolated and also enable the integrity of isolations to be checked."

the maintenance supervisor. The operators proposed shutting down the unit to repair the piping. The operator logbook stated that the drain valves were plugged.

- On February 18, the supervisors scheduled maintenance workers to drill out the drain lines. A permit readiness sheet was sent electronically to the operator and the shift supervisor communicating that the drain valves were to be cleared with a reaming device. Permit readiness sheets were also available to management in an electronic bulletin board. After several attempts, maintenance workers informed their supervisor that the material in the piping broke the reaming tool. The operator logbook noted that the attempt to drill out the drain lines was unsuccessful.
- Workers accompanied by the maintenance supervisor removed a small section of piping downstream of the naphtha stripper level control valve (valve D) on February 19. The piping and the drain lines were extensively plugged. Block valve C, upstream of control valve D, was jammed partially open. Both permits executed on February 18 and 19 to drain the piping were checked "job not finished" in the closeout section.
- On February 22, the operations supervisor issued a permit readiness sheet, with input from the maintenance supervisor, stating that draining was part of the work to be performed the following day. A vacuum truck was to be used to collect the naphtha.
- An operations process engineer who visited the unit the morning of the fire was aware that naphtha was still in the piping and was told by operators of the unsuccessful attempts to drain the piping. At the direction of the maintenance supervisor, draining was attempted three times on the morning of February 23.

3.3.1.3 Other Hazards

Another hazard not identified was that the naphtha contained benzene.[24] Because benzene is a carcinogen, Tosco procedures required that equipment be drained to a closed system, away from employees.[25] Maintenance work in the presence of benzene required the use of a special hazard permit with authorization by an operations supervisor. However, Tosco management did not recognize or permit the naphtha piping repair work as a benzene hazard, and these controls were not implemented. Not following these procedures did not directly cause the fire, but demonstrated Tosco's inconsistent adherence to its procedures.

The pipe removal job involved coordinating contractors and workers from different departments, and using a crane in an operating process unit. Furthermore, it required positioning workers where they were potentially subject to the hazard of a sudden release or splashing of flammable liquid. Some workers were located as high as 112 feet above ground. Opening elevated lines is particularly hazardous because of the danger of flammable liquid splashing on personnel or sources of ignition (Kletz, 1989, pp. 14-15; see also CCPS, 1995a, p. 310).

Despite these serious hazards–known to supervisors and workers during the week prior to the incident–the low risk classification of the job was not reevaluated, nor did management formulate a plan to control hazards.

3.3.2 Good Practice Guidelines for Maintenance Work

A hazard evaluation is a formal analytical tool used to identify and examine potential hazards connected with a process or activity (CCPS, 1992; p. 7). The evaluation assists management in process plants in

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[24] Tosco Avon MSDS for 50 Unit Naphtha, MSDS 1001, CSB 9914-E3-023, p. 2. Tosco Avon Safety Order S-29, Benzene, July 1998; Attachment 2.

[25] Tosco Avon Safety Order S-29, Benzene, July 1998; pp. 3, 6-7.

controlling hazards and preventing incidents. The Center for Chemical Process Safety (CCPS) describes evaluation techniques for identifying hazards in maintenance activity in process plants (CCPS, 1992; pp. 11, 428-430). The guidelines suggest a number of questions to be used in performing a hazard evaluation of maintenance work.[26]

In its good practice guide for hazard evaluation, the Institution of Chemical Engineers of the United Kingdom states:

> It is advisable to cover aspects of maintenance operations (with a HAZOP study), including isolation, preparation and removal for maintenance since these often create hazards as well as operability problems (ICE, 2000; p. 8).[27]

A number of factors may necessitate a hazard review of maintenance activity, including:

- Hazardous activities, such as hot work or hot tap and repair work on a live flare line (API, 1995b; pp. 2-3).
- Circumstances where existing procedures cannot be followed or where there are no applicable procedures (HSE, 1997; pp. 17-18).
- Situations where safety preconditions cannot be met, such as controlling ignition sources where flammables may be present.

Good practice guidelines (HSE, 1997, p. 18; see also CCPS, 1992, pp. 428-430) recommend that a comprehensive hazard evaluation include assessment of:

- Specific hazards introduced by performance of the maintenance work.
- Potential problems in achieving adequate isolation, such as depressuring, draining, and purging.
- Additional precautions, such as more frequent monitoring of the isolation, improved supervision, or contingency plans.
- The feasibility of safely conducting work while the process unit is in operation or postponing the job.

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[26] CCPS guidance recommends that hazard evaluation questions include: What hazards are introduced by the maintenance activity? Is it necessary to completely shut down the process to safely conduct the repair?

[27] HAZOP (hazard and operability) is a well-recognized hazard evaluation technique.

3.3.3 British Petroleum Grangemouth Incident

An incident that occurred in 1987 at British Petroleum's Grangemouth refinery in Scotland was similar to the 1999 Tosco fire.[28] The job that led to the Grangemouth incident involved the attempted isolation of a section of a live flare line to remove a faulty valve. Four workers were killed after opening piping thought to be isolated and depressured. Although the isolation valves were placed in the closed position, plugging and valve leakage prevented complete isolation of the piping. The investigation report of the Health and Safety Executive of the United Kingdom made the following recommendations for senior management (HSE, 1989; pp. 13-14):

- Conduct a detailed hazard analysis during job planning.
- Before delegating work, develop detailed job instructions specific to the particular isolation to ensure the effective draining of flammable liquids.
- Maintain rigorous control over possible ignition sources in the vicinity of maintenance work.

3.4 Unit Shutdown Decision Making

Because of insufficient job planning and hazard evaluation, Tosco Avon refinery management did not recognize that safe conduct of the naphtha piping repair required shutting down the process unit. Once supervisors and workers knew that the line could not be drained or isolated, the unit needed to be shut down to safely conduct the repair. CSB recognizes that the shutdown and startup of an oil refinery process unit can introduce its own risks; however, the safe conduct of maintenance work requires a unit shutdown when serious hazards cannot otherwise be controlled or when the work cannot be deferred.

Because of insufficient job planning and hazard evaluation, Tosco Avon refinery management did not recognize that safe conduct of the naphtha piping repair required shutting down the process unit.

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[28] See also "Lessons Learned From an On-Plot Refinery Tank Explosion," CCPS, 2000; p. 3. A lesson learned from the incident: "Pre-job hazard assessment should be conducted. Removing the strainer was a nonroutine task. The job planning and control did not include a discussion of the hazards by the personnel doing the job."

In spite of evidence that the line contained naphtha and was severely plugged, operations supervisors scheduled the piping removal. Multiple sources of ignition were as close as 3 feet from the repair work. Hot equipment surfaces, the most likely source of ignition, could be eliminated as a hazard only if the equipment was cooled, which required shutting down the unit. The work could not be deferred because the piping required immediate replacement. In an effective maintenance work evaluation process, CCPS recommends that management carefully consider whether it is "necessary to shut down the process completely to safely repair a piece of equipment" (CCPS, 1992; p. 429).

3.5 Management Oversight

3.5.1 Accountability for Hazardous Work

Despite significant hazards, Tosco management planned and executed the naphtha piping repair work as low risk maintenance. Under Tosco procedures, the unit operator was solely responsible for authorizing this work. Operations supervisors were minimally involved in planning or overseeing the line repair. No senior management or specialist personnel participated in assessing hazards. Although inspection personnel were included in decision making concerning the scope of the repair, their participation was limited to reviewing inspection data and determining what sections of the piping required immediate replacement.

A management system of accountability should include methods for establishing responsibility, evaluating performance, establishing feedback systems, and auditing.

Management oversight and accountability are essential elements of an effective PSM program. A management system of accountability should include methods for establishing responsibility, evaluating performance, establishing feedback systems, and auditing (CCPS, 1995c; p. 15).

At CSB's request, API and NPRA prepared a document on oil refining industry practices for authorizing repair and maintenance work. It states that for situations involving higher risk, such as hot work or the inability to isolate a leaking line, a higher degree of management scrutiny and approval may be needed: [29]

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[29] See also CCPS, 1995b; p. 229.

> Depending on the degree of risk some jobs may require, at a minimum, the approval of both a senior level safety person and the operations manager to deviate from routine or defined work practices. Higher risk jobs may require a risk management team including both labor and management level persons and safety, operations, maintenance, engineering, metallurgy and other disciplines depending on the nature of the work request (API/NPRA, 2000).

If a multidisciplinary team and senior management had participated in evaluating hazards and determining whether to shut down the process unit to safely conduct the repair, it is likely that the job would not have been allowed to proceed and the incident would not have occurred.

3.5.2 Supervision of Job Execution

The conduct of hazardous nonroutine maintenance requires close supervision, including frequent monitoring and unscheduled checks (CCPS, 1995b, p. 212; Townsend, 1998, p. 49). At the Avon refinery, operations supervisors stated that they oversaw activities in the process units when requested by the operators or as needed. On the morning of the incident, operations supervisors did not oversee the naphtha piping removal. The operations supervisor responsible for coordinating maintenance was not at work on February 23; the person responsible for filling in during such absences did not visit the unit prior to the fire.

The shift supervisor phoned the No. 1 operator prior to initiation of the piping repair work, asking if there were any problems in the unit. The operator responded that there were none. The shift supervisor visited the unit the morning of the incident, but did not observe the piping repair activities, review the permit, or inquire about the status of the draining attempts that had been ongoing for over a week.[30] Also, no health and safety personnel visited the job site before the incident occurred. Despite the presence of a crane, a vacuum truck, and

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[30] The job description of the shift supervisor states the he or she is "accountable for everything that takes place with their crew," including ensuring "that all equipment is prepared properly and timely, that permits are completed and signed as appropriate per scheduled maintenance plan."

numerous contractors, the maintenance supervisor was the only management representative present during the conduct of the repair work on February 23.

A number of other deviations from Tosco procedures and good practice guidelines occurred during the naphtha piping repair activities. Although the following deviations were not directly causal to the incident, they demonstrated a pattern of serious management oversight deficiencies regarding maintenance activities at the Avon refinery:

- Naphtha was not recognized as a benzene stream and a health hazard. None of the piping repair work activities adhered to Tosco's benzene procedure, which required a special hazard permit and safety precautions, such as engineering controls, a benzene regulated area, personal protective equipment (PPE), and benzene exposure monitoring. [31]
- The use of a vacuum truck on February 23 was not included in the work permit, nor was a mobile entry permit issued, as required by Tosco procedures. [32]
- The use of a pneumatic saw in the piping removal was not included in the work permit, another requirement under Tosco procedures.[33]
- Several special hazard work permits authorized for the naphtha piping repair were not signed by the shift supervisor, as required by Tosco procedures.

Tosco procedures delegated to the operator the primary responsibility for identifying and controlling the hazards present in hazardous nonroutine repair. Process safety expert Frank Lees advises:

> It is desirable to include a caution to the effect that . . . although work may be delegated, responsibility remains with him (supervision); an indication of the levels of hazard so that high hazard situations are highlighted and those involved are prompted to consider whether there are other parties who should be consulted (Lees, 1996; p. 21/16).

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[31] Tosco Avon Safety Order S-29, Benzene, July 1998.

[32] Tosco Avon Procedure TRFE003, Procedure for 100-Barrel Vacuum Truck, September 1995.

[33] Tosco Avon Procedure PFFE005, Procedure for Portable Power Pneumatic Hacksaw, December 1995.

Inadequate supervision was one of the issues the U.S. Environmental Protection Agency (EPA) investigated in its analysis of a fatal incident in the hydrocracker unit at the Avon refinery in 1997. EPA reported that inadequate supervision was a causal factor in the failure of a reactor effluent pipe and one fatality (USEPA, 1998; p. 65). The report stated that supervisor oversight of operations was deficient and contributed to the lack of adherence to emergency procedures. EPA concluded that there was no supervision at the unit during the hazardous abnormal situation, even though there had been a succession of operating problems prior to the temperature excursion that led to the pipe failure and fire.

3.5.3 Stop Work Authority

Tosco workers involved in the piping repair stated that they felt pressure to promptly execute the job because the unit was the only crude unit operating at that time.[34] Pressure to complete the job was also created by the presence of the vacuum truck, a crane, and contract workers.

Tosco management stated that workers had the authority to stop unsafe work activity and should have stopped the line replacement job. However, stop work authority–though a desirable safety policy if properly encouraged–is a less effective measure for incident prevention than good job preplanning for the following reasons (HSE, 1985, p. 11; CCPS, 1995c, p. 17):

- It is exercised during the execution of work, when pressures to get the job done are generally greater.[35]
- It relies on the assertiveness of individual workers. To attempt to stop a job, a worker may need to assert a position that runs contrary to direct instructions from a supervisor.
- Once the job has begun, the idling of contractors and equipment can result in significant financial cost to the facility, which can add to the pressure to get the job done without delay.

Stop work authority–though a desirable safety policy if properly encouraged–is a less effective measure for incident prevention than good job preplanning.

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[34] The No.3 unit was shut down in December 1998 and was being decommissioned.

[35] In discussing the management dilemma of production versus process safety, CCPS guidelines state: "The continuity of operations can best be addressed at the planning stage." (CCPS, 1995c; p. 17)

3.5.4 Auditing

The Avon refinery's safety auditing program consisted of undocumented observations (referred to as "layered safety surveys"). [36] These observations focused on worker behavior rather than measuring the effectiveness of procedures; they did not record findings, make recommendations, or track corrective actions.

In 1995, Tosco conducted a documented audit of its PSM program, as required every 3 years by Cal/OSHA. Tosco did not conduct a PSM compliance audit in 1998. Furthermore, neither Tosco Corporation nor Avon refinery management conducted documented audits of the facility's line breaking, lock-out/tag-out, or blinding procedures and practices in the 3 years prior to the incident.

Tosco's auditing program did not record or remedy the pattern of serious deviations from the safe performance of maintenance work and proper review of operational changes in process units. These deviations included:

- Opening of piping containing flammable liquids prior to draining.
- Transfer of flammable liquids to open containers proximate to sources of ignition.
- Inconsistent use of blind lists.
- Lack of supervisory oversight of hazardous work activities.
- Inconsistent use of MOC reviews for process changes.

Industry good practice guidelines recommend that an audit program consist of documenting findings, formulating corrective action to improve performance, and instituting followup controls.

Safety audits are an essential feedback mechanism for the effective functioning of a facility's safety management system. Industry good practice guidelines recommend that an audit program consist of documenting findings, formulating corrective action to improve performance, and instituting followup controls (CCPS, 1995c; pp. 313, 316).

Effective audits would have likely detected the inconsistent adherence to procedures at the Avon refinery and could have corrected these problems prior to the incident.

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[36] Tosco asserted that some other documented audits were conducted at the Avon refinery, but did not provide CSB with evidence of such audits. Interview evidence indicates that no audits were conducted other than the layered safety surveys and the 1995 compliance audit.

3.6 Permit System and Line Breaking Procedure

3.6.1 Permit and Procedure Deficiencies

Deficiencies in two key elements of the maintenance work system–permitting and line breaking–contributed to causing the refinery fire.

The Avon refinery used written procedures, including a permitting system, to prepare equipment for maintenance work. The safe work procedure, which governed the work permitting system, applied to "all low risk and special hazard work."[37] The opening of pipelines or equipment required permitting. The procedure stated that the operator must ensure that equipment is depressured, drained, flushed, and purged of chemicals as completely as possible.

The authority to approve and issue work permits was generally delegated to operators; however, some types of higher hazard work required the approval of the shift supervisor or a health and safety department specialist. Higher hazard work included jobs that required entry into confined spaces, jobs that involved high energy hot work,[38] and those categorized as special hazard (e.g., opening live flare lines, radiography, and exposure to toxic materials such as lead, asbestos, benzene, and butadiene).

Deficiencies in the permitting system at the Avon refinery were exemplified by the permit issued on the day of the incident, which listed three tasks with different preparation requirements. By listing draining and removal together, the permit allowed both activities to be authorized even though draining was required before removal of the piping.[39]

The following deviations from good practice occurred with regard to line breaking and contributed to causing the incident:

- Hazardous nonroutine maintenance work was executed without a review of the job or permit authorization by an operations supervisor.

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[37] Tosco Avon Procedure S-5, Safety Orders, Departmental Safe Work Permits, October 1998.

[38] Jobs that might result in sparks are defined as low energy hot work. Tasks involving the use of direct flames (such as torch cutting or welding) are defined as high energy hot work.

[39] Tosco procedures did not restrict work authorizations to one job per permit.

- Neither Tosco procedures nor the permit clearly indicated that personnel were to eliminate or effectively control sources of ignition prior to opening equipment.
- No course of action was specified if the required preparatory steps for opening piping, such as draining, could not be accomplished.

3.6.1.1 Inability to Follow Procedures

Good practice guidelines on equipment opening recommend that permits and procedures provide direction as to what course of action to take if existing hazards cannot be controlled or new hazards arise (Lees, 1996; p. 21/22). If the hazards require variation from the normal level of isolation, the work should be stopped and a hazard evaluation conducted by an appropriate level within management (HSE, 1997; p. 17). Tosco's permit system and procedures did not provide direction on what course of action to take if a line could not be drained.

3.6.1.2 Identification of Specific Hazards

In addition, industry good practice guidelines recommend that permits and procedures identify the specific hazards that may be encountered (Lees, 1996; p. 21/22). Neither Tosco procedures nor the permit form addressed the hazards of open containers of flammables or ignition sources from hot equipment surfaces, which were as close as 3 feet from the piping removal work. Workers were directed by the maintenance supervisor to drain the highly flammable liquid into an open plastic pan with multiple sources of ignition nearby. Process safety expert Trevor Kletz notes the often-unrecognized hazards of open containers (Kletz, 2000; p. 4). He emphasizes that open containers of flammable liquids should not be used in process plants because of the many potential ignition sources.

Another potentially hazardous activity was the transfer of naphtha to the vacuum truck, which was parked approximately 20 feet from the fractionator. Tosco procedures did not contain spacing requirements for placement of the truck. Good practice guidelines recommend that vehicles used for transferring flammable liquids not be allowed within at least 100 feet of sources of ignition (API, 1999; p. 9).

The potential hazard of static electricity was another issue not addressed by procedures or the permit system. Just prior to the incident, a plastic pan and sheeting were used to drain naphtha from the flange located near the fractionator. Transferring flammable liquids to a container such as a plastic pan or the use of plastic sheeting–both of which have insulating properties–may generate a static electrical charge. Furthermore, splashing of the liquid may also generate static electricity (NTSB, 1999; p. 2).

3.6.2 Deviations From Good Practice

Failure to drain the line prior to opening was another deviation from good practice. On several occasions during the course of the repair work, equipment had been opened prior to draining. On February 19, a small section of piping was removed before draining in an unsuccessful attempt to unplug the line. On the morning of the incident, the maintenance supervisor directed workers to cut and remove the top 9-foot section of the naphtha piping.[40] Personnel working on the removal job were aware that the piping contained naphtha. Two flanges were opened in an attempt to remove the naphtha, and another flange was opened when the top section of piping was removed. Tosco procedures required draining prior to opening equipment or using a pneumatic saw. [41]

It was a historical practice at the Tosco refinery to sometimes open equipment containing flammable liquids prior to draining. When drain lines were plugged or not available, witnesses described opening flanges in operating process units to release flammable liquids into an open container or onto the ground. Supervisors and workers did not perceive that this departure from Tosco procedures was a serious hazard.

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[40] The pipe was cut using a pneumatic saw.

[41] Tosco Avon Procedure S-5, Safety Orders, Departmental Safe Work Permits, October 19, 1998; and PFFE005, Procedure for Portable Power Pneumatic Hacksaw, December 1995.

Good practice guidelines for process plants recommend that flanges not be opened or lines cut prior to draining flammable liquids (Lees, 1996; p. 21/26). Moreover, draining of flammables should take place through a closed system so as to shield the liquid from sources of ignition (Amoco, 1984; p. 13).[42] In addition, the use of a flange to drain flammable liquids in a running process unit with nearby sources of ignition is an unsafe practice because neither the rate nor the direction of flow can be adequately controlled, and it may be difficult to quickly stop the flow if needed.

3.7 Corrosion Control and Mechanical Integrity

3.7.1 Desalter Performance

A desalter is a crude oil processing vessel that reduces corrosion, plugging, and fouling of piping and equipment by removing inorganic salts, water, suspended solids, and water-soluble trace metals. The accelerated rate of corrosion in the naphtha piping was predominantly caused by a decrease in desalter performance and the entry of excessive amounts of water and corrosives into the fractionator (Hendrix, 2000; p. 1).

The accelerated rate of corrosion in the naphtha piping was predominantly caused by a decrease in desalter performance and the entry of excessive amounts of water and corrosives into the fractionator.

In the year prior to the incident, the desalter was run 40 percent beyond design capacity using heavier crude oils. The API gravity of the crude feed to the unit dropped on average from 27.2° in 1997 to 23.7° in 1998. Heavier oils with a lower API gravity are more difficult to separate from water, which impedes the desalting process.

Two internal incident reports describe desalter upsets that were directly related to crude feed and vessel problems at the Avon refinery. A September 1998 report recommended better dewatering of the crude. A March 1998 report described a serious incident when the gravity of the feed to the unit fell to 18° API. The report stated

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[42] As Amoco reports: "Some equipment drains used during the shut down operation may not have permanent connections to a pump-out or closed drain system. If the material released from these drains can burn and then injure persons and damage equipment, install temporary facilities to drain the material to a closed system or another safe place."

that increased corrosion rates could be expected, specifically in the fractionator overhead and naphtha systems.

Operating logs for the unit noted more than two dozen desalter upsets during 1998. Performance deteriorated severely late in the year when the No. 3 crude unit was shut down. A process engineer described the desalter performance as "hopeful to non-existent." The chemical contractor for the desalter, Nalco/Exxon, also documented concerns about performance in a November 1998 memo, which stated that efforts to run the desalters efficiently had "never been more difficult."[43]

A process engineer described the desalter performance as "hopeful to non-existent."

In a memo written in November 1998, Tosco management identified several potential improvements for immediate study and evaluation. These included operating the desalter vessels in parallel instead of in series, relocating a desalter from the No. 3 unit, and changing the electrolytic technology. Proposed solutions related to ongoing dewatering problems were also identified. Although Tosco management recognized the operational problems with the desalter, they did not adjust their equipment inspections accordingly;[44] nor did they implement corrective actions in a timely way to prevent material from plugging the pipe and to prohibit excessive corrosion in the unit.

3.7.2 Corrosion

Maintenance records and notations in the operator's logbook revealed that as early as May 1998 the naphtha stripper level control valve (valve D) did not allow sufficient flow to maintain a liquid level inside the naphtha stripper. The bypass was run in the partially open position for at least 10 months prior to the incident, and the valve became plugged with solid corrosion deposits. The piping near valve D and the associated drain valves eventually became totally plugged. Long-term use of the partially open bypass valve also made it susceptible to erosion/corrosion.

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[43] Nalco/Exxon Energy Chemicals memorandum to Tosco Corporation, "50 Unit Desalters Status," November 10, 1998.

[44] CSB investigators retained The Hendrix Group to examine corrosion and mechanical integrity issues related to this incident. The Hendrix Group found shortcomings (Appendix C) with the unit inspection program. However, CSB concluded that these problems were not directly causal to the fire.

Following the incident, Cal/OSHA commissioned a metallurgical analysis of the failed piping and components. It was determined that the bypass valve was eroded to such an extent that–when closed–it leaked (Figure 7) at a rate equivalent to a 1.5-inch-diameter hole (FTI Anamet, 1999; p. i).

It was determined that the bypass valve was eroded to such an extent that–when closed–it leaked at a rate equivalent to a 1.5-inch-diameter hole.

Figure 7. Leak test of the naphtha stripper level control bypass valve (B) in the closed position, showing significant water flow.
The inset photo highlights the gap between the seat and disc of the bypass valve in the closed position. This gap was equivalent to a 1.5-inch-diameter hole.

FTI Anamet determined that excessive amounts of ammonium chloride in the naphtha intensified the corrosive activity. Multiple analyses of residue specimens from the line were found to have very high chloride contents. This corrosive salt found its way into the fractionator and naphtha draw piping when the overhead reflux contained excessive water due to a large volume of water in the crude feed. The combination of corrosive salts and water in the naphtha piping led to excessive accelerated oxidation, which produced the original leak as well as the plugging in the piping and erosion/corrosion in the bypass valve. CSB investigators determined that the naphtha line was plugged with iron oxide, ammonium chloride, and sulfur compounds, which were either corrosive materials or products of corrosion.

In recognizing problems with chloride salt accumulation and plugging in the naphtha section of the fractionator tower, Tosco Avon management developed a water washing procedure to flush chlorides from the naphtha section of the tower.[45]

The combination of corrosive salts and water in the naphtha piping led to excessive accelerated oxidation, which produced the original leak as well as the plugging in the piping and erosion/corrosion in the bypass valve.

3.8 Management of Change

Tosco Avon management did not conduct an MOC review of the potential safety effects on the fractionator and associated piping that might result from:

- Operating the desalter beyond its design parameters.
- Increasing water in the crude feed.
- Shutting down the No. 3 unit and resulting effects on the 50 Unit.

API Recommended Practice 750 recommends that refiners review hazards that may be introduced as a result of projects or changes in operating conditions that increase throughput or accommodate different feedstocks (API, 1990; p. 4).

The Avon refinery's MOC program required an MOC review to be performed with a change in feedstocks.[46] Moreover, Tosco's program and API 750 stated that an MOC review should occur prior to changing design conditions. A Nalco/Exxon memo in December 1998 stated that the crude feed to the desalters was further increased to 55 to 80 percent over design specifications.[47] Not conducting an

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[45] Tosco Avon Procedure 16-MS-06, Water Washing the Main Fractionator, September 1998.

[46] Tosco Avon Safety Order S-12, Management of Change Policy, March 1998; p. 8.

[47] Nalco/Exxon Energy Chemicals memorandum to Tosco Corporation, "50 Unit Desalters Report," December 7, 1998.

MOC review of changes in the feedstocks contributed to causing excessive rates of corrosion in the naphtha piping.

API 750 recommends conducting an MOC review for changes in technology that include "bypass connections around equipment that is normally in service."

In addition, management did not conduct an MOC review for the process change of running with the naphtha stripper level control bypass valve partially open for a prolonged period. API 750 recommends conducting an MOC review for changes in technology that include "bypass connections around equipment that is normally in service" (API, 1990; p. 5). Not conducting an MOC review for operation of the bypass valve in the partially open position for months at a time resulted in the buildup of semisolid material in the control valve piping and drain lines, as well as erosion/corrosion of the valve seat and disc.

4.0 Root and Contributing Causes

4.1 Root Causes

1. **Tosco Avon refinery's maintenance management system did not recognize or control serious hazards posed by performing nonroutine repair work while the crude processing unit remained in operation.**

   - Tosco Avon management did not recognize the hazards presented by sources of ignition, valve leakage, line plugging, and inability to drain the naphtha piping. Management did not conduct a hazard evaluation of the piping repair during the job planning stage. This allowed the execution of the job without proper control of hazards.
   - Management did not have a planning and authorization process to ensure that the job received appropriate management and safety personnel review and approval. The involvement of a multidisciplinary team in job planning and execution, along with the participation of higher level management, would have likely ensured that the process unit was shut down to safely make repairs once it was known that the naphtha piping could not be drained or isolated.
   - Tosco did not ensure that supervisory and safety personnel maintained a sufficient presence in the unit during the execution of this job. Tosco's reliance on individual workers to detect and stop unsafe work was an ineffective substitute for management oversight of hazardous work activities.
   - Tosco's procedures and work permit program did not require that sources of ignition be controlled prior to opening equipment that might contain flammables, nor did they specify what actions should be taken when safety requirements such as draining could not be accomplished.

2. **Tosco's safety management oversight system did not detect or correct serious deficiencies in the execution of maintenance and review of process changes at its Avon refinery.**

   Neither the parent Tosco Corporation nor the Avon facility management audited the refinery's line breaking, lockout/tagout, or blinding procedures in the 3 years prior to the incident. Periodic audits would have likely detected and corrected the pattern of serious deviations from safe work practices governing repair work and operational changes in process units. These deviations included practices such as:

- Opening of piping containing flammable liquids prior to draining.
- Transfer of flammable liquids to open containers.
- Inconsistent use of blind lists.
- Lack of supervisory oversight of hazardous work activities.
- Inconsistent use of MOC reviews for process changes.

4.2 Contributing Causes

1. **Tosco Avon refinery management did not conduct an MOC review of operational changes that led to excessive corrosion rates in the naphtha piping.**

   Management did not consider the safety implications of process changes, such as:

   - Running the crude desalter beyond its design parameters.
   - Excessive water in the crude feed.
   - Prolonged operation of the naphtha stripper level control bypass valve in the partially open position.

   These changes led to excessive corrosion rates in the naphtha piping and bypass valve, which prevented isolation and draining of the naphtha pipe.

2. **The crude unit corrosion control program was inadequate.**

   Although Avon refinery management was aware that operational problems would increase corrosion rates in the naphtha line, they did not take timely corrective actions to prevent plugging and excessive corrosion in the piping.

5.0 Recommendations

Tosco Corporation

Conduct periodic safety audits of your oil refinery facilities in light of the findings of this report. (1999-014-I-CA-Rl) At a minimum, ensure that:

- Audits assess the following:
    - Safe conduct of hazardous nonroutine maintenance
    - Management oversight and accountability for safety
    - Management of change program
    - Corrosion control program.
- Audits are documented in a written report that contains findings and recommendations and is shared with the workforce at the facility.
- Audit recommendations are tracked and implemented.

Ultramar Diamond Shamrock Golden Eagle Refinery

1. **Implement a program to ensure the safe conduct of hazardous nonroutine maintenance. (1999-014-I-CA-R2) At a minimum, require that:**

- A written hazard evaluation is performed by a multidisciplinary team and, where feasible, conducted during the job planning process prior to the day of job execution.
- Work authorizations for jobs with higher levels of hazards receive higher levels of management review, approval, and oversight.
- A written decision-making protocol is used to determine when it is necessary to shut down a process unit to safely conduct repairs.
- Management and safety personnel are present at the job site at a frequency sufficient to ensure the safe conduct of work.
- Procedures and permits identify the specific hazards present and specify a course of action to be taken if safety requirements–such as controlling ignition sources, draining flammables, and verifying isolation–are not met.
- The program is periodically audited, generates written findings and recommendations, and implements corrective actions.

2. Ensure that MOC reviews are conducted for changes in operating conditions, such as altering feedstock composition, increasing process unit throughput, or prolonged diversion of process flow through manual bypass valves. (1999-014-I-CA-R3)
3. Ensure that your corrosion management program effectively controls corrosion rates prior to the loss of containment or plugging of process equipment, which may affect safety. (1999-014-I-CA-R4)

American Petroleum Institute (API)

Paper, Allied-Industrial, Chemical & Energy Workers International Union (PACE)

National Petrochemical & Refiners Association (NPRA)

Communicate the findings of this report to your membership. (1999-014-I-CA-R5)

By the

U.S. CHEMICAL SAFETY AND HAZARD INVESTIGATION BOARD

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March 21, 2001

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APPENDIX A: Incident Timeline

1. **February 10, 1999, Wednesday**

   a. 1:20 pm: A leak was detected in the 50 Unit at the first elbow of the naphtha piping leaving the crude fractionator tower (just downstream of valve A; Figure 2).

   b. Emergency responders arrived at the scene of the leak with firefighter personal protective equipment (PPE) and self-contained breathing apparatus (SCBA). Fire hoses and a snorkel truck were set up in case of a fire and used to wash down the fractionator tower and decks.

   c. The following valves were placed in the closed position to isolate the naphtha piping–the block valve on the naphtha draw line near the fractionator (valve A), block valves C and E upstream and downstream of the naphtha stripper level control valve (valve D or LCV-150), and the naphtha stripper level control bypass valve (valve B).[1] The naphtha piping appeared to stop leaking. No clamp was installed on the leaking section of the pipe.

   d. 2:25 pm: Work began to strip insulation from the naphtha piping. The operations superintendent and the superintendent of shift operations were on scene during isolation of the line and at the beginning of the insulation removal work.

   e. An emergency work order was requested to replace the naphtha piping.

   f. The naphtha piping was inspected using ultrasonic and radiographic testing to identify the extent of wall thinning.

   g. 9:40 pm: The liquid in the naphtha stripper vessel rose to a high level. Operations personnel lowered the liquid level by opening the naphtha to storage flow control valve (valve J; Figure 2), downstream of the naphtha stripper.

2. **February 11, Thursday**

   a. As a result of the initial inspection, a decision was made to replace all of the naphtha piping from the fractionator to the naphtha stripper.

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[1] Valves A, B, C, and E (Figure 2) are also referred to as the isolation valves.

   b. Contract workers began erecting scaffolding on the fractionator to provide access to the piping.

3. **February 12, Friday:** The liquid level in the naphtha stripper increased again and was lowered by operations personnel.

4. **February 13, Saturday**

   a. A No. 1 operator observed naphtha "misting" from the hole on the naphtha line at the site of the original leak on February 10. The naphtha piping felt warm to the touch. The No. 1 operator and the shift supervisor tightened the isolation valves with a wrench and an extension in an attempt to stop the leak. The leak appeared to subside.

   b. The operator logbook noted that "the ruptured draw line is full" in reference to the naphtha piping that had been leaking.

   c. The high naphtha stripper level was lowered after retightening of the isolation valves (see 4.a above). The shift supervisor's log (referred to as "area notes"), available electronically, recorded that the naphtha stripper level was lowered. The shift supervisor stated that the block valves isolating the naphtha piping might have been leaking.

5. **February 13 and 14:** During the night shift into the morning of February 14, the operators lowered the level in the naphtha stripper on four different occasions. After the fourth occurrence, the naphtha flow control valve (valve J) was left open so that the naphtha could flow through the pump to storage, thus preventing the stripper from refilling.

6. **February 16, Tuesday:** The No. 1 operator attempted to drain the naphtha piping from drain valves F and G on either side of the naphtha stripper level control valve. A hose was attached to the drain valves running to the ground level. No liquid was removed. The No. 1 operator informed the business team leader that the naphtha drain lines were plugged.

7. **February 16 and 17:** The job scope was reduced after it was determined that portions of naphtha piping could not be isolated to allow replacement of all the piping while the unit was running.

Tosco inspectors reevaluated the thickness data and concluded that the portion of piping between the naphtha stripper level control valve (valve D) and the naphtha stripper did not need immediate replacement.

8. **February 17, Wednesday**

   a. The maintenance supervisor observed a small stream of naphtha intermittently draining from the point of the original leak. The line felt warm to the touch, and the maintenance supervisor assumed that the block valve (valve A) on the naphtha piping near the fractionator was leaking from the fractionator. The operator logbook recorded that isolation valves were again retightened (valves A and B).

   b. The No. 1 operator opened the drain valves (valves F and G) on either side of the naphtha stripper level control valve (valve D). When no flow was observed, the operator used a welding rod[2] to attempt to clear the plugging in the drain lines. Again, no flow was observed. It was recorded in the logbook that the drain lines were plugged and could not be cleared.

   c. The failed attempt to drain the naphtha piping was communicated by two No. 1 operators to the operations supervisor and the maintenance supervisor. The operators presented a plan to shut down the unit if the plugging could not be cleared. The operations supervisor initiated a request for maintenance workers to clear the drain lines (connected to valves F and G).

   d. Maintenance personnel began to sketch and detail the specifications of the naphtha piping for replacement.

9. **February 18, Thursday, noon:** Maintenance workers were in the unit to "unplug 1-inch drain valves (valves F and G) and drain the 6-inch naphtha piping on the fractionation tower." After repeated unsuccessful attempts to drill out the plugged drain lines near the naphtha stripper level control valve (valve

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[2] The use of a wire or rod to unplug a drain line is an unsafe procedure (Amoco, 1984; p. 49).

D), the reaming device broke. The safe work permit was marked as "job not finished."

10. **February 19, Friday**

    a. In the maintenance work schedule report for the following week, the maintenance lead planner requested a crane to remove naphtha piping for Tuesday, February 23.

    b. 12:05 pm: In response to unsuccessful attempts to unplug the drain lines, a safe work permit was issued to remove a short piping spool piece downstream of the naphtha stripper level control valve (between valves D and E). This work was directed and witnessed by the maintenance supervisor, who signed into the unit for 2 hours to oversee the work.

    c. The spool piece (between valves D and E) was removed. The block valves (valves C and E) were not locked out. Block valve C was observed by the maintenance supervisor to be jammed partially open. The spool piece was not drained, nor was isolation of the block valves verified prior to removal. The spool piece was full of semisolid material, which plugged the line. A blind flange with a drain valve (valve I; Figure 4) was installed on the downstream side of the naphtha stripper level control valve (valve D). No attempts were made to drain the line after this activity. The safe work permit was marked "job not finished."

11. **February 22, Monday**

    a. The operations supervisor prepared a permit readiness sheet with input from the maintenance supervisor. The sheet stated, "Bigge, Interstate Scaffold, Tosco and Rust personnel to drain and start removal of naphtha draw piping." This document was available electronically and sent to the shift supervisor.

    b. The No. 1 operator observed the leak reoccur at the original location. The naphtha piping felt warm to the touch. The shift supervisor was brought up to the deck to observe the leak.

c. A hot work permit was issued to cut out a section of the deck on a platform on the fractionator tower, 107.5 feet above grade. To contain the naphtha while the cut was made, a plug was placed in the perforation of the piping where the leak had occurred. The maintenance supervisor directed the plug to be removed upon completion of the hot work.

d. The maintenance supervisor and the maintenance lead planner arranged for a vacuum truck from a contracting company for the next day.

e. An operator prepared a permit during the nightshift to "Erect scaffolding, drain and remove piping (naphtha draw)."

12. February 23, Tuesday

a 7:20 am: A vacuum truck from Waste Management Industrial Services arrived at the unit.

b. 7:40 am: Tosco maintenance employees arrived at the unit to "drain and remove naphtha piping."

c. 8:00 am: A Bigge crane operator and rigger arrived at the unit to assist in removing the piping.

d. 8:00 am: The operations process engineer visited the unit and discussed the naphtha piping replacement. An operator told him that several draining efforts had been unsuccessful and that the reaming device used to clear the drain lines (connected to valves F and G) had broken on February 18. The engineer suspected that the naphtha piping isolation valves were leaking. He was aware that naphtha was in the piping.

e. 8:30 am: A maintenance worker and a No. 1 operator reviewed the job site and signed a safe work permit prior to the start of the job.

f. 8:40 am: The maintenance supervisor entered the unit to supervise the naphtha piping replacement job.

g. 8:50 am: A maintenance worker signed the work authorization permit.

h. 9:19-9:26 am: Maintenance personnel initially attempted to remove naphtha from a drain valve (valve I; Figure 4) in the blind flange downstream of the naphtha stripper level control valve (valve D), where the spool piece was previously removed. No material was observed coming from the drain line (connected to valve I).

i. The workers attempted to wedge the flange open just upstream of the control valve (valve D). No material was observed coming from the flange.

j. 9:40 am: Before the line was drained or isolation was verified, maintenance workers, the maintenance supervisor, and the No. 1 operator ascended the tower to begin cutting the naphtha piping with a pneumatic saw. The maintenance supervisor showed the workers where to make the initial cut into the piping.

k. 9:50 am: The maintenance supervisor left the unit.

l. 10:15 am: The maintenance supervisor returned to the unit halfway through the first cut into the naphtha piping.

m. The first cut was completed at an approximate elevation of 104 feet above grade (Figure 6). The crane was used to remove the top 9-foot section of the piping.

n. The maintenance supervisor directed a second cut on the naphtha piping at an elevation of 79 feet above grade (Figure 6). The cutting was stopped when the blade pierced the pipe and a small amount of naphtha began to leak from the line.

o. The maintenance supervisor attempted to locate the liquid level in the line by tapping on the pipe with a hammer and listening to the change in sound. He believed that the naphtha level was just above the location of the second cut.

p. A third attempt was made to drain the piping at the location of the flange upstream of the naphtha stripper level control valve (valve D). No material was observed coming out of the flange. The maintenance supervisor and a mechanic attempted to use a scraping tool to unplug the line at the flange; however, the tool did not penetrate the hardened material plugging the piping.

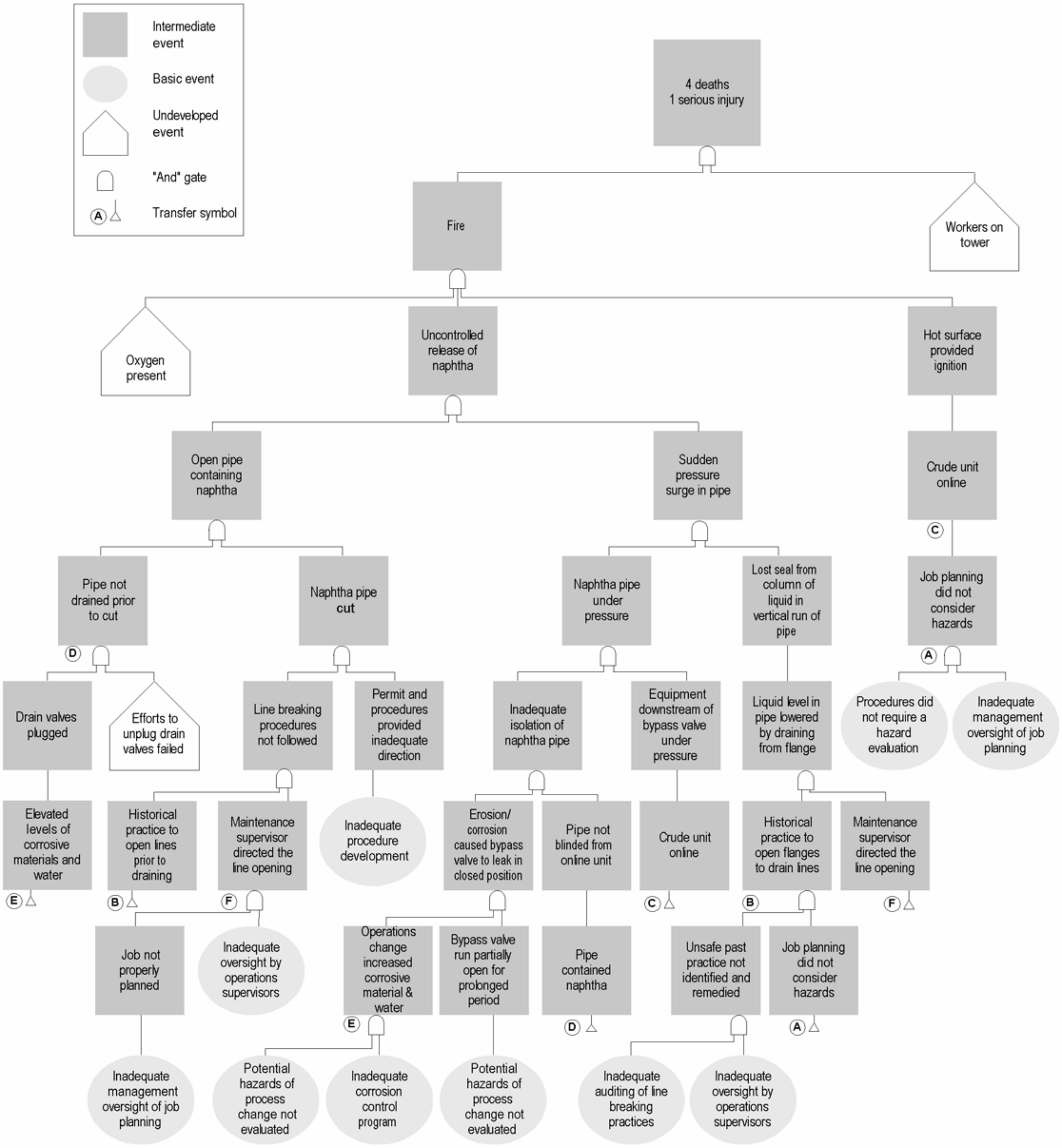
q. 11:00-11:30 am: The maintenance crew broke for lunch, after which the maintenance supervisor discussed possible drain points and directed the workers to drain the piping from the flange closest to the fractionator (flange 2).

r. 11:45 am: The next attempt to drain was initiated at the base of the vertical run of piping close to the fractionator (flange 2), at an elevation of 38 feet above grade. Naphtha was drained into a plastic pan with the flow directed by plastic sheeting. The naphtha was suctioned from the pan with a hose connected to the vacuum truck, which was parked at ground level (Figure 4).

s. 12:18 pm: Naphtha started to flow very rapidly from the line at the open end of the pipe. Hot equipment surfaces most likely ignited the naphtha. The resulting fire engulfed workers on the fractionator tower, killing four men and seriously injuring another.

APPENDIX B: Logic Tree Diagram

Tosco Fire, Avon Refinery



APPENDIX C: Executive Summary of The Hendrix Group, Inc., Report

This report documents the result of a technical review of documents associated with a naphtha leak and subsequent fire at the No. 50 Crude Unit at Tosco Refining Company's Avon Refinery located in Martinez California and the corrosion related and mechanical integrity issues that contributed to the fire. The results of the review showed that:

- The cause of the naphtha line leak precipitating replacement of the line was erosion-corrosion due to aqueous ammonium chlorides. The naphtha line leak, pluggage of the bleeder valves at the naphtha line control valve loop and erosion-corrosion of the bypass valve were all contributing causes leading to the incident. The control valve piping and bleeder valve pluggage and erosion-corrosion of the by-pass valve made the consequence of the incident greater, based on making draining more difficult and contributing to a greater amount of flammable liquid in the line than would otherwise be the case. The valve leak, the pluggage and the control valve erosion-corrosion were all due to the elevated levels of corrosive materials.
- Inadequate desalter operation with heavy crude slates directly contributed to the naphtha line corrosion by allowing excessive water and hydrolyzable chlorides to enter the fractionator tower, forming corrosive, acidic water in the top of the tower.
- Water slugs entering the tower, largely from inadequate dehydration of the crude feed by the desalters, caused tower upsets and water flooding of tower upper trays, resulting in water in sections of the tower where it normally would not be expected, including the naphtha draw line. However, there was significant available evidence to suggest the potential for corrosion of the naphtha draw line, including: (a) Tosco incident reports describing desalter problems with attending consequences of plant wide corrosion, (b) documented corrosion of fractionator tower trays in the vicinity of the naphtha draw line, (c) previous incidents of corrosion in the naphtha stripper and bottoms piping and, (d) having to drain water from the fractionator tower reflux line.
- Accelerated corrosion in the Main Fractionator and in associated overhead equipment had been a problem since the early

1980's. Tosco did not modify their corrosion control program to address continued equipment corrosion associated leaks.

- Tosco's mechanical integrity and inspection program failed to predict and locate corrosion problems before they resulted in leaks or emergency on-stream repairs. It was unclear from Tosco's inspection documentation what schedules were in place to conduct thickness surveys on the Naphtha Stripper draw line. Tosco had classified the line as a Class 1 line, with a maximum next inspection interval of 5 years, based on API 570, Piping Inspection Code. However, in their Piping Corrosion Management System (PCMS) documentation, (8/7/99) they appeared to list as much as a ten-year next inspection interval for the line. An inspection deficiency contributing to the incident, was the lack of a sufficient PCMS database at the time of the incident permitting corrosion rate determination.
- Failure of the corrosion control and corrosion monitoring programs to prevent events leading to the incident by practicing predictive inspection were symptomatic of: (a) inadequate management oversight, (b) inadequate or non existing documentation supporting SFAR-PSM-j, Mechanical Integrity, (c) insufficient inspection data documentation, (d) lack of proper inspection execution and, (e) inadequate communications between the mechanical integrity department and Unit 50 operations personnel.

APPENDIX C

PUBLIC COMMENTS ON THE DRAFT EIR AND RESPONSES TO COMMENTS

Responses to Public Comments on the Draft EIR

I. Piecemealing/Cumulative Impacts

Comment: Rules 11-18, 12-16, and 13-1 are part of the Air District's Refinery Strategy and the DEIR should contain a cumulative analysis reflecting the overall "Refinery Strategy" Project to avoid piecemealing. CEQA prohibits such a piecemeal approach and requires review of the projects as a whole, including any other existing and foreseeable future regulations affecting refineries. The DEIR should also include a discussion of the limitations on discussion of environmental impacts specific to those factors not known or beyond the scope of the rule(s) proposed.

CCEEB, Chevron, Phillips 66, Shell, WSPA

Response: Insofar as the comment suggests that a cumulative impact analysis is appropriate for adoption of Rule 12-16, the Air District agrees and has included such an analysis in the EIR for the rule. However, the Air District disagrees that a failure to review all rules that have been considered for implementation of the Refinery Strategy constitutes segmentation or "piecemealing" for CEQA purposes.

The Air District believes the manner in which it has considered and adopted rules implementing the Board of Directors' October 2014 Refinery Strategy Resolution does not constitute piecemealing for two primary reasons. First, because the Refinery Strategy Resolution was not itself a CEQA project, it follows that rules implementing it are not susceptible to being piecemealed as part of a larger CEQA project. Second, under established judicial precedent, because each rule implementing the Refinery Strategy Resolution has independent utility, analyzing these rules separately is appropriate, and does not constitute piecemealing.

Comments advancing the piecemealing argument characterize the Refinery Strategy as qualitatively different from the Air District's historic approach to regulating refinery emissions. The Air District's approach to rulemaking and the methodologies used are no different than in the past, and the rules themselves have the same independent utility as rules pre-dating the Refinery Strategy. The difference in rulemaking activity undertaken pursuant to the Refinery Strategy is at most quantitative over a given period of time, but there is no qualitative difference that would the larger policy effort referred to as the "Refinery Strategy" is itself a CEQA project.

For almost 50 years, virtually since its inception as an agency, the Air District has been adopting rules applicable to Bay Area refineries. Prior to 2015, at least 22 rules developed, adopted, and from time to time amended by the Air District were applicable to refineries. Notwithstanding this extensive historical effort, regulation of refinery emissions was neither complete nor static prior to the Board of Director's 2014 adoption of the Refinery Strategy. This is evident, for instance, in the 2010 Clean Air Plan. The Clean Air Plan is a scoping document for rulemaking efforts the Air District anticipates over the next few years. The 2010 Clean Air Plan Stationary Source Measure 8 –

addressing reduction of SO2 from petroleum coke calcining – was later identified as a component of the Refinery Strategy and was ultimately adopted as Rule 9-14. Stationary Source Measure 18 -- "Revisions to the Hot Spots Air Toxics Program" -- was described in the 2010 Clean Air Plan as an enhancement of the Air District's hot spots program similar to draft Rule 11-18 that is currently under consideration for refineries as well as other stationary sources. Rule 12-15 -- adopted in 2016 and requiring enhanced emissions information from refineries -- was not identified in the 2010 Plan, but was included as "Action Item 4" in the Air District's 2012 Work Plan (a list, required pursuant to Health & Safety Code Section 40923 of regulations planned for adoption in the coming year).

The overlap between the 2010 Clean Air Plan, the 2012 Work Plan, and the Air District's efforts to implement the Refinery Strategy effort demonstrates the continuity of the Air District's efforts to reduce refinery emissions before and after the Board of Director's 2014 adoption of the Refinery Strategy. It could not reasonably be argued that the cumulative historic effort to regulate refinery emissions is a unified CEQA project such that evaluating each rule separately constitutes piecemealing. Such an argument would advocate for the impossible, namely, that the Air District should have at some point in the past foreseen and analyzed under CEQA the future of refinery regulation. The piecemealing argument posits a qualitative break in this historical continuity marked by the October 2014 Board Resolution. This begs the question: what distinguishes activity implementing the Refinery Strategy from the decades of continual regulatory development that preceded it?

The Air District's legal analysis starts with the proposition that if the Board Resolution was not itself a CEQA project, then it has no implication for what constitutes the "whole of the action" under CEQA. Put another way, if the 2014 Board Resolution has no significance under CEQA, then it did not have potential to change the CEQA significance of anything else, including the rules identified as making progress towards the policy goal announced in the resolution.

The 2014 Board Resolution was a statement by the Air District Board of Directors setting an aspirational goal to achieve a certain degree of emissions reductions from refineries within a certain period of time. A resolution is the expression by the members of the Air District governing board of a position or sense. It has no regulatory effect, and is neither a necessary nor sufficient basis for any subsequent action that might have regulatory effect.

A "project," for CEQA purposes, is "an activity which may cause either a direct physical change in the environment, or a reasonably foreseeable indirect physical change in the environment." The Refinery Strategy Board Resolution fails to meet this definition because it is not an "activity" at all. Unlike a general plan for land development or an agreement to allocate funds, the Refinery Strategy Board resolution is not a legal or functional prerequisite to further rulemaking.

The commenters may be arguing that, although the 2014 Refinery Strategy Board Resolution is not itself a project, it was reasonably foreseeable that rules implementing it would be adopted, and that this foreseeability is enough to create a larger CEQA project corresponding to the Refinery Strategy effort. However, as explained above, it was foreseeable that additional rules regulating refinery emissions would be developed by the Air District even without the Board Resolution. Such rules were in development prior to the Board Resolution, and some of these rules later became identified as part of the Refinery Strategy. Put another way, there is nothing in the record to suggest that, with State air quality goals still unattained, the refineries (as among the largest stationary sources of air pollution in the Air District) would not have been subject to future regulation but for the Refinery Strategy.

Separate CEQA analysis of the rules implementing the Refinery Strategy is proper because each rule has independent utility. See, e.g., *Del Mar Terrace Conservancy, Inc. v. City Council of the City of San Diego,* 10 Cal.App. 4th 712 (1992). Air District rules generally have independent utility because each operates independently of the others to reduce emissions from a specific operation, and because the emissions reduction from each rule advances the goal of reducing emissions regardless of whether another rule is adopted. This is generally true of the rules implementing the Refinery Strategy.

A prior version of Rule 12-16 was proposed for adoption in late 2015 contemporaneously with a prior version of 12-15. The Air District at the time judged the two rules to be functionally interrelated enough to evaluate them together in the same EIR. Specifically, certain enforceable mechanisms in Rule 12-16 were dependent on information gathered through Rule 12-15. Neither rule was adopted in the form it was proposed in 2015. Rule 12-15, which was never considered functionally dependent on Rule 12-16, was subsequently revised and adopted in April of 2016. Rule 12-16 has also been substantially revised since being proposed in 2015. There remains some functional relationship between the two in that Rule 12-16 relies on information gathered through Rule 12-15. Given that Rule 12-15, being primarily informational, was assessed in an EIR to have negligible environmental effect, it is unlikely that considering these effects in combination with Rule 12-16 would alter the CEQA analysis of Rule 12-16. It should be noted, however, that Rule 12-15 is being considered as part of the cumulative impacts analysis for Rule 12-16.

Putting aside Rules 12-15 and 12-16, the Air District has at times sought to combined various Refinery Strategy rules together into common CEQA documents. In each of these combined CEQA analyses it was noted that rules were being combined for administrative convenience only, and that that no inference was created that the rules were functionally interdependent. If there is no larger CEQA project encompassing these various rules, then the significance of combining them in one CEQA document is a purely administrative. Nor is it otherwise legally improper to combine distinct CEQA projects into one CEQA document. See, *Neighbors of Cavitt Ranch v. County of Placer,* 106 Cal. App. 4th 1092 (2003).

The practical difficulties in analyzing all Refinery Strategy rules in one CEQA analysis would be insurmountable. If, for instance, CEQA analysis should have been completed prior to the Board announcing the 20% reduction policy goal, such an analysis would have been pure speculation. Analysis of an emissions reduction figure is an empty exercise unless the details of how those reductions will be achieved are known. The Refinery Strategy Board Resolution was a directive to staff to attempt to develop such details. It is implausible that CEQA requires the governing board of a public agency to conduct a CEQA study prior to issuing such a directive to its staff.

As a practical matter, analyzing all Refinery Strategy rules together under CEQA could only occur if all the rules were proposed simultaneously. Resource constraints alone make such a scenario highly unlikely. Resources aside, technically complex rules such as those applicable at different refinery operations will develop at a different pace and on different schedules. The development of rules comprising the Refinery Strategy illustrates this. The Refinery Strategy effort has been in continual flux as new information and analysis (much of it coming from the public and the refineries themselves) has emerged. The iterative process of proposing ideas, soliciting feedback, and revising proposals is appropriate and normal for development of a single rule. This iterative nature is multiplied as additional rules are developed during the same time frame. With several rules simultaneously under consideration, an attempt to conduct CEQA analysis on the totality of such an effort would result in an endless loop of revision and recirculation of CEQA documents, effectively foreclosing the adoption of any rules under consideration. The Air District believes CEQA intends no such result.

Comment: Action on Rule 12-16 should be delayed. A DEIR should be prepared for both Rules 12-16 and 13-1 on the current schedule for Rule 13-1 so that both rules may be considered for adoption in September.

Health Professionals, R. Lin, et al.,

Response: Air District staff has expressed misgivings with respect to Rule 12-16 in its current form and does not believe a combination of both rules would resolve the issues raised; in fact, such a confluence may serve to exacerbate those issues. One of the stated purposes of Rule 12-16 is to "…discourag[e] investment in new refinery equipment that would lead to increased emissions of GHG, PM, NOx, or SOx from Bay Area refineries." This objective is at cross-purpose to that of Rule 13-1, which is to limit the carbon intensity (the ratio of mass of GHGs emitted to the volume of refinery inputs, e.g., crude oil) of refining petroleum. Carbon intensity limits would result in improved refinery efficiency and allow for production increases, provided the refinery operated within its intensity limit. Further, Rule 13-1 contains, as a compliance alternative, GHG emissions limits that are at least as if not more stringent than those contained in Rule 12-16. The option of the intensity and emission limits provide greater flexibility in compliance than Rule 12-16. Finally, the criteria pollutant limits in Rule 12-16 conflict with Air District NSR rules and may be considered arbitrary during a judicial review.

II. Overall Objective/Environmental Setting/Background

Comment: The project description, objectives, and environmental setting need to be revised to reflect a well-defined need and objective. The DEIR does not establish a need or clearly and accurately define the purpose/objective of Rule 12-16. The DEIR does not sufficiently explain why the Rule meets or fails to meet that need and purpose.

R. Lin, et al,

Response: The Air District disagrees with this statement. The project description clearly describes Rule 12-16, the objectives were drafted from recommendations by CBE and their associates, who advocated this version of Rule 12-16. As for the environmental setting, he Air District's disagreements with the commenters specific concerns about the environmental setting portion of the document are discussed below.

Comment: The DEIR should also demonstrate how an emissions cap would reduce the emission intensity of the production of transportation fuels.

Shell

Response: As written, Rule 12-16 would have little impact on a refineries emissions intensity, unless a refinery improved its energy efficiency, which in turn would improve its emissions intensity.

Comment: There is a lack of clarity throughout the DEIR when using the terms "project" and "alternatives."

WSPA

Response: The Air District believes that the DEIR is sufficiently clear on these issues.

Comment: The air monitoring data presented doesn't seem to support this regulation for refineries, but rather that further regulation is needed for mobile sources and in the Eastern District (Livermore, Patterson Pass, and San Ramon). The DEIR does not explain the expected impacts of this regulation on refineries, the communities surrounding the refineries, or the areas with the most exceedances of ambient air quality standards. The project objective should include involvement of affected businesses and discuss other refined products at a refinery.

Health Professionals, J. Griggs, L. Mejicanos, N. Mendoza, R. Lin, et al, S. Lee, Shell, T. Yu, WSPA

Response: Rule 12-16 would prevent refinery emissions from increasing above the emission limits, which represent the maximum emissions of each pollutant over a five-year period and an additional 7 percent buffer. As such, the Rule would not have an effect on the surrounding community, except for the potential to cause adverse environmental impact as is discussed in the DEIR. Because the rule addresses refinery emissions it is not necessary to discuss each refineries product slate because the impact of the product slate is reflected in each facility's emissions profile that is characterized by the emissions inventory.

Comment: The Environmental Setting should include discussions about expected changes in emissions at refineries and the effect on environmental justice communities. Refineries commented that emissions are expected to decline due to existing limits and regulations. Others contend that emissions will increase due to refining lower quality oils in the Bay Area, accidents, expansion projects, increased exports, and inadequacy of source-level pollution limits.

Health Professionals, R. Lin, et al, WSPA

Response: CEQA guidelines, Section 15125(a) under Environmental Setting states: "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 description of the environmental setting shall be no longer than is necessary to an understanding of the significant effects of the proposed project and its alternatives." The commenters' assertions that the environmental setting should:

- Include the objectives of Rule 12-16; the trend toward refining increased volumes of lower quality oils in the Bay Area;
- Discuss the industry trend to refining lower quality oils in the Bay Area; recent and foreseeable refinery expansion projects or capacity to refine greater quantities of lower quality oils in the Bay Area;
- Include an estimate of the potential increase in combustion emissions (GHGs, PM, NOx and SOx) that Rule 12-16 is designed to limit; and the potential for emission increases as a result of accidents that Rule 12-16 is designed to prevent; disclose that aggregating individual source limits does not produce effective, overall, facility-wide pollution controls on Bay Area refineries;
- Discuss that there are no safe levels of particulate matter and, given high baseline pollution, every $PM_{2.5}$ exposure increment will contribute to increased risk of mortality, morbidity, and lost productivity for Bay Area residents;
- Recognize as part of the current landscape that failure to prevent increased refinery emissions will have environmental justice repercussions since they will predominantly occur in communities where residents are low income and/or are people of color and already disproportionately burdened by poor underlying health and multiple-source pollution exposures;

Are not supported by CEQA. CEQA Guidelines Section 15125(d) states that… "[t]he EIR shall discuss any inconsistencies between the proposed project and applicable general plans, specific plans, and regional plans." The DEIR addresses this aspect of CEQA in Sections 3.2.1, 3.3.1, 3.4.1, and 3.5.1 of the document.

Comment: Revise sections of the Existing Regulatory Setting to include a discussion of State climate and other relevant pollution reduction policies, and include relevant vulnerability factors to assess disadvantaged communities' cumulative exposure to pollution impacts on vulnerable populations exposed to refinery emissions regionally, and, specifically, those in communities near Bay Area refineries.

R. Lin, et al

Response: Section 3.3.3.2 State Regulations of the DEIR contains a comprehensive listing of State laws and regulations affecting GHGs, including a discussion of AB 197 which requires CARB, when adopting rules and regulations, to achieve emissions reductions to protect the State's most affected and disadvantaged communities, CARB shall consider the social costs of the emissions of GHGs, and prioritize emission reduction rules and regulations that result in direct emission reductions at large stationary sources of GHG emissions and direct emission reductions from mobile sources.

Comment: Understanding the environmental effects of the proposed action, therefore, requires information about the baseline state of change in refinery emissions caused by changes in refinery oil feed quality and quantity.

CBE

Response: There is no evidence of increasing GHG emissions since these data were collected in consistent fashion by CARB beginning in 2008. Highest GHG emissions from 4 of the 5 refineries was in 2008, and the fifth refinery's highest GHG emissions was in 2012. There is also no evidence of increasing criteria pollutant emissions. Emissions of NO_X and SO_2 have consistently declined over time and PM emissions have remained steady, once one accounts for changing measurement techniques.

III. Project Description/Identifying Affected Sources

<u>III.1 Project Description</u>

Comment: The DEIR's project description is vague, inaccurate, and incomplete and this renders the analysis of significant environmental impacts (and dismissal of other resource topics) inherently unreliable. The District must revise and recirculate the DEIR to address the issues with the project description.

CCEEB, L. Mintzer, R. Lin, et al., Shell

Response: Staff disagrees. The DEIR describes Rule 12-16 quite clearly, listing the types of facilities and sources rule would be affected; the requirements of the rule, including emissions limits and implementation schedules, and the types of control equipment that could be used to comply with the requirements of the rule and the environmental effects. The comment that the IS is incomplete and makes no attempts to identify affect resources is not correct as explained below. Further, none of these concerns were raised during the 30-day public comment period on the NOP/IS.

Comment: The DEIR prejudices consideration of Rule 12-16 by mislabeling it "CBE's" proposal.

R. Lin, et al

Response: As stated in the DEIR and the staff report, proposed Rule 12-16 represents a policy proposal made by CBE, et al. and is being presented at the direction of the Air

District's Board of Directors. This is an accurate description. It should be noted that staff has publicly expressed concerns regarding the efficacy and legality of the Rule 12-16 in its current form and went so far as to list those concerns to CBE along with possible solutions with which to revise the proposal; CBE opted not to incorporate staff recommendations. While it is true that Air District staff originally proposed a rule numbered "12-16" in the fall of 2015, that 12-16 and the one currently being considered are entirely different proposals that share only a common enumeration and, further, the current proposal is not and should not be considered an iteration of the 2015 rule that was proposed and subsequently withdrawn.

Comment: The DEIR failed to disclose these existing baseline environmental conditions. In particular, its air quality analysis (see DEIR pp. 3.2-1 through 3.2-14) provided no information whatsoever about these oil quality-driven changes in refinery air emissions. In other words, the DEIR failed to disclose the problem Rule 12-16 is needed to solve.

The District could have disclosed and evaluated the baseline state of change in refinery combustion emissions caused by changing refinery oil feed quality and quantity in the DEIR.

The DEIR could have concluded that increasing combustion emissions caused by refining higher-emitting grades of oil in greater amounts is an existing baseline condition in the region.

CBE

Response: As mentioned above, there is no reliable evidence that refinery combustion emissions are increasing.

Comment: The DEIR concluded that if Rule 12-16 is not adopted other measures will reduce refinery combustion emissions (DEIR at 4-6) without disclosing or evaluating any information about the scale of the emissions increase that Rule 12-16 could prevent. This conclusion is not credible. The DEIR's failure to evaluate the refinery combustion emission increments the proposed action could prevent renders its assertion of this conclusion misleading, unsupported, and incorrect.

Air District staff could have estimated the refinery combustion emission increments that the proposed action could prevent in the DEIR.

The DEIR failed to provide adequate information about refinery emissions the proposed action could prevent, and failed to disclose readily available information that, when disclosed and considered, reverses the DEIR's conclusions regarding Rule 12-16.

CBE

Response: The Air District shares CBE's concerns about the potential for increasing combustion emissions due to changes in feedstock, but it is not an appropriate topic for a CEQA analysis.

Future crudes imported to Bay Area refineries will be replacing existing mixes, which can currently be heavy and sulfurous, depending on the design of the particular refinery. Extrapolation of more intensive processing requirements beyond existing permit limits and existing equipment limits is not valid. Existing permits and equipment limitations prevent the ability to significantly increase processing intensity. That said, Air District Staff agrees that refineries are currently able to apply for permits for their facilities to process heavier and more sulfurous crude which would likely lead to increased combustion emissions. We do not agree that it is possible to accurately predict the extent of those emission changes. This type of knowledge is highly speculative. While refineries may purchase heavier, more sulfurous crudes, such as Canadian tar sands, they may also purchase lighter, less sulfurous crude such as shale oil depending on dynamic relative pricing at the time. Given the speculative nature of such an analysis, it's not appropriate to include in a CEQA document.

Comment: The DEIR failed to disclose or evaluate the local health benefits of preventing exposures to that excess air pollution.

Air District staff could have quantified the health benefits of Rule 12-16 in the DEIR. For example, among other health benefits, it could have estimated the premature deaths of adults averted by the proposed action. Estimates of premature deaths that could be averted by the proposed action, regionally and within 2.5 miles of refinery fence lines.

CBE

Response: A response to a previous comment detailed why it is too speculative to include estimates of future emission increases due to crude slate changes in the CEQA analysis. Further extrapolating that estimate to include how those emission changes would translate into community exposure and health impact is similarly too speculative for a CEQA document and not appropriate to include.

III.2 Control Technologies

Comment: The DEIR does not adequately address the environmental impacts of the rules because the equipment that will be installed in order to comply with the rules has not been determined yet.

L. Mintzer

Response: While Rule 12-16 does not specify control equipment to ensure compliance, it is reasonable to assess the limited number of potential compliance scenarios and evaluate the control equipment available to ensure compliance under those scenarios. This is what the DEIR has done in its evaluation of use of selective catalytic reduction units and wet gas scrubber.

Comment: The DEIR lacks adequate and consistent identification of control equipment (including control equipment of GHGs) that may be used to comply with Rules 11-18 and 12-16 and the associated detailed impacts analysis (including soils analysis, noise analysis, utilities and service systems) of that control equipment that could have significant impacts.

L. Mintzer, Shell

Response: The DEIR developed an extensive and comprehensive listing of control technologies that could be employed to comply with both Rules. These options are clearly listed in Chapter 2: Project Descriptions.

Comment: Revise the DEIR to disclose the no cost, no impact option of compliance with Rule 12-16 and remove all references to and analysis of the installation of pollution control equipment as a necessary compliance option for Rule 12-16 and, also, any discussion of such associated significant impacts.

CBE, R. Lin, et al.

Response: It is reasonable to assume that at some point a refinery's emissions may be on the verge of exceeding or exceed its emission limits for any one of the pollutants addressed by Rule 12-16; if this potentiality were not the case, there would be no need for Rule 12-16. In evaluating this potential, staff determined that there were three scenarios under which adverse environmental impact could occur—the installation a selective catalytic reduction (SCR) unit to control NOx emissions and the installation and operation of a wet gas scrubber to control SO_2 emissions. The construction of both an SCR and WGS could result in significant NOx emissions from the operation of construction equipment as presented in Tables 3.2-16, 3.2-19, 3.2-20 in the DEIR. Additionally, the operation of a wet gas scrubber at a refinery could result in significant water demands as presented in Table 3.5-1 of the DEIR. Although the evaluation of these scenarios does not guarantee their occurrence, the Air District would be remiss not consider their potential impact the EIR.

Comment: The DEIR assumed that refinery emissions will increase, refiners will install costly new engineered controls to capture a larger fraction of those emissions and meet the limits in Rule 12-16, and those costly new controls will cause significant impacts that cannot be mitigated. The DEIR provided no evaluation of the strength of the incentive this option provides refiners to avoid new costs, analysis of this option as mitigation for the "unmitigable" impacts alleged, or consideration of whether Rule 12-16 may be necessary to achieve emissions cuts that other regional and state air quality and climate measures seek. The DEIR then compounded its error by concluding that the proposed action is not part of an environmentally superior alternative.

District staff could have compared all Rule 12-16 compliance options in the DEIR, including continuing current operations without refining lower-quality oil or expanding production capacity, the DEIR could have concluded that a no-cost compliance option which is consistent with other plans and policies would not require any change to existing equipment or operation, and could thereby avoid any potential negative environmental impact of implementing Rule 12-16.

CBE

Response: The purpose of the CEQA is to evaluate potential negative impacts from the proposed project. Since limiting throughput to comply with Rule 12-16 does not cause any negative environmental impact, it is not appropriate to evaluate that response to the Rule in a CEQA analysis. With respect to the alternatives analysis, since draft Rule 13-1 does not directly limit criteria pollutants, it avoids the possible negative environmental impacts of Rule 12-16.

Comment: The DEIR did not provide adequate information about any of these topics:

(1) Existing baseline conditions that affect oil refining emissions in the Bay Area;
(2) The potential oil refining emission increments that the proposed action to implement Rule 12-16 could prevent;
(3) The long-term local health hazards associated with refinery emissions that Rule 12-16 could prevent;
(4) The short-term “episodic” local health hazards associated with refinery emissions that Rule 12-16 could prevent; and
(5) The potential environmental impacts that could occur as side effects of implementing this action.

CBE

Response: As detailed in in previous responses, Air District staff disagrees with the assertion that the EIR should have included projected emission increases and health impacts that may occur should Rule 12-16 not be adopted. The additional assertion that Rule 12-16 would prevent episodic local health hazards is similarly speculative.

Comment: Lower quality oil feeds increase process severity, the frequency of equipment failures and process gas imbalances, the volumes of flammable and contaminated materials that are available to be released in those failures and imbalances, and thus the frequency and magnitude of refinery emission episodes.

CBE

Response: This analysis is overly speculative and not appropriate for a CEQA analysis. Furthermore, it is not supported by the facts. Any change of crude requires thorough review of potential operational or corrosion issues, as required by Process Safety Management – Management of Change processes:

- Increase in processing severity is unlikely as crude mix must remain within existing permit and equipment limits.
- Process gas supply-demand balance must be anticipated and accommodated in the Management of Change process.
- Expectation of an inadequate or failed Management of Change process is highly speculative.

IV. Alternatives Analysis

Comment: The District's failure to include as alternatives each permutation of all possible rule combinations is fatal to its analysis in the DEIR.

CCEEB

Response: Under the CEQA Guidelines, there is no requirement for the alternatives analysis to "…consider every conceivable alternative to a project. Rather it must consider a reasonable range of potentially feasible alternatives that will foster informed decision making and public participation." Section 15126.6(a) of the CEQA Guidelines.

Comment: The Alternatives should have included a scenario where a facility or refinery is shut down.

Shell

Response: It is unclear if the comment refers to 1) a refinery closure due to the requirements of either Rule 11-18 or 12-16 or 2) the potential effects of a California refinery closure due to other reasons and the subsequent response by Bay Area refineries and the related environmental impacts in relation to the two rules. For the first case, there is no reason to believe that the impacts of either rule would result in the closure of a Bay Area refinery—both rules are crafted in such a manner to ensure that affected facilities are able to comply and avoid undue socioeconomic harm. Under the second interpretation, the closure of any California refinery would result in all the remaining refineries increasing production to ensure meet the state demand in refinery products are met. The 2015 closure of the ExxonMobile refinery in Southern California resulted in a 10 percent reduction in production that was met by the other California refineries and imports from out-of-state. Even under these conditions, refineries in the Bay Area did not exceed the GHG caps in Rule 12-16. That said, a closure of this type, while possible, is highly speculative and, therefore, not appropriate for consideration in this environmental assessment.

Comment: The evaluation of alternatives to Rule 12-16 are limited to only one proposal for establishing the caps. The Air District does not provide support for the proposed 7 percent threshold allowance, nor does it consider whether an alternative to setting the caps at any other level might eliminate concerns of fuel shortages in the event of unanticipated long-term temporary loss of production or the ability to provide future adequate fuel supply to the local market. These consequences and their potential environmental impacts should be evaluated and considered so that the possibility of unanticipated leakage of emissions is minimized.

Shell

Response: The Air District conducted an analysis on the year-to-year variation of refinery GHG emissions in the ARB greenhouse gas reporting data and found that the average facility GHG emissions variability was slightly larger than 6 percent during recent years. This, together with the analysis of refining capacity detailed elsewhere in this document are sufficient to document that the GHG cap proposed in Rule 12-16 minimizes the risk of leakage.

Comment: The DEIR fails to adequately discuss the environmentally superior alternative. Revise the DEIR's findings of significant impacts that arise from the construction and operation of pollution abatement equipment to comply with Rule 12-16 (in all areas, Air Quality, GHGs, Hazards and Hazardous Materials, Hydrology, Water Quality, and Utilities,) and revise each subsequent section of the DEIR that had relied on those misidentified significant impacts, including consideration and comparison of Alternatives.

R. Lin, et al.

Response: It is reasonable to assume that at some point a refinery's emissions may be on the verge of exceeding or exceed its emission limits for any one of the pollutants addressed by Rule 12-16; if this potentiality were not the case, there would be no need for Rule 12-16. Because this potentiality exists and would result in significant impacts, it DEIR could not find that Rule 12-16 in its current form, would be the environmentally superior option.

Comment: The "No Project" alternative should include: 1) an evaluation of the foreseeable climate and local pollution impacts that could result from the several Bay Area refinery expansion projects that enable the refining of lower quality oil feedstocks; 2) how the Air District's regulations and the State's climate policies with and without Rule 12-16 can or cannot reduce such impacts; a discussion of whether the "infrastructure inertia" created by the commitment to major capital refinery investments in process changes could enable more refining of more climate-disrupting feedstocks for the foreseeable future; and 3) an analysis of the subsequent opportunity cost of a sustainable energy future.

R. Lin, et al.

Response: Section 15126.6(e)(2) of the CEQA Guidelines states that "[t]he 'no project' analysis shall discuss the existing conditions at the time the notice of preparation is published…, 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." There substantial debate on what types of feedstocks refineries will use in the future. This type of knowledge is highly valuable and, by nature, speculative. While refineries may purchase heavier, more acidic crudes, such as tar sands, they may also purchase lighter, sweeter shale oil crude to balance the impacts of tar sands or because of the price of either. It is impossible to determine how refiners would react to the changing landscape of crude oil commodities market and such speculation is inappropriate for this CEQA review.

Comment: Inclusion of draft Rule 13-1 in the alternatives analysis is highly speculative because it is still in development and it is premature to make findings in this DEIR regarding how effective implementation of any rule in conjunction with Rule 13-1 may prove.

R. Lin, et al.

Response: Section 15126.6(a) of the CEQA Guidelines states: "An EIR shall describe a range of reasonable alternatives to the project… which would feasibly attain most of the basic objectives of the project but would avoid or substantially lessen any of the significant effects of the project, and evaluate the comparative merits of the alternatives. Further, Section 15126(f) states: "The range of alternatives required in an EIR is governed by a "rule of reason" that requires the EIR to set forth only those alternatives necessary to permit a reasoned choice." The EIR is only required to present feasible [with emphasis] alternatives (e.g., potential options, not absolutes) that would avoid or substantially lessen any of the significant effects to foster informed decision-making and public participation. Both Draft Rules 11-18 and 13-1 are currently under development by Air District staff and are included in the recently adopted 2017 Clean Air Plan. From these perspectives, Rules 11-18 and 13-1 should not be viewed as "speculative" and the combination of both presents a reasonable alternative through which to compare and evaluate the merits of proposed Rule 12-16. Draft Rule 13-1 (in combination with Rule 11-18) is a reasonable alternative to be considered in comparison to Rule 12-16 in its current form.

V. Significant Environmental Impacts

Comment: The DEIR does not support adoption of Rule 12-16 since there would be significant environmental impacts (particularly water usage), even after mitigation. The DEIR does not demonstrate that any air quality benefit outweighs the significant impact, nor does it adequately detail mitigation measures or objective criteria for measuring success.

CCEEB, Chevron, WSPA

Response: Staff agrees that the DEIR does not support a finding that Rule 12-16, as currently drafted, should be adopted. However, revisions to the proposed rule could be made that would eliminate the environmental deficiencies and allow its adoption.

VI. Missing Topics/Topics Not Adequately Addressed

VI.1. Hazardous Materials

Comment: The hazard analysis needs to evaluate the following issues: presence and potential disturbance of asbestos-containing materials and/or lead paint, potential disturbances of areas known to be contaminated, fuel transportation hazards from shipments of fuels from other locations, and potential hazards associated with control devices ((1) the increased use of caustic or lime for the LoTOx technology, and (2) the catalysts used for selective oxidation catalyst as listed in Table 3.4-1).

Shell

Response: This comment incorrectly states that the DEIR did not include hazards analyses for the increased use of caustic or lime for the LoTOx technology or the catalysts used for the selective oxidation catalyst technology. The LoTOx technology is typically used in conjunction with a wet gas scrubber and NaOH or soda ash are the most likely caustics that would be used. As indicated in Section 3.4.4.6 of the DEIR, neither NaOH nor soda ash would cause or contribute to exceedances of any applicable hazards and hazardous materials significance thresholds. Similarly, the analysis in Subsection 3.4.4.7.2 concluded than accidental releases of NaOH or soda ash during transport would also not cause or contribute to exceedances of any applicable hazards and hazardous materials significance thresholds.

With regard to the selective oxidation catalyst technology, as noted in the DEIR, a typical SRU/TGU system is not expected to require more than several hundred pounds of selective oxidation catalyst modules per year. As a result, delivery of catalyst modules can be accomplished in one truck trip. Based on their chemical properties, sulfur oxidation catalysts are not expected to pose significant adverse health or physical hazard impacts during use. See DEIR Subsection 3.4.4.7.1 for additional information.

As noted in the Initial Study, implementing Rule 12-16 would potentially result in the installation of additional air pollution control equipment which is not expected to create substantial quantities of solid or hazardous waste. Waste streams from refineries would be processed similarly as current methods, so no significant impact to land disposal facilities would be expected. As a result, no further analysis of hazardous waste impacts was required.

VI.2. Water Quality

Comment: The evaluation of impacts to water quality should be revised. The analysis should address the potential impacts from instances when wastewater from a wet scrubber is not treated and recycled to minimize water demand. Supporting information should be provided regarding potential increases in runoff from construction activities and water application rates for dust suppression.

Shell

Response: As noted in the DEIR, not all of the wastewater generated by air pollution control equipment would be discharged as wastewater. Some portion of the wastewater would likely be emitted as steam or is treated and recycled. Depending on the volume of potential wastewater discharged, if it is not within the percent variation allowed by the local sanitation districts, affected refinery operators may need to apply for revisions to their Industrial Wastewater Discharge Permit. Regardless of the facility, wastewater discharges from an industrial facility would be required to be discharged in compliance with the applicable wastewater discharge permits and, therefore, impacts would be less than significant. For additional information, refer to DEIR Section 3.5.4.2.

Comment: Insufficient information has been provided in the IS to support the conclusion that construction activities associated with control technologies would be limited in size, thus, limiting the potential for increases in runoff.

Shell

Response: The question in the Initial Study referring to potential water runoff impacts does not simply refer to increased runoff, it refers to increased runoff that may "exceed the capacity of existing or planned stormwater drainage systems…" Industrial facilities such as refineries are subject to a number of requirements regulating stormwater runoff. In particular, the State of California has been delegated authority to implement the Clean Water Act Storm Water Pollution Prevention Plan (SWPPP) provisions. The SWPPP also applies to water discharges from construction activities. The SWPPP requires that an affected facility be able manage stormwater runoff, which is expected to be substantially greater than runoff that may occur from dust control activities during construction. As a result, it was concluded in the Initial Study that Rule 12-16 would not create or contribute to runoff water that would exceed the capacity of the existing stormwater drainage systems at affected refineries. Based on this conclusion, no further analysis of potential water runoff impacts was required.

Comment: The scenario related to water usage for dust suppression was not fully substantiated, and the water application rates were unrealistic.

Shell

Response: Other CEQA documents evaluating construction air quality impacts control equipment have also made the assumption that the largest types of air pollution control equipment used to control refinery emissions include electrostatic precipitators, fuel gas treatment, and wet gas scrubbers. (See, for example, SCAQMD, 2010). The comment does not include any data or other information that identifies other air pollution control equipment that could be used to comply with Rule 12-16 and would require a construction footprint larger than 6,000 square feet.

As the comment notes, the analysis of water demand for dust suppression during construction uses conservative assumption. Using conservative assumptions to analyze environmental impacts is a standard practice that ensures that impacts are not underestimated.

VI.3. Socioeconomic Impacts

Comment: The DEIR fails to adequately analyze socioeconomic impacts, including the operational safety, flexibility, and sustainability of the refineries.

Chevron, Phillips 66, *R. Lin, et al., Shell*

Response: The socioeconomic impacts of the proposal are discussed in both the Staff Report and the associated Socioeconomic Impacts Analysis of Proposed Rule 12-16.

VI.4. Offsets/Cap and Trade

Comment: The DEIR presents a confusing analysis of GHG emissions and does not address whether Rule 12-16 would allow the use of Cap-and-Trade or other offset programs, and does not explain how the credits work with the Rule 12-16 cap.

CCEEB, Shell, WSPA

Response: Rule 12-16 is not expected to impact the use of Cap-and-Trade or other offset programs unless refineries wanted to increase capacity. Other responses in this document provide details on why the Air District believes the GHG limits in Rule 12-16 are consistent with the capacity operation of the refineries and that gasoline consumption on the West Coast is predicted to decline over time based on projections from the U.S. Energy Information Agency.

VI.5. Other Environmental Effects

Comment: The DEIR fails to have a section on environmental effects found not to be significant.

Shell

Response: CEQA Guidelines Section 15128 states that “An EIR shall contain a statement briefly indicating the reasons that various possible significant effects of a project were determined not to be significant and were therefore not discussed in detail in the EIR. *Such a statement may be contained in an attached copy of an Initial Study*.” (emphasis added) The Draft EIR complied with CEQA Guidelines Section 15128 because the Initial Study was included as Appendix A of the EIR.

Comment: The introduction to Section 3 notes that the DEIR provides analysis for a list of environmental areas, not all of which are provided in the report.

Shell

Response: Section 3.1 of the DEIR has been revised in the Final EIR to be consistent with the analyses in the document.

VI.6. Tribal Cultural Resources

Comment: The DEIR and Initial Study used an old Appendix G checklist and failed to include consideration of Tribal Cultural Resources.

Shell

Response: Tribal cultural resources were included in the evaluation of cultural resources. Public Resources Code §21080.3.1 states that that “(p)rior to the release of a negative declaration, mitigated negative declaration , or environmental impact report for a project, the lead agency shall begin consultation with a California Native American tribe that is traditionally and culturally affiliated with the geographic area of the proposed project if: (1) the California Native American tribe requested to the lead agency, in writing, to be informed by the lead agency through formal notification of proposed projects in the geographic area that is traditional and culturally affiliated with the tribe… To date, the District has not received a request from any California Native American tribe requesting formal notification, therefore, formal notification is not required. The NOP/IS was sent to the State Clearinghouse and no comments were received from Native American tribes and no request for formal consultation was received. Therefore, the District is in compliance with the requirements of AB 52 and Public Resources Code §21080.3.1 which implements AB 52.

VI.7. Energy Conservation Impacts

Comment: The DEIR failed to evaluate Energy Conservation impacts following Appendix F. The DEIR needs to describe and evaluate the energy consuming equipment and processes that will be used during construction and operation.

Shell

Response: Appendix G of the CEQA Guidelines states that "Potentially significant energy implications of a project shall be considered in an EIR to the extent relevant and applicable to the project." The EIR evaluated the potential increase in electricity, the equipment that would require the increase in electricity, and the related GHG emissions in Section 3.3.4.2.4 of the EIR. Table 3.3-15 of the Draft EIR provided the estimated increase in electricity associated with WGSs and SCRs and estimated the potential increase in electricity demand. As stated in Chapter 3.3.5, measures to mitigate operational GHG emission impacts typically rely on energy efficiency measures. "Improving energy efficiency is equipment- and operation-specific, so each affected facility operator would have to perform a facility-wide evaluation to determine appropriate energy efficiency measures. Such an analysis is outside the scope of the environmental analysis for the proposed project." Therefore, to the extent feasible, energy impacts were evaluated in the EIR. The programs designed to reduce GHG emissions in California are aimed at energy efficiency as well as requiring the use of renewable energy sources. As discussed in the Regulatory Setting (see page 3.3-13), SB 32 and 350 will reduce GHG emissions by 40 percent below 1990 levels by 2030 to ensure California meets its target of reducing GHG emissions to 80 percent of 1990 levels by 2050 and required CARB to update the Climate Change Scoping Plan. The Scoping Plan requires energy efficiency in all sectors in California.

VI.8. Agriculture and Forestry

Comment: The Agriculture and Forestry section should evaluate if distribution infrastructure or other infrastructure and components within public and private right-of-way potentially be included under the purview of either proposed ruling.

Shell

Response: Proposed Rule 12-16 would establish emission caps on the refineries and related facilities. The rule is not expected to require distribution infrastructure in public right-of-ways. As discussed throughout the IS as well as the EIR, construction activities are expected to be confined to the boundaries of the existing refinery facilities.

VI.9. Biological Analysis

Comment: The biological analysis includes a number of incomplete analyses requiring substantial evidence to justify elimination and should also include regulatory review. This analysis is very conceptual without providing any specific information that relates to locations where possible issues affecting coastal / bay or other wetlands.

Shell

Response: As discussed in the IS, refinery facilities have been graded and developed and biological resources apart from landscape species have been removed in the operating portions of the refinery. To be effective, air pollution control equipment is sited close to the equipment that it is trying to control. Therefore, any control equipment that may be required under Rule 12-16 is expected to be located near the operating portions of the refineries. While wetland and other biological resources may be located within the confines of existing refineries, they are generally not located near the operating portions of the refineries. Please note that the NOP/IS and DEIR were sent to the State Clearinghouse so that all appropriate state agencies had access to information concerning the proposed rule. However, no public agency provided comments on the NOP/IS or DEIR. As suggested by the commenter, when and if specific emission reduction projects are implemented by refineries, they would be subject to further CEQA review. Further, as also suggested by the commenter, there are a number of existing rules and regulations that apply to the protection of biological resources, including the migratory bird act. Compliance with these existing rules and regulations is required regardless of whether Rule 12-16 is approved. For example, compliance with the migratory bird act is required should trees be removed. However, as stated previously, new control equipment is expected to be near the operating portions of the refinery where trees and other vegetation have been removed to minimize fire hazards. Therefore, mitigation measures that reiterate the requirements of existing laws are not required.

VI.10. Cultural Analysis

Comment: The cultural analysis is incomplete. Rule 11-18 discussion only addresses archaeology and does not consider history structures, while the Rule 12-16 analysis addresses historic structures and not archaeology. Paleontology and human remains are not discussed.

Shell

Response: As discussed in the IS (see pages 2-23 of Appendix A of the DEIR), refinery facilities have been graded and developed. To be effective, air pollution control equipment is sited close to the equipment that it is trying to control. Therefore, any control equipment that may be required under Rule 12-16 is expected to be located near the operating portions of the refineries where cultural resources, including archaeological, paleontological, historical, tribal resources, and human remains would not be expected to be located.

VI.11. Transportation Analysis

Comment: The transportation analysis is incomplete. Because refineries and likely other TAC emitting facilities, utilize marine vessels and railcars, equipment, etc., marine transportation and railcars should have been components of the transportation analysis.

Shell

Response: Although marine vessels and railcars are used to transport feedstock and products, no changes to marine or rail transportation are expected due to implementation of Rule 12-16, so their impacts do not need to be evaluated. As discussed throughout the DEIR, installation of new air pollution control equipment could result in an increase in truck transport, but materials to support the operation of air pollution control equipment (e.g., ammonia and caustic) would not be expected to be delivered by vessel.

VI.12. Odor Impacts

Comment: The DEIR did not present significance determination associated with the odor impacts in the DEIR. The analysis should require that odors be minimized and piles of organic matter in soil be covered to reduce odors.

Shell

Response: The DEIR did not include an odor analysis because it was concluded in the Initial Study for the proposed project, that Rule 12-16 would not generate significant adverse odor impacts. The rule is not expected to result in an increase in odorous emissions at the refineries. As noted in the Initial Study, hydrogen sulfide (H_2S), which is the primary odorous compound emitted from the refineries, or other odorous sulfur-containing compounds are not expected to increase as a result of adopting proposed Rule 12-16. In addition, all facilities affected by Rule 12-16 are also subject to Regulation 7, which places general limitations on odorous substances and specific emission limitations on certain odorous compounds. Regulation 7 states further that a person shall not discharge any odorous substance which causes the ambient air at or beyond the property line of such person to be odorous and to remain odorous after dilution with four parts of odor-free air. Therefore, odors such as those described in the comment would either be minimal or eliminated through compliance with Regulation 7.

VI.13. Regional Growth

Comment: The DEIR failed to account for the impact of projected regional growth which may require additional need for goods and materials and how this would influence the impacts of the proposed rules, including increased demand for transportation fuel that may require local refineries to increase capacity and/or these be supplied by facilities outside of the region.

Shell

Response: As detailed in previous responses, the caps are set at levels consistent with the full-capacity operation of the refineries. Furthermore, projections of transportation fuel demand from ARB and the EIA show decreasing demand for these products despite population and economic growth due to increasing efficiency and transition away from petroleum-based fuels.

VI.14. General Information

Comment: The General Information section does not provide General Plan Designations or Zoning as required. These Plans need to be further researched and discussed.

Shell

Response: The information regarding the general plan and zoning designation of each of the five refineries are provided below. All of the General Plan and land use plans for Richmond, Martinez, Benicia and Rodeo (Contra Costa County) allow for and encourage the continued use of industrial areas within their respective communities. Some of the General Plans encourage the modernization of existing industrial areas, including the refineries. A summary of the land use policies that apply to industrial areas is summarized for each community that the five Bay Area refineries are located.

1. Richmond General Plan 2030 includes the following land use policies regarding industrial areas (Richmond, 2015[1]).

    - Action LU3.H Industrial Lands Retention and Consolidation Ensure that industrial uses are consolidated around rail and port facilities and work with existing industrial operators, economists and commercial brokers to remain informed about the future demand for industrial land.
    - Action LU3.I Industrial Modernization Support heavy industry's on-going efforts to modernize and upgrade their plants to reduce energy use, increase efficiency and reduce emissions.

2. City of Martinez General Plan includes the following land use policies regarding industrial areas (Martinez, 2015[2]).

    - 21.51 Expansion of the petroleum refining and related industries must proceed in an orderly fashion and be consistent with protection of the community's air, water, scenic and fiscal resources.
    - 30.351 Adequate land for industrial growth and development should be provided. It is the policy of the City to encourage and assist existing industry to relocate away from the southern perimeter of the waterfront.
    - 30.352 The City should consider further annexation to the east of the current Martinez City Limits to provide space for expansion of industry.
    - 30.353 Industrial expansion accompanied by adverse environmental impact will not be permitted.
    - 30.354 Acceptability of any industry shall be based upon its demonstrated ability to conform to performance standards set by the City.
    - 30.355 Architecture of some merit and landscaping of building sites and parking areas should be required; according to design and landscaping criteria for industrial sites.

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[1] City of Richmond (Richmond), 2015. Land Use and Urban Design, Richmond General Plan 2030. http://www.ci.richmond.ca.us/DocumentCenter/Home/View/8809.

[2] City of Martinez (Martinez), 2015. Martinez General Plan. City of Martinez. http://www.cityofmartinez.org/civicax/filebank/blobdload.aspx?BlobID=7569

3. City of Benicia General Plan includes the following land use policies regarding industrial areas (Benicia, 2015[3]).

- **POLICY 2.6.1:** Preserve industrial land for industrial purposes and certain compatible “service commercial” and ancillary on-site retail uses.
- “Compatible,” as defined in the California General Plan Glossary, means “capable of existing together without conflict or detrimental effects.” Compatibility will often be decided on a case-by-case basis by the Planning Commission and City Council.
- **POLICY 2.6.2:** Other land uses should not adversely affect existing industrial and commercial land uses.
- Program 2.6.A: Where General Plan amendments propose to convert industrial land to non-industrial or non-commercial uses, require the preparation of a fiscal and economic impact analysis to ensure that the conversion does not adversely affect the city’s longterm economic development, or the economic vitality of existing industrial/commercial uses.
- Program 2.6.B: Develop criteria for evaluating whether a proposed non-industrial/non-commercial use would impact the viability of existing industrial/commercial uses. Use the criteria to evaluate non-industrial and non-commercial projects proposed in the Industrial Park.
- **POLICY 2.6.3:** Facilitate continued development of the Industrial Park. Especially encourage general industrial uses to locate in the basin northeast of Downtown (around Industrial Way between East Second and the freeway).
- Program 2.6.C: For lands designated limited industrial, reduce the length of time and number of steps required for development proposals to proceed, consistent with CEQA, community development policies and ordinances, and the design review process for general industrial lands.
- **POLICY 2.6.4:** Link any expansion of Industrial land use to the provision of infrastructure and public services that are to be developed and in place prior to the expansion.
- Program 2.6.D: Continue to update the overall capital improvements program and infrastructure financing plan for the Industrial Park and other major industrial areas.
- Program 2.6.E: Develop Industrial Park infrastructure and public services standards, as approved by the City Council.
- **POLICY 2.6.5:** Establish and maintain a land buffer between industrial/commercial uses and existing and future residential uses for reasons of health, safety, and quality of life.
- Program 2.6.F: Use topography, landscaping, and distance as a buffer between Industrial Park uses and residential uses.

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[3] City of Benicia (Benicia), 2015. From 1847 Benicia General Plan Into the 21st Century. City of Benicia. Adopted: June 15, 1999. http://www.ci.benicia.ca.us/index.asp?Type=B_BASIC&SEC={4961C62F-22A5-4BB7-B402-D050A5856B00}&DE={8874E99E-FF86-45FF-8F9D-FAC81A3022A5}

- A buffer is "adequate" to the extent that it physically and psychologically separates uses or properties so as to shield, reduce, or block one set of properties from noise, light, or other nuisances generated on or by the other set of properties. Buffers will be determined on a case by case basis.

4. Rodeo: The Contra Costa General Plan Land Use Element identifies the following land use policies (CCC, 2015).

    - 3.163. A buffer of agricultural lands around the eastern Union Oil (currently Phillips 66) property is created in this plan to separate the viewpoint residential area from future industrial development on the property. These open space lands should remain undeveloped.

Based on a review of the applicable land use plans, the construction of equipment within the confines of existing refineries is not expected to conflict with any applicable land use plan, policy or regulation of an agency with jurisdiction over the project. The jurisdictions with land use approval recognize and support the continued use of industrial facilities.

VI.15. Mandatory Findings of Significance

Comment: The Mandatory Findings of Significance is inadequate and notably lacks substantial justification for impact findings; the findings under this section require reconsideration. The justification for there being no potential to degrade the quality of the environment is unsubstantiated and non-objective.

Shell

Response: The intent of this comment is not clear. The Initial Study contains a Mandatory Findings of Significance section. As discussed in that section of the Initial Study the potential secondary adverse air quality impacts, including cumulative impacts would be addressed in the EIR. As discussed throughout the Initial Study, the potentially significant impacts associated with implementation of Rule 12-16 would be discussed in the Draft EIR. Please see the Draft EIR for the evaluation and analysis of the potentially significant environmental impacts and the appropriate significance conclusions (primarily in Chapter 3 of the EIR).

VI.16. Secondary Impacts

Comment: The DEIR limited its analysis of secondary impacts only to installing air pollution control equipment to comply with risk reduction plan requirements of Rule 11-18 and emissions limits of Rule 12-16.

Shell

Response: In order to comply with Rule 12-16 and increase fuel production while maintaining compliance with refinery caps, it is expected that the refineries would install additional air pollution control equipment and more energy efficient equipment to limit refinery emissions. Other impacts such as an increase in the demand for fuels and potential secondary impacts are considered speculative and their related impacts are also considered speculative. CEQA Guidelines Section 15145 states that if a particular impact is too speculative for evaluation, the lead agency should note its conclusion and terminate discussion of the impact.

VII. Documentation/Clarifications Needed or Typos

Comment: Revise Appendix A of the DEIR to include the “Health Experts’ December 2016 comment on the DEIR Scope,” “CBE December 2016 Technical Report on the DEIR Scope,” and “December 2016 Legal Comment of 350 Bay Area, CBD, CBE, NRDC, and Sierra Club on the DEIR Scope.”

Health Professionals, R. Lin, et al.

Response: The appendix will be revise to include the “Health Experts’ December 2016 comments and “December 2016 Legal Comment of 350 Bay Area, CBD, CBE, NRDC, and Sierra Club on the DEIR Scope.”

Comment: The IS references were inadequate. The fact that only three references were used in the development of the IS further demonstrates the lack of intent to comply with the spirit of CEQA.

Shell

Response: It is the opinion of the commenter that a sufficient number of references were not used in the preparation of the IS. CEQA does not mandate the use of a specific number of references for preparation of an IS or EIR.

Comment: The list of preparers and agencies consulted is deficient. This section of the DEIR provides a list of names, but does not provide any affiliation or interest rationale to offer insight into the consultation value to the process. The list must indicate the name, affiliation, and a very brief explanation of each individual’s role in preparation of the EIR.

Shell

Response: CEQA Guidelines Sections15129 indicates that the EIR shall identify all federal, state or local agencies, other organizations, and private individuals consulted in preparing the draft EIR, and the persons, firm, or agency preparing the draft EIR. That information was provided in Section 5.3, page 5-7 of the DEIR. CEQA Guidelines Sections15129 does not require the name, affiliation or “interest rationale: to be included.

Comment: The DEIR does not provide reference for its assertion of the refinery average utilization rates.

Shell

Response: The 80- 87 percent utilization rate is provided in the Staff Report for Rules 11-18 and 12-16. A reference for these data will be added to the Final EIR for clarification).

Comment: Most resource sections only include a general boilerplate statement of the regulatory framework of each given resource.

Shell

Response: The regulatory setting portion of the DEIR provides a summary of regulations that are applicable to the protection of each of the environmental resources evaluated in the DEIR. Existing regulations generally serve to protect the resource and are generally requirements for compliance for new projects or modifications. The applicable rules are identified by numbers, e.g., Air District Regulation 8, Rule 18: Equipment Leaks or federal GHG Reporting Program (40 CFR Part 98 which can be further reviewed, if the reader is interested.

Comment: The DEIR Table 3.2-1 is missing some AAQS; it does not show the state AAQS of sulfates, hydrogen sulfide and vinyl chloride.

Shell

Response: The ambient air quality standard for sulfates was included in Table 3.2-1. Hydrogen sulfide and vinyl chloride have been added to Table 3.2-1, these pollutants are generally regulated on a site-specific basis as opposed to a regional basis.

Comment: The construction emission significance criteria are provided with no citation of substantial evidence.

Shell

Response: Contrary to the assertion in this comment, the construction significance thresholds are based on substantial evidence and included review by the public prior to adoption by the Air District's Governing Board. For additional information see BAAQMD, 2010.

Comment: The basis for the water demand significance threshold is not explained.

Shell

Response: CEQA Guidelines Section 15155 – City or County Consultation With Water Agencies, defines a "water demand" project in several ways. While the criteria for defining water demand are not significance thresholds per se, the criteria can provide some insight as to how city or county lead agencies evaluate water demand impacts. CEQA Guidelines §15155 (a)(1)(C) defines a water-demand project as: "A commercial office building employing more than 1,000 persons or having more than 250,000 square feet of floor space." To estimate what this means in terms of water demand per person relative to the square footage (sf) of the floor area of the plant, commercial water usage rates[4] and

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[4] California Commercial End-Use Survey, Consultant Report, Table 8-1, p 150. Prepared For: California

average employment levels[5] (i.e. the number of employees per square foot) can be applied as follows:

$$\frac{\text{(123 GAL WATER)}}{\text{(YEAR) (SF OF BUILDING)}} \text{ X } \frac{\text{(1,000 SF OF BUILDING)}}{\text{(1.8 EMPLOYEES)}} \text{ X } \frac{\text{(1 YEAR)}}{\text{(260 DAYS)}} \text{ X } \text{(1,000 EMPLOYEES)} = \text{262,820 GAL/DAY}$$

This water demand estimate can then be applied to industrial sources because CEQA Guidelines §15155 (a)(1)(E) uses the same 1,000 employee level to defines a water-demand project as: “An industrial, manufacturing, or processing plant or industrial park planned to house more than 1,000 persons, occupying more than 40 acre of land, or having more than 650,000 square feet of floor area.”

Finally, the typographical error noted on page 3.5-20 will be corrected in the Final EIR.

Comment: The evaluation of impacts to water quality is incomplete. The analysis should address the potential impacts from instances when wastewater from a wet scrubber is not treated and recycled to minimize water demand.

Shell

Response: As noted in the DEIR, not all of the wastewater generated by air pollution control equipment would be discharged as wastewater. Some portion of the wastewater would likely be emitted as steam or is treated and recycled. Depending on the volume of potential wastewater discharged, if it is not within the percent variation allowed by the local sanitation districts, affected refinery operators may need to apply for revisions to their Industrial Wastewater Discharge Permit. Regardless of the facility, wastewater discharges from an industrial facility would be required to be discharged in compliance with the applicable wastewater discharge permits and, therefore, impacts would be less than significant. For additional information, refer to DEIR Section 3.5.4.2.

Comment: Very few citations are provided for the data provided and when provided, not all references listed are used and not all references used are refenced accurately or at all. In addition, there are numerous examples where available information was not obtained for the purpose of completeness.

Shell

Response: The commenter does not provide examples of data that they believe have not been properly referenced. Please note that the citation to “BAAQMD, 2017” is to the final EIR for the Air Plan.

Energy Commission, Prepared by: Itron, Inc. March 2006. http://www.energy.ca.gov/2006publications/CEC-400-2006-005/CEC-400-2006-005.pdf

[5] Urban Land Use Institute Data, Wausau West Industrial Park Expansion, Development Impact Analysis, Average Employment Levels, p.4, Prepared by Vierbicher Associates, January 5, 2001.

Comment: Table 3.3-15 included electricity use for wet gas scrubbers and SCRs while the title only indicates that wet gas scrubbers are included.

Shell

Response: The title on Table 3.3-15 (now Table 3.3-13 in the final EIR) has been modified as suggested.

Comment: The text citation of source of the 2015 GHG emissions inventory does not match Table 3.3-3.

Shell

Response: The correct reference is BAAQMD 2017 and it has been corrected in the Final EIR.

Comment: The format of this section is not consistent with the other assessment sections.

Shell

Response: As suggested in this comment Chapter 3.5 has been revised in the Final EIR and made consistent with other sections of the EIR.

Comment: Note that neither the alternatives discussion or Tables 4-2a or 4-2b include the alternative to adopt Rules 12-16 and 11-18 together, yet there is discussion of this alternative in the document.

WSPA

Response: In Section 2.1, the DEIR discusses the potential for adoption of either, both, or neither by the Board of Directors. While the alternatives analysis does not contain discussion for the combination of both Rules 11-18 and 12-16, the cumulative impacts analysis addresses the cumulative impacts of the adoption of both rules along with the impacts of the Refinery Strategy as was discussed in the EIR for the 2017 Clean Air Plan.

Comment: Emission intensity caps (Rule 13-1) and mass emission caps (Rule 12-16) are complementary measures and their combination could protect health better than Rule 12-16 alone. This alternative is not considered in the draft EIR although Rule 13-1 is discussed in combination with Rule 11-18. CEQA requires an alternative to accomplish the main objectives of the project at hand, yet Rules 13-1 and 11-18 do not provide health protection equivalent to 12-16. Rule 11-18 targets various toxic air contaminants but not greenhouse gases and particulate matter and is fundamentally different in terms of health protection strategy and outcome. Rule 13-1, as currently drafted, omits direct control of PM2.5 and could allow facility-wide refinery emissions to increase; it is does not provide protections comparable to Rule 12-16. Regardless, it is premature to consider Rule 13-1 in the Rule 12-16 EIR.

CBE, Health Professionals

Comment: Rule 12-16 could prevent a refinery combustion emissions increment of as much as 40–100 percent regionally over 40 years.

CBE

Response: CEQA Guidelines, Section 15126.6(a) states: “An EIR shall describe a range of reasonable alternatives to the project… which would feasibly attain most of the basic objectives of the project but would avoid or substantially lessen any of the significant effects of the project, and evaluate the comparative merits of the alternatives.” Accordingly, a subset of Rule 12-16 could be considered as an alternative if it met the criteria listed in Section 15126.6(a); however, the superset of a combination of both Rules 12-16 and 13-1 could not possibly meet these criteria because the resulting significant effects could be no less than either rule alone.

Comment: Tables 4-2a on page 4-18 and 4-2b on page 4-19 have a column identified as the “proposed project” but no clear “proposed project” has been identified.

WSPA

Response: Indeed, the DEIR addresses two proposed projects: draft Rule 11-18 and proposed Rule 12-16. As the titles of the tables indicate, “proposed project” in Table 4-2a refers to Rule 11-18 and in Table 4-2b, Rule 12-16.

Comment: The Air District should use more recent data for this EIR than the 2011 emission inventory. The Air District needs to state why it is using 2011 annual emissions data for a 2014 Inventory Summary Report in a 2017 DEIR.

WSPA

Response: There are limited emissions data available to that would serve to establish emissions limits. The use of 2011 emissions data is appropriate for establishing recent trends in refinery emissions and thereby setting emissions limits.

Comment: The Air District follows Table 3.2-4 with a discussion of how the air has improved and cites percentages. However, the source of that information is not provided and needs to be provided. The public and the decision-maker should be provided with the most current data to properly assess the impacts and mitigation.

WSPA

Response: The commenter is mistaken. All data presented in the discussions following Table 3.2-4 up to Table 3.2-5 are well cited. These citations include:

- BAAQMD, 2015. Bay Area Emission Inventory Summary Report: Greenhouse Gases, January 2015.
- BAAQMD, 2016. Toxic Air Contaminant Air Monitoring Data for 2014. Provide by BAAQMD.
- BAAQMD, 2017. DEIR for the Draft 2017 Clean Air Plan: Spare the Air, Cool the Climate: A Blueprint for Clean Air and Climate Protection in the Bay Area. Accessed March, 2017. http://www.baaqmd.gov/~/media/files/planning-and-research/plans/2017-clean-airplan/2017plandrafteirpdf-pdf.pdf?la=en

Comment: On Page 3.2-31, Section 3.2.4.1.2, the DEIR states: "It is assumed that the proposed project has the potential to result in the construction of up to three to five WGS units under Rule 11-18 or three to five units under Rule 12-16." What is the basis for this assumption? Since Rule 11-18 would apply to many industries and facilities, why is the assumption the same for Rule 11-18 as for Rule 12-16, which only applies to five refineries and three ancillary facilities?

WSPA

Response: Currently, only one facility in the Bay Area operates a wet gas scrubber: Valero Refinery in Benicia. However, it is possible that up to four facilities could potentially utilize a WGS to control SOx, PM (addressed by Rule 12-16) and/or TAC emissions (addressed by Rule 11-18); these facilities are the Chevron Refinery in Richmond, the Shell Refinery in Martinez, the Tesoro Refinery in Martinez, and Lehigh Cement Plant in Cupertino (the largest single source of SOx emissions in the Bay Area)—which supports the range of three to five expressed in the DEIR.

Comment: On Page 4-7 Section 4.3.2, Alternative 2.2., the DEIR states: "…This alternative would consist of a combination of the environmental benefits and impacts of adopting and implementing proposed Rule 12-16 and draft Rule 13-1." The Air District should clarify whether Rule 12-16 is part of this alternative as stated in the first sentence or if this is a typographical error. If 12-16 is part of this alternative, the Air District should explain the impacts and the analysis in the alternative.

WSPA

Response: The inclusion of "12-16" in the reference sentence is in error and should refer to "11-18" as does the title of that subsection. This will be corrected in the Final EIR.

Comment: The second and third paragraphs in Section 3.2.1.2.4 of the "Environmental Setting" include two paragraphs of statements that are uncited and imply causality without any quantitative information on whether those correlations are causal.

WSPA

Response: Staff agrees and the final EIR will provide citations for the two paragraphs mentioned in the comment.

Comment: Section 3.3.3 of the DEIR includes a paragraph that identifies a project level GHG threshold for stationary source projects of 10,000 metric tonnes of CO_2e, citing the District's 2010 CEQA Air Quality Guidelines. Those Guidelines identified a threshold of 10,000 metric tonnes of CO_2e per year of operational emissions. As identified on the District's CEQA webpage, the District was ordered to "*set aside the Thresholds and is no longer recommending that these Thresholds be used as a general measure of project's significant air quality impacts.*"

WSPA

Response: In establishing a GHG significance threshold for programs such as the 2017 Clean Air Plan, a no net increase GHG significance threshold is used and is considered the most stringent threshold among available thresholds so no further justification is necessary. The 2017 Clean Air Plan provides GHG emission reduction targets based on emissions from all sources within the Air District's jurisdiction. A no net increase significance threshold allows Air District staff to evaluate whether or not the Plan is achieving its GHG emission reduction goals and whether or not additional control measures or strategies are necessary to achieve GHG emission reduction goals.

The no net emission increase significance threshold does not apply to individual stationary source projects, instead the Air District uses a GHG significance threshold of 10,000 MT CO_2e per year for stationary source projects. Contrary to the assertion in this comment, this stationary source significance threshold is based on substantial evidence and included review by the public prior to adoption by the Air District's Governing Board. For additional information see BAAQMD, 2010.

Comment: Section 4.3.1 states that there are no facility-wide emissions limits on refineries; that is incorrect. There are facility-wide emissions limits, either spelled out explicitly in permits or as a result of equipment-specific emissions limits and/or equipment capacities ("potential to emit").

WSPA

Response: The commenter is incorrect. The DEIR does not state that there are no facility-wide emissions limits on refineries; it states: "Under the No Project Alternative (12-16), the proposed rule would not be adopted and, thus, facility-wide emissions limits on GHGs, PM (PM_{10} and $PM_{2.5}$), NOx, and SO_2 would not be established." The facility-wide emissions limits in that quoted sentence is referring to those limits contained in proposed Rule 12-16. This is not the same as stating there are not facility-wide emissions limits.

Comment: On Page 3.5-23, Section 3.5.5.2., the DEIR states: "Therefore, the proposed project will remain significant after mitigation for water demand." What does "proposed project" refer to in this sentence? Is the proposed project Rule 12-16, 11-18 or both? The District needs to identify the actual project. The Air District must weigh and analyze the expected improvement by adopting the Rules against the significant impact on water demand even after mitigation.

WSPA

Response: The commenter is correct in that the section is not clear as to what the "proposed project" is. This will be clarified in the final EIR.

Comment: The District should use market researchers, analysts' forecast, and California Energy Commission resources to estimate gasoline demand rather than simply stating that demand is impossible to predict. The effects of AB-32 on refineries should also be discussed.

D. Kubeck, M. Johnson, S. Ardito, S. Lee

Response: Any forecast of gasoline demand would be considered speculative and, therefore, inappropriate for consideration under CEQA. CEQA Guidelines Section 15126.6(f)(3) states that “[a]n EIR need not consider an alternative whose effect cannot be reasonably ascertained and whose implementation is remote and speculative.” The potential effect of Rule on gasoline prices is discussed is the Staff Report and the socioeconomic analysis, which is appropriate.

Comment: The Air District staff's recent finding that "emissions leakage would not occur as a result of Rule 12-16" (CAP DEIR at 3.3-24) discredits arguments against your authority to implement this rule immediately.

T. Finley

Response: While leakage may not occur as a result of the implementation of Rule 12-16, there are other issues with the requirements of the rule that may conflict with the Air District’s authority. Federal Clean Air Act (CAA) and the California Health and Safety Code (H&SC) require the Air District to develop permitting programs that allow for criteria pollutant emissions to increase at a facility as long as those emissions are offset by an equal or greater amount of reductions of the same pollutant from a location within the region (CAA Sections 173(a) and 173(c)(1) and H&SC Sections 40918(a) and 40709(a)). The Air District has such a permitting program embodied in Regulation 2: Permits, Rule 2: New Source Review (Rule 2-2). This rule applies equally to all facilities in the Bay Area. Although state and local agencies may adopt more stringent rules than required by federal and state law, there is a significant argument that a fixed numeric cap for criteria pollutants conflicts with these federal and state provisions that allow facilities to increase emissions if certain conditions are met.

VII.1. Technical issues

Comment: The emission cap of 7 percent allowance is unsubstantiated. Is there information to support that 7 percent is appropriate to capture year-to-year variation? The DEIR did not adequately address the impact of the 7 percent allowance on future socioeconomic impacts, impacts from decrease operational flexibility and impacts from leakage.

Shell

Response: The Air District conducted an analysis on the year-to-year variation of refinery GHG emissions and found that the average facility GHG emissions variability was slightly larger than 6 percent during recent years. Air District staff used ARB’s GHG mandatory reporting data for the refineries and associated facilities subject to proposed Rule 12-16, reported for calendar years 2011 – 2015. This time period is consistent with the emissions baseline for proposed Rule 12-16 and also represents the calendar years for which ARB’s GHG mandatory reporting data was reported using a consistent methodology.

Comment: The DEIR mentions that emission limits under Rule 12-16 would change if the method of monitoring or estimating emissions changes, but fails to describe the mechanism.

Shell

Response: Changes to methodology and subsequent changes to District rules would be subject to additional rule making and amendments to existing rules. Since the changes to monitoring or methodology are speculative at this time, their potential impacts are also speculative. CEQA Guidelines Section 15145 states that if a particular impact is too speculative for evaluation, the lead agency should note its conclusion and terminate discussion of the impact.

Comment: The DEIR is confusing as it fails to adequately define qualifying terms. The IS refers to *major* sources, *significant* contributions, *substantial* impacts, and the like. Without an objective definition of these terms, the analysis is unsubstantiated and further appears biased to justify the conclusion without a thoughtful analysis.

Shell

Response: Most of the terms outlined in this comment are used in the general English terminology. Significant impacts have been defined as impacts that exceed significance thresholds.

Comment: The construction estimates for installing pollution control devices is not realistic. Experience shows that the concept, funding, design, permitting and construction could take several years and are very expensive units to purchase and operate.

Shell

Response: The comment asserts that the construction estimates for installing a new wet gas scrubber are not realistic, but does not provide any data or other information for a more realistic schedule. The comment only notes that installing a wet gas scrubber from concept to completion may take years, which provides less detail on the construction schedule than is included in the DEIR. Subsection 3.2.4.1.2 of the DEIR provides detailed information on installing a wet gas scrubber, including the construction schedule, which is based on a similar analysis of installing a wet gas scrubber on an FCCU in southern California (SCAQMD, 2007), types construction equipment, construction phases, numbers of construction workers per phase, etc.

Comment: The emission inventory used for setting emissions caps for Rule 12-16 is flawed. The Air District should perform an audit of the data in CEIDARS and compare to actual reported historical plant direct measured emissions (e.g., CEMS) and cite the specific emissions factor calculated data.

Shell

Response: Affected facility emissions inventory data used by Air District staff are currently the most accurate data available. The impacted facilities were given an opportunity to review the data used to set the emission limits in Rule 12-16 and suggest changes and corrections in the data. All changes suggested by industry were made to the baseline data and the limits in the Rule reflect those changes

CEIDARS data provide a consistent framework of emissions inventory data used by all air pollution control districts in California in developing their individual air district attainment plans and, therefore, are appropriate for promulgating individual rules to implement the attainment plans.

Comment: The DEIR relies on mitigation measures to address NOx emissions that are deferred mitigation measures which are not allowed under CEQA. The NOx mitigation measures need to be revised and the DEIR recirculated.

Shell

Response: No specific projects are currently being proposed to install air pollution control equipment at this time; however, the installation of air pollution control equipment may be an impact of implementation of Rule 12-16. When applications are received for such equipment, mitigation measures will be imposed. Therefore, this is not delayed mitigation.

Comment: The GHG emissions significance threshold is not adequately based on substantial evidence. The DEIR suggests a “no net increase in emissions” thresholds as appropriate for overall air quality plans, but fails to provide proper justification that there are sufficient alternative measures in its overall air quality plan to ensure that any GHG emission increases as a result of the proposed rules would be adequately offset by other measures.

Shell

Response: In establishing a GHG significance threshold for programs such as the 2017 Clean Air Plan, a no net increase GHG significance threshold is used and is considered the most stringent threshold among available thresholds so no further justification is necessary. The 2017 Clean Air Plan provides GHG emission reduction targets based on emissions from all sources within the Air District’s jurisdiction. A no net increase significance threshold allows Air District staff to evaluate whether or not the Plan is achieving its GHG emission reduction goals and whether or not additional control measures or strategies are necessary to achieve GHG emission reduction goals.

The no net emission increase significance threshold does not apply to individual stationary source projects, instead the Air District uses a GHG significance threshold of 10,000 MT CO2e per year for stationary source projects. Contrary to the assertion in this comment, this stationary source significance threshold is based on substantial evidence and included review by the public prior to adoption by the Air District’s Governing Board. For additional information see BAAQMD, 2010.

Comment: The GHG emission inventory does not adequately include all indirect GHG emission which is consistent with the Air District's guidance on methodologies and included in GHG emissions inventory models used throughout the State.

Shell

Response: As indicated in Chapter 3.5 of the DEIR, the primary source of increased water demand and water requiring treatment is water used in a wet ESP. However, instead of clean water, it is likely that each affected refinery operator would utilize strip sour water or similar existing treated waste process water from elsewhere within each facility. Because existing sources of refinery wastewater, e.g., strip sour water or similar existing treated wastewater, could be used to operate a wet ESP, would produce minimal, if any GHG emissions. Similarly, wastewater from the wet ESP is collected and flows into a sump where it is typically treated and recycled to minimize water demand and wastewater generated from the equipment. Once recycled, wastewater generated by the wet ESP can also be returned to the wet ESP, which further reduces the total amount of water required for air pollution control, as well as the amount of wastewater discharged into the sewer system. Since the wastewater treatment system doesn't include a combustion source, no GHG emissions would be generated. Additional demand for electricity could occur for waste treatment, but the analysis of Rule 12-16 include indirect GHG impacts from increased electricity demand.

Comment: The District is basing its conclusion (Section 3.3.4.3) on historic data that the refineries have not exceeded the proposed Rules 12-16 emissions caps and, therefore, proposed 12-16 will not conflict with the existing State Cap and Trade program. At the outset, this assumption is faulty; the current emissions caps are based on historic levels of production, which may or may not reflect future demand.

WSPA

Response: The emissions limits are set at the maximum for annual emissions for each pollutant over a five-year period with an additional 7 percent to allow for operational variation. As stated in the Staff Report, on average, the emissions limits do not appear to inhibit refining capacity considering Bay Area refineries as a group, since typical annual average utilization is 80 – 87 percent, and the emissions limits appear to establish production capacity limits at approximately 89 – 93 percent utilization. When the supply for fuels is constrained, the impacts can be dramatic and felt statewide. In 2015, the ExxonMobil refinery in Torrance was offline for most of the year. In addition, imports of refined products increased ten-fold, resulting in additional GHG emissions from shipping. However, during this period, refineries in the Bay Area never exceeded any of the limits contained in Rule 12-16, which indicates that the limits are appropriately proposed.

Comment: Revise the Environmental Setting and Staff Report using CEC data for Bay Area refineries alone, instead of PADD 5 West Coast refinery data, and disclose that Bay Area refineries emitted below the Emission Caps while operating at maximum capacity; and make subsequent revisions to all sections of the DEIR and Staff Report that rely upon PADD 5 West Coast refinery data instead of Bay Area refinery data alone.

R. Lin, et al.

Response: Response to Comment: California Energy Commission crude throughput data for the Bay Area refineries is more difficult to access, and less transparent than EIA utilization data. EIA data is preferred because it is far easier to independently locate and review the data. In addition, the supply/demand balance of transportation fuels is a function of the performance of the entire Pacific Coast region's refinery operations (i.e. PADD 5) rather than just Bay Area refineries. However, the CEC data provides insights similar to those from the PADD 5 utilization data, as follows:

Year	Average Crude Throughput (%)
2006	92.2
2007	85.8
2008	91.7
2009	83.8
2010	83.7
2011	80.9
2012	84.2
2013	89.5
2014	96.2
2015	93.9

During peak transportation fuel demand period of 2006 – 2008, Bay Area refineries operated near 92 percent crude throughput during two of the three peak years. Crude throughput decreased during the recession, and is now increasing again with higher transportation fuel demands. The refineries operated at 94 – 96 percent crude throughput during 2014 – 2015, during the baseline period. Rule 12-16 provides emission limits (and production capacity) based on each refinery's highest annual emissions during the baseline period from 2011 – 2015 plus 7 percent increase to provide operating flexibility. The emission limits in Rule 12-16 are adequate to supply the Bay Area's current transportation fuel needs. Future needs are uncertain, as population growth is anticipated to be offset by increased use of mass transit, improved fuel economy, and more alternate fuel vehicles. Projections by the Energy Information Administration indicate total transportation fuel demand is expected to peak at approximately 7 percent above the baseline period in 2018, at a level 4 percent less than the peak fuel demand in 2007. If a Bay Area refinery has an unplanned outage, the remaining Bay Area refineries can increase production short-term to cover the loss of supply. A long-term unplanned outage such as the Exxon-Mobil Torrance Refinery outage from March 2015 – April 2016 is very uncommon, and therefore speculative.

VII.2. Air Monitoring

Comment: Regarding Table 3.2-2 – Bay Area Air Pollution Summary – 2015: there is lacking or missing emission information for cities with/near refineries (Richmond, Martinez, Benicia, Rodeo, Crockett). Why has this information been omitted? The following data is also missing: Bethal Island (no PM), Crockett (lacking information), Fairfield (lacking information and no PM data), Martinez (lacking information and no PM data), Patterson Pass (lacking information and no PM data), and San Ramon (lacking information and no PM data).

C. Potter, D. Kubeck, L. Rice, M. Johnson, N. Mendoza, S. Ardito, T. Yu

Response: The data included in Table 3.2-2 is not incomplete. Rather, it reflects the criteria pollutant data collected from 2013 to 2015 at regulatory fixed-monitoring sites operated by the Air District. The dashes in table 3.2-2 indicate that there is not a monitor for that pollutant at a given site. For example, the Richmond site operates SO_2, H_2S, and toxics monitors, and the table shows the SO_2 data, since H_2S and toxics are not criteria pollutants. Descriptions of what pollutants are measured at each Bay Area site can be found in the Air District's Air Monitoring Network Plans, submitted each year to EPA (see Table 2-2 of the 2015 Plan, http://www.baaqmd.gov/~/media/files/technical-services/2015_network_plan-pdf.pdf?la=en). The decision of what pollutants to measure at each site is determined by the monitoring objective at each site. The network design is reviewed frequently, and a report of these ongoing evaluations, along with proposed network changes needed to better reflect air quality within the Air District's jurisdiction, is submitted to EPA every five years. The next network assessment is due on July 1, 2020.

Comment: How does the Air District base a decision on incomplete information?
C. Potter, D. Kubeck, L. Rice, M. Johnson, N. Mendoza, S. Ardito, T. Yu

Response: The District uses the best monitoring, modeling, and emissions information available at a given time to develop and implement a strategy to reduce pollutants that have a negative health impacts for the public.

Comment: Since the exceedances of Ambient Air Quality Standards are not shown to be near the refineries, the District should present data supporting the need for this Rule. Why are fenceline monitoring data not included?

C. Potter, D. Kubeck, L. Rice, M. Johnson, N. Mendoza, S. Ardito, T. Yu

Response: While some emissions create impacts near the source, others are transported further away, and also can react with other emissions, contributing to high pollutant concentrations many miles from the source. Therefore, the ambient data from the entire Bay Area monitoring network, as well as emissions information from various sources, are all important for considering effective, achievable new emission reductions.

Comment: Why are fenceline monitoring data not included?

C. Potter, D. Kubeck, L. Rice, M. Johnson, N. Mendoza, S. Ardito, T. Yu

Response: Fenceline monitors were not included since the monitoring objectives of these sites are to identify unknown releases of pollutants at ground level, mostly from fugitive emission sources at the facility. The open path monitors used for many of the pollutants in the fenceline networks do not determine concentrations at a given location, and are not designed to measure the impact of the facility emissions on ambient air. We did add the $PM_{2.5}$ data from the Richmond community monitors (North Richmond, Atchison Village, and Point Richmond) to the $PM_{2.5}$ trends chart and the fixed-site Ground Level Monitors (GLMs) for SO_2 on the SO_2 trends chart. Updated charts may be found at the end of this Appendix. Neither of these data sources are considered regulatory, and the GLM monitors are inside the facility’s fencelines, and therefore, do not represent ambient air. However, the data, while more uncertain than the regulatory data, provide additional information of the distribution of these two pollutants near the refineries.

Comment: Considering the spatial distance between your monitoring stations and the variation in weather and wind currents, is it accurate to simply take an average of measured pollutants and use that model to calculate air quality metric compliance or is more sophisticated modeling and mapping required?

L. Rice

Response: The Air District follows the regulations promulgated by U.S. EPA and the California Air Resources Board that require certain monitoring and data calculation methodologies for showing compliance with the National Ambient Air Quality Standards (NAAQS) or California Ambient Air Quality Standards (CAAQS). Specific approved, accurate, and stable monitors, operated according to rigorous quality control and quality assurance requirements, and located according to regulations produce the data that is used to determine this compliance (see 40 CFR Parts 53 and 58). The metric that is calculated using this data to determine compliance with the NAAQS or CAAQS is called a design value. The calculation methodologies for design values for each pollutant are described by 40 CFR Part 50. Design values are typically determined for each site using three years of data, and the highest result is used to determine compliance of a given area. Using multiple years of data assures that the resulting design value includes more information about inter-annual variability of pollutant concentrations. The locations of the monitors used for this regulatory network are designed to capture population exposure and expected high concentrations, and can represent either near source or area-wide pollutant concentrations, depending on the pollutant. Since it is generally data from these networks that help determine the level of the standards, using the design value metric from these monitors is the appropriate way to determine compliance with those standards.

VIII. Unintended consequences/impacts/limitations

VIII.1. Operational Flexibility

Comment: The imposition of emission caps deprives refineries of operational flexibility needed to balance load, safety, capacity, product, and regulatory compliance. The impacts could include operational curtailment or shutdown, negative effects on the operability of pollution control equipment, limitations on future projects to modernize or make cleaner or low carbon fuels, and/or increased importation of fuels from outside the State or country.

Chevron, Phillips 66, Shell, WSPA

Response: While the emission limits contained in Rule 12-16 may pose some barriers to production, staff believes the limits are appropriately proposed and would account for unexpected decreases in capacity due to the shutdown of any one of California's refineries.

VIII.2. GHG Emissions

Comment: The DEIR includes no analysis of the extent to which the proposed regulations to reduce emissions from Bay Area refineries may result in increases in global GHG and the associated cumulative impacts, and needs to do so.

K. Liebe, L. Mintzer, Shell, WSPA

Response: Rule 12-16 provides emission limits (and production capacity) based on each refinery's highest annual emissions during the baseline period from 2011 – 2015 plus 7 percent increase to provide operating flexibility. PADD 5 refining averaged 82.6 percent utilization during the baseline period. 82.6 percent utilization + 7 percent for operational flexibility = a production range up to 89.6 percent annual average utilization. The highest annual average PADD 5 utilization has been 86.5 percent in 2015, and subsequently reduced to 85.8 percent utilization in 2016. 2017 year to date PADD 5 utilization has been 87.1 percent. The emission limits in Rule 12-16 are adequate to supply the Bay Area's current transportation fuel needs. Future needs are uncertain, as population growth is anticipated to be offset by increased use of mass transit, improved fuel economy, and more alternate fuel vehicles. Projections by the Energy Information Administration indicate total transportation fuel demand is expected to peak at approximately 7 percent above the baseline period in 2018, at a level 4 percent less than the peak fuel demand in 2007. If a Bay Area refinery has an unplanned outage, the remaining Bay Area refineries can increase production short-term to cover the loss of supply. A long-term unplanned outage such as the Exxon-Mobil Torrance Refinery outage from March 2015 – April 2016 is very uncommon, and therefore speculative.

IX. Legal Authority/How the regulation works with other regulations

Comment: The Air District needs to explain how Rule 12-16 will comply with (and not conflict with or violate) the federal Clean Air Act, California Air Quality Laws (including the State's Cap-and-Trade program and offset program, prohibition of mandating specific air pollution control equipment), BAAQMD regulations and programs, and existing permits and limits.

The Existing Regulatory Setting should also include any shortcomings of the existing regulations (specifically to protect communities near Bay Area refineries) that the proposed rules will address.

K. Liebe, R. Lin, et al., Shell, WSPA

Response: The Staff Report includes a discussion on regulatory background and legal authority. The Report describes Air District staff's concerns regarding possible conflicts between the proposed rule and federal or State air quality laws. While the Air District does not believe there is any requirement to describe "shortcomings" of existing regulations, the Staff Report represents staff's best effort to identify needs for improvement in air quality and how the proposed rule would address those needs.

X. Other Comments

Comment: The corresponding increase in fossil fuel exports will lead to an increase in exogenous air pollution in the Bay Area since a portion of the byproducts of combustion of fossil fuels exported from the Bay Area will return to us from Asia through transpacific atmospheric transport. This exogenous air pollution will directly threaten health and, also, impede progress toward the targets and goals of the 2017 Clean Air Plan. Exogenous / overseas sources of pollution are of increasing concern as they have been directly implicated in deaths in local populations and documented as a greater proportion of exposure than locally-sourced pollution in some settings. (Annenberg 2014, Christensen 2015, Zhang 2007, 2008, 2009).

Health Professionals

Response: This assertion is too speculative to be considered in this environmental assessment. Any incremental change in exogenous air pollution due to the implementation of Rule 12-16 would not be discernable and any estimation of such a change would more than likely prove insignificant.

Comment: The prior bundling of proposed Rule 12-15 and 12-16 in a DEIR in 2015 and later detachment from Rule 12-15 and rebundling with proposed Rule 11-18 in this DEIR is a stark pronouncement of its procedural inadequacy.

Shell

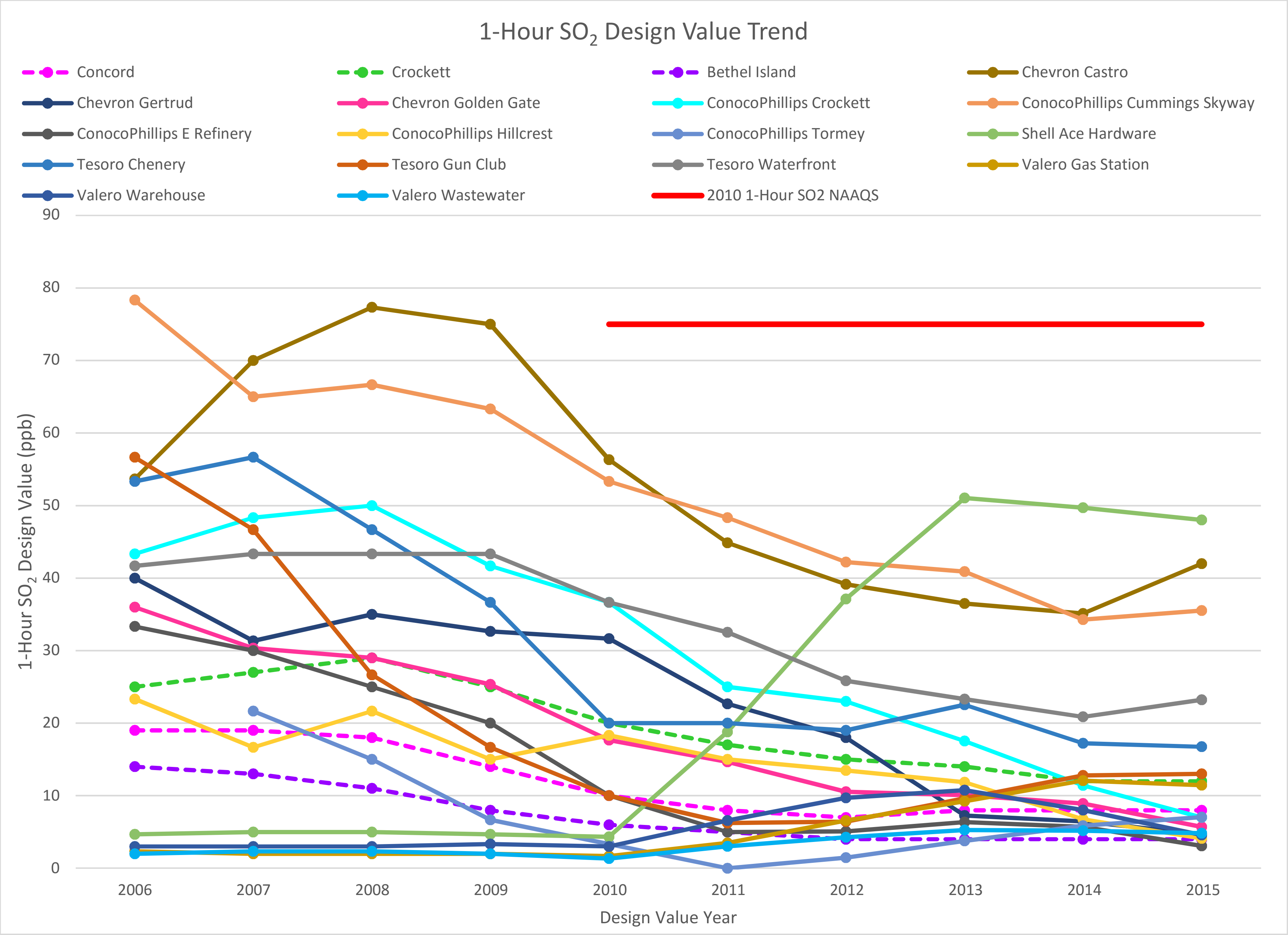
Response: The rules identified in the comment have evolved substantially due to information and comment from the public and regulated community. Rules have been proposed for adoption when they have been deemed ready, while others were delayed so that information and comment could be further evaluated and incorporated. For example, although Rules 12-15 and 12-16 were initially proposed at the same time, adoption of both was delayed. Rule 12-15 was subsequently deemed ready for adoption in April of 2016 while Rule 12-16 was undergoing a significant reworking.

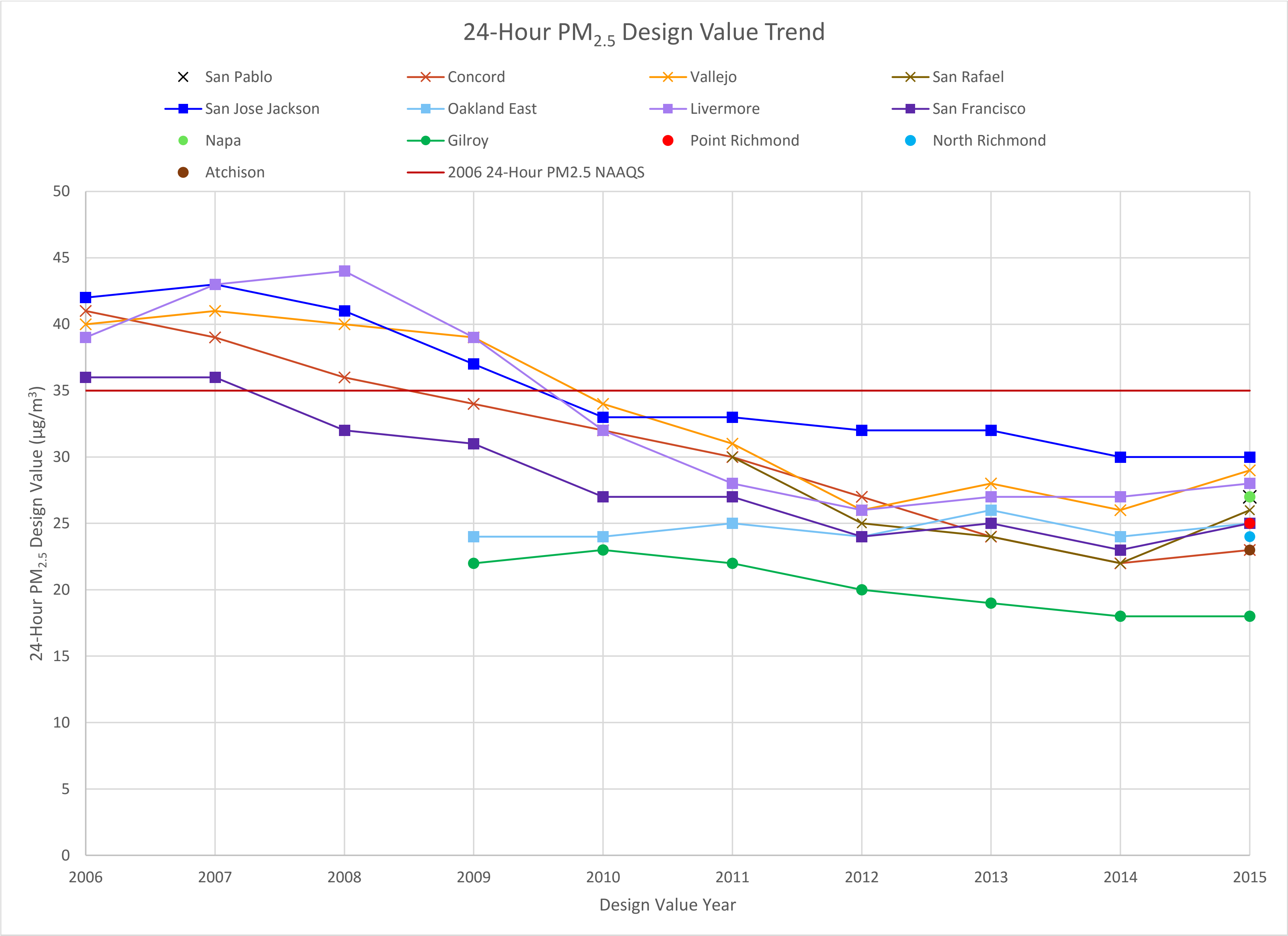
Rather than signifying a procedural irregularity, this sequence of events demonstrates a determination to proceed only after careful consideration of public comment.

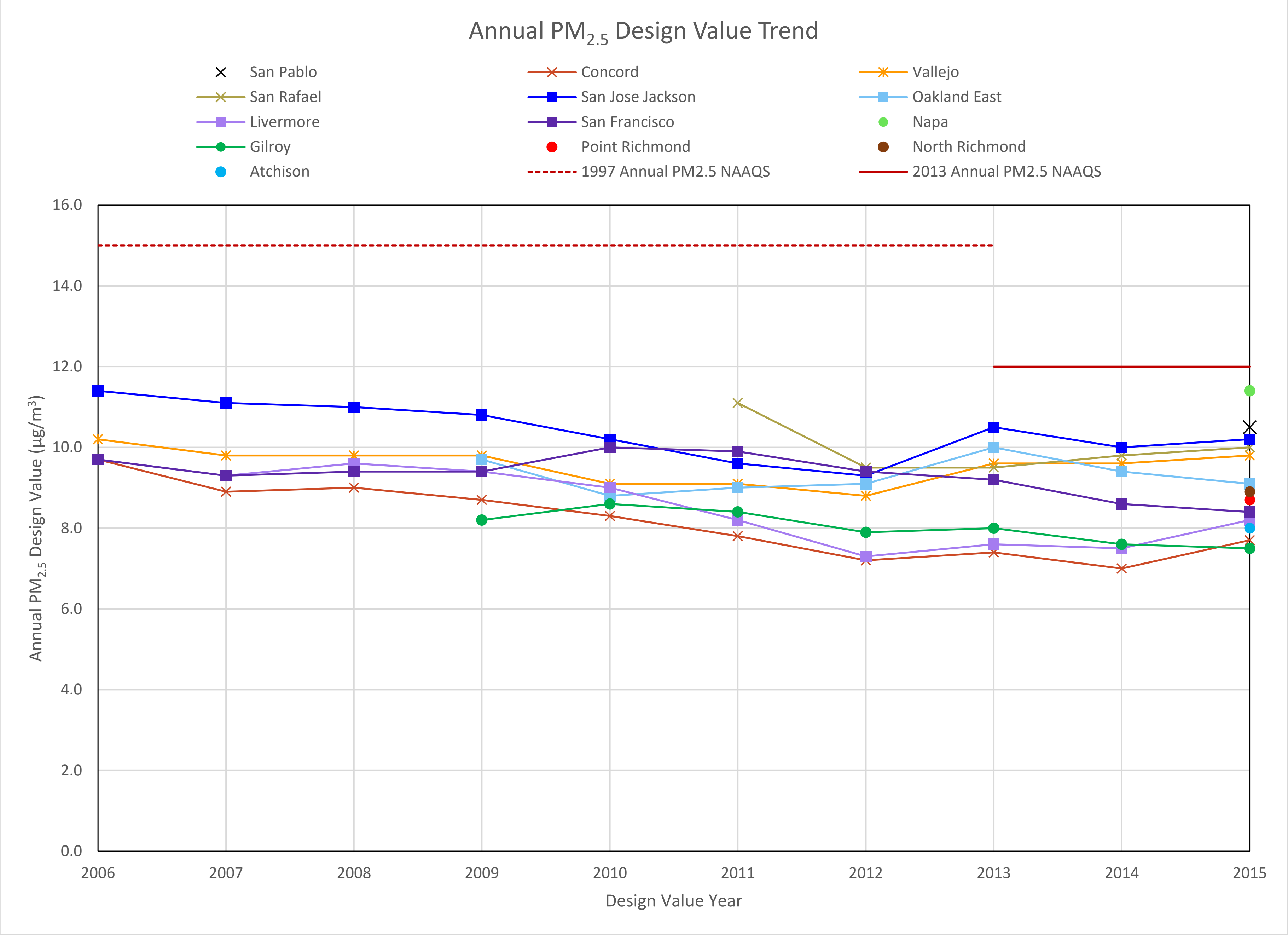
Commenters

C. Potter	Chris Potter, email: EIR Comments, May 3, 2017
CBE	Greg Karras, Communities for a Better Environment, letter: Draft Environmental Impact Report for Proposed Regulation 11, Rule 18 (Rule 11-18) and Proposed Regulation 12, Rule 16 (Rule 12-16), Bay Area Air Quality Management District, May 8, 2017
CCEEB	Bill Quinn, California Council for Environmental and Economic Balance, letter: Draft Environmental Impact Report for Proposed Rules 11-18 and 12-16, May 8, 2017
Chevron	Marc R. Bruner, PerkinsCoie, letter: Comments on Draft Environmental Impact Report (SCH #2016102043) For Proposed Air District Regulations 11-18 and 12-16, May 8, 2017
D. Kubeck	David Kubeck, email: Comments on Draft EIR: Regulation 11-18 & 12-16, May 7, 2017
Health Professionals	Heather Kuiper, DrPH MPH, et al, letter: Health Impacts and implications should be included in the No Project and alternative scenarios and the environmental and regulatory settings sections of the EIR for BAAQMD Rule 12-16, May 8, 2017
J. Riggs	James T. Riggs, email: Environmental Impact Report (EIR) for Rule 11-18 (HRAs and Toxic Emissions) and Rule 12-16 (Refinery GHG Caps), May 8, 2017
K. Liebe	Kurt Liebe, PE, email: BAAQMD Public Comment: Environmental Impact Report (EIR) for Rule 11-18 (HRAs and Toxic Emissions) and Rule 12-16 (Refinery GHG Caps), May 4, 2017
L. Mintzer	Laurie Mintzer, email: Rule 11-18 and 12-16 EIR Comments, May 8, 2017
L. Mejicanos	Lucas Mejicanos, email: Comments Proposed regulation 12, Rule 16: Petroleum Refining Facility-Wide Emissions Limits, May 8, 2017
L. Rice	Lynn Rice, email: Questions on EIR, May 4, 2017
M. Johnson	Matthew Johnson, email: EIR Comments, May 8, 2017
N. Mendoza	Nicole M. Mendoza, email: Comment Regarding EIR for proposed Rules 12-16 and 11-18, May 8, 2017
Phillips 66	Don Bristol, letter: Environmental Superintendent, Phillips 66 Company: Comments on BAAQMD's DEIR for Regulation 12, Rule 16 and Draft Regulation 11, Rule 18, May 8, 2017
R. Lin, et al	Roger Lin, Communities for a Better Environment, et al, letter: Comments on the Draft Environmental Impact Report for Regulation 11-18: Toxic Risk Reduction Rule (Rule 11-18) and Regulation 12-16: Petroleum Refining Facility-Wide Emissions Limits (Rule 12-16), May 8, 2017
S. Lee	Shawn Lee, email: Comments for Draft EIR for Reg 11 Rule 18 and Reg 12 Rule 16, May 7, 2017
Shell	Keith M. Casto, letter: Draft Environmental Impact Report ("DEIR") for Proposed BAAQMD Rules 11-18 and 12-16, May 5, 2017

S. Ardito	Steven L. Ardito, letter: Comments relating to environmental analysis for Rules11-18 and 12-16, May 7, 2017
T. Finley	Tamar Finley, email: i want enforceable numeric caps on refinery emissions at today's levels, April 18, 2017
T. Yu	Tiffany Yu, email: Your Draft Environmental Impact Report for Rule 12-16 and Rule 11-18, May 8, 2017
WSPA	Bob Brown, Western States Petroleum Association: letter: Comments of the Western States Petroleum Association on Proposed Rule 12-16, and Draft Environmental Impact Report for Proposed Rules 11-18 and 12-16, May 8, 2017

1-Hour SO$_2$ Design Value Trend
Concord
Crockett
Bethel Island
Chevron Castro
Chevron Gertrud
Chevron Golden Gate
ConocoPhillips Crockett
ConocoPhillips Cummings Skyway
ConocoPhillips E Refinery
ConocoPhillips Hillcrest
ConocoPhillips Tormey
Shell Ace Hardware
Tesoro Chenery
Tesoro Gun Club
Tesoro Waterfront
Valero Gas Station
Valero Warehouse
Valero Wastewater
2010 1-Hour SO2 NAAQS
1-Hour SO$_2$ Design Value (ppb)
90
80
70
60
50
40
30
20
10
0
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
Design Value Year


24-Hour PM$_{2.5}$ Design Value Trend
San Pablo
Concord
Vallejo
San Rafael
San Jose Jackson
Oakland East
Livermore
San Francisco
Napa
Gilroy
Point Richmond
North Richmond
Atchison
2006 24-Hour PM2.5 NAAQS
24-Hour PM$_{2.5}$ Design Value (µg/m^3)
0
5
10
15
20
25
30
35
40
45
50
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
Design Value Year


Annual $PM_{2.5}$ Design Value Trend
San Pablo
Concord
Vallejo
San Rafael
San Jose Jackson
Oakland East
Livermore
San Francisco
Napa
Gilroy
Point Richmond
North Richmond
Atchison
1997 Annual PM2.5 NAAQS
2013 Annual PM2.5 NAAQS
Annual $PM_{2.5}$ Design Value (µg/m³)
16.0
14.0
12.0
10.0
8.0
6.0
4.0
2.0
0.0
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
Design Value Year

ADVISORY COUNCIL EFFICACY OF GREENHOUSE GAS CAPS ON BAY AREA REFINERIES

KEY QUESTION BEFORE THE COUNCIL

Air District staff asked the Advisory Council to consider the following question:

> ***"What is the efficacy of imposing greenhouse gas caps on Bay Area refineries?"***

PREAMBLE

While the key question focuses on refinery greenhouse gas (GHG) emissions and global climate change, the Council recognizes that there are also community concerns about the effects of refinery toxics and criteria pollutant emissions on health risk, particularly near refineries. We view both climate and health risk considerations as crucially important, and the Council's opinions are meant to address both.

With respect to climate, we conclude that refinery GHG caps are unlikely to be effective in mitigating global climate change. That conclusion, however, is not an endorsement of inaction. The Council strongly supports coordinated climate protection efforts by the Air District, CARB, USEPA, and others, and the Council views as urgent further efforts by all to take effective steps toward climate protection.

With respect to health risk, we conclude that toxics and criteria pollutant health risk are most effectively addressed directly, through established health-based programs and measures such as draft rule 11-18, rather than indirectly as co-benefits of GHG reduction policies.

CONCLUSIONS

Based on the material that it has considered, its deliberations, and its collective expertise and experience, the Council has reached the following conclusions:

- Conclusion on Key Question: The Council concludes that facility-level caps on Bay Area refinery GHG emissions are unlikely to be effective in mitigating global climate change. GHG reduction policies are effective in providing climate protection only if total global GHG emissions are reduced, and if leakage occurs (that is, GHG emissions are shifted outside of the Bay Area to other locations instead of being reduced), which is likely with refinery GHG caps, such caps would not provide such protection.
- Policy Recommendation: The Council recommends that the Air District identify, systematically evaluate, prioritize, and adopt Bay Area GHG reduction policies and measures, including ones directed at refineries as appropriate, that are effective in reducing total global GHG emissions, minimize leakage risk, and complement and reinforce GHG reduction measures adopted by CARB (e.g., GHG cap-and-trade and methane reduction programs), USEPA, and others.
- Policy Recommendation: The Council recommends that the Air District address community concerns about toxics and criteria pollutants directly, through established programs, rather than indirectly as co-benefits of GHG reduction policies. The approach embodied in proposed rule 11-18 is consistent with this recommendation.

GUIDING PRINCIPLES

The Council has developed the following guiding principles that it regards as useful when evaluating the efficacy of Refinery GHG caps:

1. Clear goals: The Air District should state its goals clearly. If the goal of a proposed GHG reduction measure, such as a Refinery GHG cap, is climate protection, then that goal should be explicitly stated. If toxics reduction is the goal, that should be stated. If, instead, the goal is to limit or reduce the amount or nature of crude throughput at Bay Area refineries, that is a different goal, and should be clearly stated.
2. Systematic evaluation of policies to ensure that they support the goals: The Air District should align its policies, including refinery-related GHG measures, with its goals and ground them in plausible and workable pathways specific to those goals, and careful of unintended consequences.
3. Evaluation and prioritization of GHG reduction options: The Air District should systematically evaluate and prioritize the effectiveness of Bay Area GHG reduction options. Criteria should include the following:
    - i) Total global GHG emissions must actually be reduced. To ensure effective climate protection benefits, the Air District should adopt policies that truly reduce total global GHG emissions, and not simply displace Bay Area GHG emission elsewhere outside the Bay Area through leakage.
    - ii) GHG regulations should be complementary and non-conflicting. The climate change regulatory landscape is complex. To be most effective, Air District policies should be complementary and non-conflicting with those established by CARB, USEPA, and others. Coordination should include enhanced measurements of GHG emissions.
    - iii) Interactions of GHG and other programs and policies should be evaluated. While GHG reduction policies and toxics and criteria pollutant control programs are often complimentary, they are not always so. It is important that interactions among such programs and policies be evaluated and addressed to maximize health and climate benefits and minimize unintended consequences.

DISCUSSION

It is the mission of the Air District to "create a healthy breathing environment for every Bay Area resident while protecting and improving public health, air quality, and the global climate."

Toward that end, the Air District has regulated toxics and criteria pollutants for over 60 years. During this time, there has been continuous improvement in Bay Area air quality due to Air District efforts, along with those of CARB, USEPA, and others. This process of continuous improvement has incorporated evolving understanding of atmospheric science, toxics and criteria pollutant health effects, and improving emissions control technology. The Air District has acted within a framework of State, Federal and local regulations, while also enacting its own rules.

Over a period of decades, the Air District has implemented a number of effective and proven regulatory programs and adopted rules to ensure that clean air health and other environmental standards are met. Programs specifically directed at toxics include New Source Review of Toxic Air Contaminants, emission and/or performance standards for hazardous air pollutants, the Community Air Risk Evaluation (CARE) Program, and the California Air Toxics "Hot Spots" Program. Programs directed at criteria pollutants include the Multi-Pollutant Clean Air Plan (which also includes GHGs), New Source Performance Standards for new sources, and emission and/or performance standards for existing sources.

The Air District has enacted a number of rules directed specifically at reducing toxics and criteria pollutant emissions from refineries, with additional such rules the subject of currently on-going rulemaking. A significant expansion of community risk-based protection would be provided by draft "Regulation 11, Rule 18: Reduction of Risk from Air Toxic Emissions at Existing Facilities". This rule would improve air quality and reduce toxic emissions from facilities ranging in size from large-scale plants like factories and refineries to smaller operations like back-up generators and gas stations. The Air District estimates that hundreds of facilities throughout the Bay Area may be subject to the proposed rule, which would incorporate recently adopted risk management guidelines and health risk values from the California Office of Environmental Health Hazard Assessment.

Rule 11-18

Under draft Rule 11-18, Air District staff would conduct site-specific health risk screening analyses for all facilities that report toxic air contaminant emissions, and calculate health prioritization scores based on the amount of toxic air pollution emitted, the degree of toxicity of these pollutants, and the proximity of these facilities to local communities. The Air District would conduct health risk assessments for facilities found to have priority scores above a threshold value.

All facilities found to have a cancer risk in excess of 10 in a million or an acute hazard index greater than 1.0 would be required to reduce their risk below 10 in a million and their hazard index below 1.0, or install Best Available Retrofit Control Technology for Toxic Pollutants on all significant sources of toxic emissions.

Because their effectiveness and focus have been amply demonstrated, the Council concludes that toxics and criteria pollutants should be regulated directly through such established programs, rather than indirectly as co-benefits of GHG reduction policies. The most effective place for Bay Area GHG emissions policy is within a comprehensive multi-pollutant strategy that accounts for the realities of conflicting effects, where present, including both co-benefits and dis-benefits.

Climate change is one of the most serious and urgent challenges confronting not just the Bay Area, but the world. That is why, for more than a decade, since 2005, the Air District Board, Staff, and Advisory Council have worked together in efforts that today place the Air District at the leading-edge of climate protection efforts by local agencies in California and throughout the U.S. Programs directed at global climate change include the Climate Protection Program, Regional Climate Protection Strategy, GHG emission inventories, and Plan Bay Area (with the Metropolitan Transportation Commission and others).

In determining the most effective path forward for its climate protection efforts, the Air District works within a framework of existing climate regulations enacted by the State of California, the Federal government, and others. Unlike toxics and criteria pollutants, for which effects of concern typically occur adjacent to emitting sources (tens of meters) or near-downwind (hundreds of meters to several kilometers), the relevant effects of climate change (and the GHGs that cause it) are global. In the Bay Area, such effects will include flooding from sea level rise, and increases in property damage and airborne pollutants from wild fires.

Climate change is one-world in scope, driven not just by GHG emissions from a single facility, localized area, or even a large geographical region, but by the world-wide total of all GHG emissions. While a ton of GHGs emitted anywhere in the world has the same effect on global climate as a ton of GHG emitted in the Bay Area, this is not a rationale for inaction but rather a call for leadership.

> ***The Council strongly supports climate protection efforts by the Air District, State and Federal authorities, and others, and the Council views as urgent further efforts by all to take <u>effective</u> steps to address global climate change.***

To be effective, efforts directed at global climate change must reduce total global GHG emissions. It is not sufficient to reduce GHG emissions in one location if those emissions are simply moved elsewhere to another part of the world, an effect called "leakage." Avoiding leakage, or at least minimizing its risk, is key to ensuring the climate protection effectiveness of adopted policies and measures.

The Council is concerned about the potential for such GHG leakage with refineries. In permitting, refineries, like other stationary sources, are required to install emission controls sufficient to ensure that operations meet clean air toxics and criteria pollutant health standards, even if the refinery were to be operated at its theoretical maximum emission rate. The effect of a GHG cap, especially if set at actual throughput levels that are below permitted maximums, may be to prevent a refinery from processing the volume of crude it would otherwise have processed within its permit. If so, the Council is concerned that leakage will be triggered. Because the petroleum industry is globally integrated, the Council considers it likely that such excess crude over the cap (and the GHGs associated with that production) will be displaced from the Bay Area and relocated to refineries elsewhere, out from underneath the caps and negating their intended climate benefit.

The ready mobility of global refinery production and gasoline shipment re-equilibration, and thus the strong potential for GHG leakage, is illustrated by a recent example in Southern California. In February 2015, an explosion and fire at a large refinery in Torrance shut down the refinery for more than a year. Almost immediately, the loss of gasoline production was made up by large outside shipments.

According to the U.S. Energy Information Administration (October 13, 2015), "Over a five-month period following an explosion at a California oil refinery in February 2015, imports of gasoline into California increased to more than 10 times their typical level, drawing from sources that include India, the United Kingdom, and Russia."

The Council is concerned that merely shifting Bay Area refinery GHG emissions to other locations outside the Bay Area will not truly reduce total global GHG emissions, and as a result, will not provide the climate protection expected and needed. In fact, should such a shift result in additional transport of displaced refinery products, as happened in the Torrance example, the carbon footprint of those products would actually increase.

Concern for leakage is not an excuse for inaction, however. There is much that can and must be done in the Bay Area and elsewhere to reduce total global GHG emissions, including those from petroleum-based sources, and there exist important opportunities for the Air District to provide leadership. The question is not whether to reduce global GHG emissions, but how to do it in a manner that will be effective in mitigating global climate change.

For example, emissions of high global warming potential (GWP) pollutants such as methane are not covered under cap-and-trade when emitted as fugitives, meaning emissions that are unintentional and do not pass through a stack, or other equivalent opening. However, the GWP of methane 34 times greater than that of carbon dioxide. The Air District can play a significant role in addressing fugitive emissions of methane in the Bay Area, whether by accidental discharges or from routine fugitive emissions at facilities.

More generally, the Air District should coordinate with CARB on its Short Lived Climate Pollutant (SLCP) strategy. The strategy addresses emissions of other high-GWP pollutants such as soot (black carbon), fluorinated gases and hydrofluorocarbons. In addition, at the federal level, there is already a Prevention of Significant Deterioration requirement for GHG.

Points of opportunity for Air District refinery focus include:

- Enhanced monitoring of high-GWP emissions such as methane
- Enhanced regulation of fugitive emissions of high-GWP emissions such as methane
- Enhanced energy efficiency reviews
- Increased focus on energy efficiency in the definition of GHG best practices and best available control technology

The Air District can also influence Bay Area GHG emissions in other ways:

> ***The Council strongly encourages Air District efforts to identify, systematically evaluate and prioritize, and adopt Bay Area GHG reduction policies and measures, including ones directed at refineries as appropriate, that are effective in reducing total global GHG emissions, minimizing leakage risk, and complementing and reinforcing GHG reduction measures adopted by CARB (e.g., GHG cap-and-trade and methane reduction programs), USEPA, and others.***

To maximize climate protection afforded by policies directed at petroleum-based GHGs, it is important to target both stationary and mobile sources. For example, in the Bay Area, as elsewhere in California, petroleum-fuelled mobile sources collectively are the largest emitters of GHGs. Approximately 80% of the GHGs emitted over the life-cycle of a barrel of petroleum used to produce gasoline are produced when that gasoline is burned as fuel in motor vehicles, that is, from “tank-to-wheels.” By comparison, refining accounts for about 12% of those petroleum life-cycle GHGs.

Relevant refinery GHG emissions information includes the following:

- Refineries emit approximately 16% of Bay Area GHG emissions, compared to transportation sources, which emit about 38%, two-thirds of which is from passenger cars/trucks.
- Refineries are five of the six largest emitters of GHGs among Bay Area stationary sources.
- Refining accounts for approximately 12% of the well-to-wheels GHG emissions from internal combustion engine transportation.
- Burning of fuel in vehicle engines (tank-to-wheels) accounts for approximately 80% of the well-to-wheels GHG emissions for internal combustion engine transportation.
- Refinery GHG emissions are primarily from process heaters and boilers, and from fluid catalytic cracking units, which together emit more than 90% of refinery GHGs. Global emissions of

> petroleum-based GHGs can be reduced most directly by reducing demand for petroleum-based fuels. Past experience suggests that gasoline demand is inelastic, that is, it is relatively insensitive to gasoline price over a broad range. This suggests use of alternate strategies to reduce demand and increase efficiency may be appropriate.

> Petroleum fuel demand can be reduced by lowering vehicle miles travelled (VMT) through a variety of local Bay Area policies, including, for example, ones that encourage more efficient and transportation-integrated land use (e.g., Plan Bay Area, Smart Growth) and increased availability and use of public transit (e.g., increased transit funding, bike and car share programs, expanded public education). Many of these policies are already key elements in plans to reduce toxics and criteria pollutant air pollution, and will be compatible with efforts to reduce GHG emissions.

In addition to petroleum fuel demand reduction, complementary measures are being adopted that reduce per-vehicle-mile GHG emissions. Such measures include a requirement for lower carbon fuel intensity (e.g., Low Carbon Fuel Standard), more stringent mileage standards for petroleum-fuelled vehicles, and replacement of petroleum-fuelled vehicles with cleaner, non-petroleum-fuelled alternatives (e.g., electric vehicles, ideally powered by renewable-generated electricity). Current paths to reduce carbon emissions in the Bay Area will not attain the stated 2050 goals without significant additional policies aimed at decarbonizing power sources. Therefore, the Air District should support a wide variety of policies to accomplish this goal, including policies to research and develop technologies, including for instance carbon capture and sequestration.

Certain individual sources of GHGs and/or other pollutants are known to release atypically large emissions, disproportionately larger than other similar sources and materially higher than estimated using standard bottom-up GHG emission estimation methods. The Air District should consider a find-and-fix program to identify and repair GHG "super-emitters," if and where present, reducing non-inventory "hidden" (but real) GHG emissions from such sources.

ATTACHMENT A
Advisory Council Members

Pursuant to California Health and Safety Code § 40260-40268, the Advisory Council consists of seven members "skilled and experienced in the fields of air pollution, climate change, or the health impacts of air pollution," and the Air District Board Chair (or their representative) as an ex-officio member. Council members are appointed by the Air District Board and are "selected to include a diversity of perspectives, expertise, and backgrounds." Members of the Advisory Council include:

Member	Background	Air Pollution	Health	Climate
Stan Hayes	Member, Advisory Council (1995-2007, 2009-) and former chair; emeritus Principal, Ramboll Environ; air-related research consulting	X	X	X
Severin Borenstein	Professor of Business Administration and Public Policy, Haas School of Business, University of California, Berkeley			X
Tam Doduc	Member and former chair, State Water Resources Control Board; served as Deputy Secretary, Cal/EPA, directed environmental justice	X	X	
Robert Harley	Professor and Department Chair, Civil and Environmental Engineering, University of California, Berkeley	X		X
Michael Kleinman	Professor, Environmental Toxicology, Co-Director, Air Pollution Health Effects Laboratory, Adjunct Professor, College of Medicine, University of California, Irvine	X	X	
Tim Lipman	Co-Director, Transportation Sustainability Research Center, energy and environmental technology, economics, and policy researcher and lecturer; University of California, Berkeley	X		X
Jane CS Long	Chair, California's Energy Future Committee, California Council on Science and Technology			X

ATTACHMENT B

Process and Speakers

DELIBERATIVE PROCESS

Presentations to the Council were made by more than a dozen speakers from the Air District, CARB, the California Energy Commission (CEC), and various interested stakeholders. A full list of speakers is provided below.

Speakers included Richard Corey, Executive Officer, CARB; Jack P. Broadbent, Executive Officer/APCO and other senior management and staff of the Air District; and senior representatives of Communities for a Better Environment, 350 Bay Area (by letter), the California Council for Environmental and Economic Balance, and the Western States Petroleum Association.

Council deliberation was conducted in five full-day meetings on December 3, 2015, and February 3, April 25, July 19, and October 3, 2016.

SPEAKERS

- Bay Area Air Quality Management District
  - Jack P. Broadbent, Executive Officer/APCO
  - Brian Bunger, General Counsel
  - Jeff McKay, Deputy APCO
  - Jim Karas, Director of Engineering
  - Henry Hilken, Director of Planning and Climate Protection

- California Air Resources Board
  - Richard Corey, Executive Officer
  - Sam Wade, Chief, Transportation and Fuels Branch
  - Jason Gray, Manager, Climate Change Market Monitoring Section

- California Energy Commission
  - Gordon Schremp, Senior Fuels Specialist

- Stakeholders
  - Communities for a Better Environment (CBE) – Greg Karras
  - 350 Bay Area – Letter
  - California Council for Environmental and Economic Balance (CCEEB) and Western States Petroleum Association (WSPA) – Bill Quinn and Berman Olbaldia; Gary Rubenstein, Sierra Research on behalf of CCEEB and WSPA