BAY AREA
AIR QUALITY
MANAGEMENT
DISTRICT

Draft Regulation 13: Climate Change Pollutants

Rule 1: Petroleum Refinery Carbon Intensity Limits or Facility-Wide GHG Emission Limits

Prepared by the staff of the
Bay Area Air Quality Management District

DRAFT WORKSHOP REPORT
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The following people participated in the Air District workgroup to develop this draft rule. Each deserves recognition for their important contributions.

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I. INTRODUCTION AND SUMMARY

The Bay Area has five large-scale petroleum refineries that, along with their associated facilities, such as hydrogen plants, contribute significantly to greenhouse gas (GHG), criteria pollutant and toxic air contaminant emissions. Though refinery emissions have stabilized or decreased over time, Bay Area residents have expressed concern about the health, environmental and climate impacts of these emissions. Furthermore, there is a possibility that operational changes at refineries, such as the processing of new crude slates, could increase these emissions even at current levels of production.

Oil refineries constitute the largest stationary source of GHG emissions in the Bay Area. Together, the five Bay Area refineries and their support facilities emitted approximately 16 percent of all Bay Area GHG emissions in 2015. Since fuel combustion is responsible for most of these emissions, a logical initial action would be to find opportunities to increase the efficiency of combustion processes to reduce fuel consumption. Fuel use reduction would result in direct emission reductions of GHGs, and to a much lesser extent, criteria and toxic pollutants. Since this approach also leads to fuel cost savings, most of the needed investment can be recovered over time.

The Air District will implement a Basin-wide Combustion Strategy to systematically address emissions from stationary combustion as part of its climate efforts outlined in the draft 2017 Clean Air Plan. As a first step in the Combustion Strategy, the Air District is proposing a new rule, Draft Regulation 13, Rule 1 (Rule 13-1) to limit refinery carbon intensity to a level consistent with current operations. Carbon intensity is the amount of greenhouse gases emitted per unit of input or output, and can be an indication of the energy and process efficiency of a refinery when compared to similar facilities. Draft Rule 13-1 is designed to address community concerns about potential emissions increases at refineries by monitoring and limiting the intensity of combustion emissions to current levels. However, the carbon intensity limit allows production increases that might be needed and thus minimizes interference with the transportation fuels market. By using a carbon intensity limit, this draft rule also seeks to complement and serve as a backstop for State climate efforts, which are anticipated to require refinery carbon intensity reductions equivalent to a 20% reduction in GHG emissions by 2030.

Draft Regulation 13, Rule 1 includes the following:

- a definition of carbon intensity for the refining sector, total refinery GHG emissions divided by the total feedstock volume in a calendar year
- a carbon intensity limit for each refinery consistent with current operations
- a mass-based GHG emissions limit as an alternate compliance option
- a mechanism to incentivize known energy improvement projects

This workshop report is a summary and explanation of Draft Rule 13-1, how the Air District staff would expect to implement this rule, and staff's initial assessment of the rule. Section I provides background information on petroleum refining and its effects on air quality, on carbon intensity, and on State efforts relevant to refinery emissions. Section II describes the context and purpose of this draft rule, explains the data gathering and calculation process used to determine the rule compliance limits, and provides details on annual compliance determination.

The Air District invites all interested members of the public to review the draft new regulation and this Workshop Report. Air District staff seeks input from all impacted stakeholders on the draft rule language and our initial assessment of the draft rule. The Air District will also be conducting a series of meetings around the Bay Area to discuss Draft Rule 13-1 directly with the public and industry stakeholders. Air District staff will continue to accept written feedback until April 21, 2017, and may revise the draft rule based on the input received. Air District expects to present a final proposal to the Air District's Board of Directors in September 2017.

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II. BACKGROUND

A. Petroleum Refining Overview

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

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)

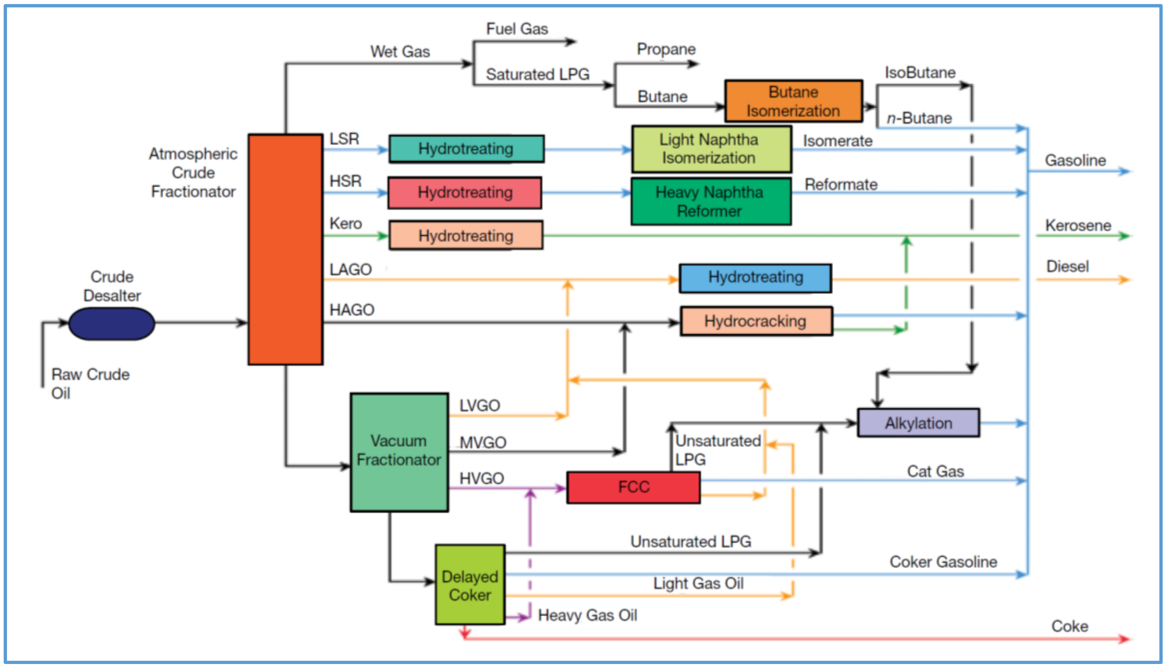
The three affected, refinery-related support facilities are:
1. Air Products and Chemicals hydrogen plant, Martinez (BAAQMD Plant #10295)
2. Air Liquide hydrogen plant, Rodeo (BAAQMD Plant #17419)
3. Martinez Cogen, L.P. (BAAQMD Plant #1820)

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

1. 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 gas 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: Mixed butanes 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 light gas oils 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.

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.

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 potential 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.

3. Petroleum Refining Processes

Refineries are composed of the general processes and associated operations discussed below.

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 gas oil fractions are converted to high-octane gasoline, jet fuel, and diesel fuel, gasoline by various processes. These processes, such as cracking, coking, and vis-breaking (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 hydro-desulfurization, 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. 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 in compositions. 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 find a similar mixture of crude oils, or make changes to their facilities to accommodate different sources of crude oil with different compositions to maintain current production levels.

4. 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.

Criteria pollutants 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 the California Air Resources Board (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 $PM_{2.5}$ (also known as Reactive Organic Compounds (ROGs); and
- Sulfur dioxide (SO_2).

Each of these criteria pollutants is emitted by petroleum refineries. In general, criteria pollutants are regional in nature, with the exceptions of SO_2 and in some cases particular matter, in that emissions of these compounds affect a large region near where they are emitted, although they can also have more localized affects.

Toxic pollutants, also known as toxic air contaminants (TACs), 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). 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 (Rule 11-18 or “Toxic Risk Reduction Rule”). TACs generally have localized affects, in that they are more likely to have greater impacts near where they are emitted.

Climate pollutants (greenhouse gases or GHGs) are emissions that contribute to 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 (AB32). The climate pollutants emitted from petroleum refineries include CO_2, CH_4, and N_2O. In general, climate pollutants are global in nature, in that emissions affect the entire planet. Reduction of GHGs must occur on a global level to reduce the effects of climate change.

5. Impact of Crude Slate Changes on Refinery Emissions

Bay Area refineries have traditionally processed crude oil from the San Joaquin Valley and the North Slope of Alaska, supplemented with foreign crudes. San Joaquin crude is heavy and sour, Alaskan crude is more moderate and sour, and foreign crudes are selected to fit the specific processing capabilities at each refinery. Heavy sour crudes require intensive processing to convert the crude oil into transportation fuels. More intensive processing leads to higher emissions of GHG and other combustion pollutants. For example, heavier crude oils need heat, pressure and chemical treatment to break down into the smaller molecules needed for gasoline, diesel, and jet fuel. The burning of various fossil fuels to create this heat and pressure accounts for most of the criteria pollutants and roughly one half of the GHG emissions. More sulfurous crudes or crudes with more nitrogen require hydrogen to remove the sulfur and nitrogen. The manufacture of hydrogen is very carbon intensive, accounting for as much as half of the GHG emissions from the refining processes. Given the current process for creating hydrogen (methane reformation), more hydrogen demand means more GHG emissions.

Both of Bay Area's traditional sources of crude oil are in decline. Refineries are going to have to replace the California and Alaskan crudes with a mix of other sources of crude oil feedstock. There are some sources available to the refineries that are even heavier and more sour (or contain more nitrogen) than California and Alaskan crude, such as Canadian tar sands crude and some Venezuelan crudes. In addition, there are some sources of crude that are lighter and sweeter than California and Alaskan crude.

Changing crude slates can also lead to changes in toxic emissions. Heavier crudes tend to have more toxic metals, which can be emitted from the fluid catalytic cracking units when petroleum coke is burned off the catalyst. Lighter, sweeter crudes (such as shale oil from fracking) tend to have higher levels of benzene and hydrogen sulfide (H_2S), which can be emitted from storage tanks and equipment leaks.

The intent of Rule 13-1 is to ensure that refinery emissions do not increase per barrel of crude oil processed. Rule 13-1 is not intended to address toxic pollution. Toxic pollution impact from refineries and other significant stationary sources in the Bay Area will be addressed and reduced under draft Rule 11-18.

B. Refinery Air Pollution in Context

Refineries are a significant source of air contaminants in general. In the counties where the refineries are located, their emissions are more significant, 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%**

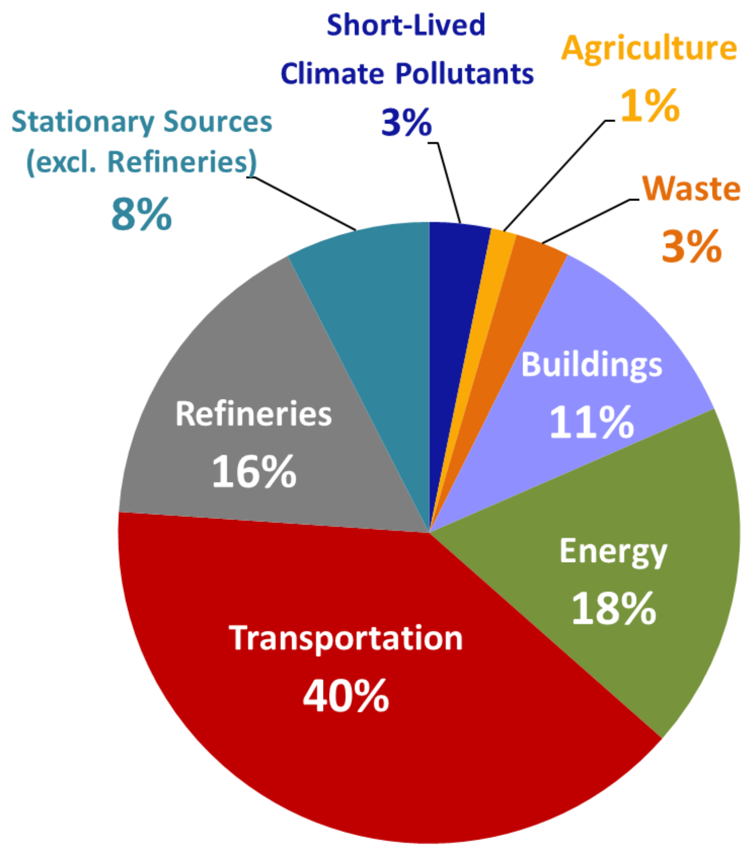
Table 2: Emissions of Relevant Pollutants by Source Category for Contra Costa and Solano Counties

Source Category	Emissions							
	$PM_{2.5}$		Anthropogenic ROG		NO_X		SO_2	
	(tons/yr)	%	(tons/yr)	%	(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 Emissions	**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 1: 2015 Bay Area GHG Emissions by Source Category (Total = 88 MMT CO_2e using 100 year GWP)



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 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.

C. Refinery Carbon Intensity and State Efforts

The rule described in this workshop report, Draft Rule 13-1, seeks to limit the carbon intensity of the Bay Area petroleum refineries. Carbon intensity (CI) is the amount of CO_2 emitted for each unit of product generated or input processed (e.g., pounds of CO_2 emitted per kW of electricity generated for a power plant). In general, the carbon intensity of a facility can be an indication of its efficiency when compared to similar facilities in the same industrial sector.

Oil refineries use large quantities of energy to convert crude oil into transportation fuels, mainly supplied from the combustion of crude oil and natural gas, and from grid electricity. The most thorough methodology to calculate the carbon intensity for the refining sector needs to account for the CO_2 emissions from all energy inputs. The carbon intensity of the refining process can be characterized using various approaches. The simplest way to express carbon intensity is on a simple-barrel basis, or CO_2 emitted per barrel of crude oil processed. There are alternative methods that are more complex. Since refineries produce several different products (e.g., gasoline, diesel and jet fuel), the standard could also be expressed in pounds of CO_2 per gallon of product. A metric such as gasoline-equivalent-gallon could be used to aggregate all the products into “gallons of product”. The complexity-weighted barrel (CWB), developed by Solomon and Associates, is a more commonly-recognized methodology [1]. This metric takes into consideration the complexity of the refinery’s processes to allow a fair performance comparison between refineries. However, the data needed to calculate the CWB or total gasoline-equivalent-gallons is difficult to obtain or considered confidential by refineries. The Air District has chosen to define carbon intensity for refining using the simple-barrel metric to maintain transparency in the development and enforcement of the draft rule, but input from stakeholders is encouraged to determine if there is a better approach.

Regardless of the specific units chosen to express carbon intensity, one advantage of this approach is that carbon intensity is a rate-based-standard (e.g., CO_2/unit of input) and not an absolute standard (e.g., total CO_2 emissions). Thus, requirements curtailing carbon intensity do not limit production at individual facilities, which minimizes interference with the transportation fuels market.

A hard mass-based cap on GHG emissions, as opposed to the rate-based cap proposed in draft Rule 13-1, would limit production at individual refineries. Limiting refinery production could cause problems if gasoline consumption continues to increase. Local refineries would be unable to meet local demand, resulting in importation of transportation fuels from overseas which would drive up costs and may result in net increases in GHG emissions due to transport emissions. If gasoline consumption decreases significantly, a hard mass cap on GHG emissions could cause different problems. If gasoline demand is reduced by 40-50% due to a change to electric vehicles, California wouldn’t need as many refineries. In this scenario, some refineries may need to increase production to make up for other refineries shutting down. A hard limit on each refinery’s GHG emissions interferes with this process. Draft Rule 13-1 focuses on the amount of emissions per unit of material processed, serves as a backstop to ensure that the emissions intensity does not increase while minimizing interference in the uncertain transportation fuels market.

Furthermore, the use of carbon intensity in a regulation for the refining sector, as proposed in Draft Rule 13-1, is compatible with the latest State climate efforts, described below.

1. CARB Scoping Plan

The California Global Warming Solutions Act of 2006 (AB 32) requires a 20 percent reduction in the State’s GHG emissions below 1990 levels, by 2020. AB 32 tasked the California Air Resources Board (CARB) with developing a Scoping Plan describing the State’s approach to achieve that goal, and to update it every five years. The Scoping Plan, first approved by CARB in 2008, relied on an economic sector framework to identify a range of GHG reduction actions. The Scoping Plan identified a cap-and-trade program as one of the strategies that could be employed to meet the State’s 2020 GHG reduction goals, alongside direct regulations, voluntary actions and alternative compliance mechanisms. The First Update to the Climate Change Scoping Plan was approved by CARB in 2014. This plan built upon the initial Scoping Plan with new strategies and recommendations, and with the development of focus areas that spanned more than one economic sector (e.g., short-lived climate pollutants). In 2016, the Legislature passed SB 32, which codified into law the State's mid-range climate target set by Executive Order B-30-15. SB 32 requires California to reduce its GHG emissions 40 percent below 1990 levels by 2030. Along with SB 32, the Legislature passed companion legislation AB 197, which requires CARB to consider the social costs of GHG emissions and to prioritize direct emission reductions at large stationary sources, and from mobile and other sources. In addition, AB 197 requires annual posting of GHG, criteria and toxic emissions at the local and sub-county levels for stationary sources, and at least at the county level for mobile sources. These requirements are intended to protect the State's most impacted and disadvantaged communities and to ensure the transparency of the State's GHG reduction actions.

Recently, CARB released the proposed 2017 Climate Change Scoping Plan Update to reflect the 2030 target and priorities set by SB 32 and AB 197 [2]. CARB is planning to submit this plan to its Board for adoption on June 23, 2017. The Proposed Scenario includes a few initiatives that affect the refining sector directly, including a Refinery GHG Reduction Measure. The proposed direct measure to achieve a 20 reduction in GHG emissions in the refinery sector would require all refineries to become as efficient as California's most efficient existing refinery on a simple-barrel basis[1]. The regulation would not limit mass GHG emissions, but rather require a decrease in carbon intensity through actions such as increasing energy efficiency, switching to lighter crude slates, and boiler electrification.

The proposed 2017 Scoping Plan highlights the Cap-and-Trade and the Low Carbon Fuel Standard (LCFS) programs as instrumental in addressing GHG emissions from the refining and transportation sectors. These programs are described below.

a. Cap-and-Trade

CARB's Cap-and-Trade program is a market-based regulation designed to reduce GHG from multiple sources. The program establishes a cap on sources representing about 85% of California's GHG emissions. The cap is set to decline approximately 2 percent each year beginning in 2013 and eventually 3 percent from years 2015 – 2020. Facilities subject to this cap can trade allowances to emit GHGs to minimize compliance costs. The Cap-and-Trade program started in 2013 with industrial facilities and electricity generators emitting over 25,000 $MTCO_2e$ annually. Starting in 2015, the program added fuel distributors. Covered entities are required to report annual GHG emissions since 2008 through CARB's Mandatory Greenhouse Gas Emissions Reporting Regulation (MRR) [3].

The proposed 2017 Scoping Plan recommends continuing, extending and strengthening the Cap-and-Trade program, in combination with direct emission reduction measures such as the Refinery GHG Reduction Measure, to deliver GHG emission reductions that

[1] ARB will also evaluate the complexity-weighted barrel as a metric for the Refinery Reduction Measure.

support meeting the 2030 climate goal.

b. Low Carbon Fuel Standard

The LCFS regulation works with the Cap-and-Trade, Advanced Clean Car[2], and Sustainable Communities (SB 375)[3] programs to encourage the use of cleaner, low-carbon fuels and therefore reduce transportation GHG emissions. The LCFS regulation, originally adopted by CARB in 2009, is designed to reduce the carbon intensity (CI) of transportation fuels by at least 10% by 2020. The LCFS uses CI values, measured in grams of CO_2 equivalent per megajoule[4] (g CO_2e/MJ of fuel energy), to quantify the lifecycle GHG emissions associated with transportation fuels. The lifecycle analysis of transportation fuels includes emissions related to their production (e.g., GHG emissions associated with oil wells for crude oil), transportation (e.g. from the oil well to the refinery), refining, and fuel combustion in vehicles. The LCFS regulation was amended in 2011, and later re-adopted in 2015. The proposed Scoping Plan has proposed an 18% reduction in CI by 2030.

The 2011 amendments to the LCFS included using a California Average Crude Oil approach to avoid increases in the average CI of the crude oils that California refineries process. For the California Average Crude Oil approach, ARB set a baseline average CI for all the crudes processed in California refineries in 2010 and calculates the CI for subsequent years' crude slates for comparison with the baseline. If the average crude CI in any subsequent rolling three-year period exceeds the 2010 baseline average CI, all California refineries are assessed an incremental deficit for which they must compensate by acquiring additional low-CI fuels or LCFS credits. The California Average Crude Oil approach applies to the refining industry as a whole and not to individual refineries. All refineries are assigned the same CI value in the LCFS (13.94 gCO_2e/MJ for gasoline and 15.33 gCO_2e/MJ for diesel). In other words, the contribution to the total CI from refining transportation fuels is the same for all refineries. As such, ARB does not track changes in the carbon intensity of crude processing at the individual refineries.

Since all refineries are assigned the same CI value, CARB developed two provisions within the LCFS to give refineries credits for reducing their onsite GHG emissions at the refinery level. The first provision, the refinery investment credit pilot program (RICPP), gives credits to refineries that reduce GHG emissions at their facility in the production of gasoline or diesel. A qualifying RICPP project must achieve a CI improvement from the comparison baseline of at least 0.1 gCO_2e/MJ. The second provision, the renewable hydrogen refinery credit pilot program (RHRCPP), gives credits to refineries that reduce GHG emissions through the use of renewable hydrogen in the production of gasoline or diesel fuel. In order to qualify for the RHRCPP, the renewable hydrogen must replace a minimum of one percent of all fossil hydrogen used annually in the production of California Reformulated Gasoline Blendstock for Oxygenate Blending (CARBOB) or diesel fuel.

[2] This program sets California vehicle emission requirements for model years 2015-2025. More information available at: https://www.arb.ca.gov/msprog/acc/acc.htm
[3] This program links transportation, housing and climate policy. More information available at: https://www.arb.ca.gov/cc/sb375/sb375.htm
[4] Megajoule is a unit of energy, similar to kilowatt hours or British Thermal Units (BTUs)

The LCFS program is one of the State's key efforts to reduce GHG emissions from the transportation sector by reducing the lifecycle CI of transportation fuels. Thus, the LCFS accounts for emissions released upstream (fuel extraction) and downstream (fuel consumption) of the oil refining process. The LCFS regulation also has a mechanism to maintain the average CI of California refineries as a group, and even incentivizes decreases in CI at individual refineries through voluntary credit programs. However, the LCFS is not designed to prevent CI increases at any individual refinery, such as Bay Area refineries.

III. DRAFT NEW REGULATION 13, RULE 1: PETROLEUM REFINERY CARBON INTENSITY LIMITS OR FACILITY-WIDE GHG EMISSION LIMITS

Draft Regulation 13, Rule 1 seeks to complement and serve as a backstop for State climate efforts, which are anticipated to require a 20% reduction in refinery GHG emissions by 2030.

The following sections describe the context and purpose of this draft rule, explain the data gathering and calculation process used to determine the rule compliance limits, and provide details on annual compliance determinations. Draft Rule 13-1 was conceptualized and developed as part of the Basin-wide Combustion Strategy, described below.

A. Basin-wide Combustion Strategy

The Air District will implement a Basin-wide Combustion Strategy to address emissions from stationary combustion, the largest contributor of GHG emissions within the Air District's direct regulatory jurisdiction. This effort is part of the Regional Climate Protection Strategy in the draft 2017 Clean Air Plan, released by the Air District in January 2017 for public review [4]. The Combustion Strategy is identified as control measure SS18 in the Plan.

Though many stationary sources of combustion emissions are already well-controlled as a result of existing Air District regulation targeting criteria and toxic pollutants, combustion from stationary sources still accounts for over half of all GHG emissions in the Bay Area. Combustion emissions from all stationary sources in the Air District are roughly 40 million metric tons of carbon dioxide equivalent ($MMTCO_2e$), including combustion for residential and commercial uses (approximately 10 $MMTCO_2e$), and combustion at industrial facilities such as oil refineries, power plants and cement plants (about 30 $MMTCO_2e$). Fuel combustion is also a significant source of criteria pollutants and, to a lesser extent, toxic air contaminants, which can exacerbate health risks. Sources that burn gaseous fuels produce nitrogen oxides and particulate matter (PM). Nitrogen oxides are currently well controlled. PM occurs from poor combustion, and is generally limited by ensuring good combustion by monitoring carbon monoxide emissions, another by-product of poor combustion. For these sources, the best approach is to burn less fuel. This reduces criteria pollutants, toxic pollutants and GHG. It also results in fuel cost savings.

The first phase of the strategy would evaluate carbon intensity caps for all major industrial combustion sources in the region, as an immediate action to prevent GHG emissions increases at current levels of production. Nearly 75 percent of CO_2 emissions from industrial combustion in the Bay Area comes from the refining of transportation fuels, the generation of electricity and the production of cement. Each of these key industries would be subject to a carbon intensity standard that makes the most sense for that industry. After defining a carbon intensity calculation standard for each sector, caps would be set on a facility-by-facility basis at a level consistent with current operations, with reasonable allowance for year-to-year variation. Regulation 13, Rule 1 constitutes the first effort in phase one of the combustion strategy, addressing combustion emissions from petroleum refining.

The second phase of the strategy would involve developing source-specific regulations to reduce combustion emissions through increased efficiency. Given the wide variety of combustion emissions sources, regulatory approaches to reduce combustion emissions through increased efficiency must be tailored to the specific sector and equipment type. Thus, this phase will occur over a longer time period.

B. Purpose of Regulation 13-1

The purpose of Draft Regulation 13, Rule 1 is to limit combustion emissions from petroleum refineries and associated support facilities to a level consistent with current operations. Draft Rule 13-1 represents the first step in the Air District's combustion strategy, focusing on the largest source of combustion emissions in the region: petroleum refining.

The overarching goals of this rule are to protect the climate and the region's air quality. By limiting carbon intensity, this draft rule uses carbon dioxide (CO_2) emissions as an indicator for combustion pollutants, which include criteria and toxic air pollutants.

Draft Rule 13-1 is designed to address community concerns about potential increases of GHG emissions that could result from operational changes at Bay Area refineries. It locks refineries into their current carbon intensity at current levels of production capacity. However, the carbon intensity limit allows production increases and thus minimizes interference with the transportation fuels market.

C. Data Gathering

Draft Rule 13-1 sets either a carbon intensity limit or an alternate annual GHG mass emission limit for each affected facility. This section discusses the sources of the data used to calculate both limits. The calculation methodology is discussed in the next section.

1. Total Refinery GHG Emissions

To account for all GHG emissions associated with refining crude oil and non-crude feedstocks into high-value products, Air District staff will include emissions associated with refining processes as well as with any required inputs, such as electricity from the grid, that create GHG emissions. These inputs include net imports of power, hydrogen and steam.

a. Refinery GHG Emissions

Facility-wide GHG emissions will be obtained from CARB's greenhouse gas inventory for each individual refinery. These emissions include only those directly produced at the site. CARB's GHG inventory is based on data reports subject to the California's Mandatory Greenhouse Gas Emissions Reporting Regulation (MRR). MRR establishes uniform calculation methods across industry sectors, provides procedures for quality control, and requires third-party verification [3]. CARB releases facility GHG emissions data collected through the MRR near the end of each calendar year, detailing emissions released during the previous calendar year. These data are publicly available through CARB's MRR website[5], which allows access to facility GHG data for all years since 2008.

b. Net Imports of Power, Hydrogen and Steam

Refinery GHG emissions reported in CARB's GHG inventory will be adjusted to include net imports of power, manufactured hydrogen and steam from any support facilities or external entities. To this end, Rule 13-1 will require refineries to provide any information needed for these adjustments, including relevant properties of these net imports (e.g., megawatt-hours of electricity imported, volume of imported hydrogen, and pounds, pressure and temperature of imported steam) for each support facility and each external entity that provides power, manufactured hydrogen or steam. Facility-wide GHG emissions for support facilities, such as cogeneration plants or hydrogen plants, will also be obtained from CARB's GHG inventory. These emissions will be apportioned to individual refineries based on the respective share of each refinery in the facility's output. Equations 1 through 3 will be used to calculate GHG emissions associated with power, manufactured hydrogen or steam imported to each refinery from support facilities:

$$\text{Imported Power GHG Emissions (in MTCO}_2\text{e)} = \frac{\textit{CARB GHG Emissions from Support Facility Source}\ (\text{MTCO}_2\text{e})}{\textit{Total Megawatt-hrs Power from Support Facility Source}} * \textit{Megawatt-hrs of Imported Power} \qquad \textbf{Eqn. (1)}$$

$$\text{Imported Hydrogen GHG Emissions (in MTCO}_2\text{e)} = \frac{\textit{CARB GHG Emissions from Hydrogen Manufacturing Source}\ (\text{MTCO}_2\text{e})}{\textit{Total Million SCF Hydrogen Produced from Manufacturing Source}} * \textit{Million SCF of Imported Hydrogen} \qquad \textbf{Eqn. (2)}$$

$$\text{Imported Steam GHG Emissions (in MTCO}_2\text{e)} = \frac{\textit{CARB GHG Emissions from Steam Source}\ (\text{MTCO}_2\text{e})}{\textit{Total Million BTU of Steam from Steam Source}} * \textit{Million BTU of Imported Steam} \qquad \textbf{Eqn. (3)}$$

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

For net imports from entities that supply several customers, Rule 13-1 will calculate GHG emissions by multiplying the GHG emission factor and the quantity of imported power for the same year, as shown in Equation 4 below.

$$\text{Imported Power GHG Emissions } (\text{MTCO}_2\text{e}) = GHG\ Emission\ Factor\ (in\ MTCO_2e/\ Megawatt\text{-}hr) * Megawatt\text{-}hrs\ of\ Imported\ Power \quad \textbf{Eqn. (4)}$$

The GHG emission factor used will be based on the most recent available, evidenced-based GHG emission factor applicable to the given year. For example, for net power imported during the baseline years (2013 – 2015) from the largest utility in the Bay Area, Pacific Gas & Electric (PG&E), an average GHG emission factor of 0.194 CO_2e/MWh from PG&E will be used[6]. This value was calculated for the year 2013 and verified by a third-party. It is the most recent available GHG emission factor for power distributed by PG&E at the time of this report.

Equation 5 shows how GHG emissions from net imports are incorporated into the Total Refinery GHG Emissions. Annual Total Refinery GHG Emissions will be calculated as follows:

$$\text{Total Refinery GHG Emissions } (\text{MTCO}_2\text{e}) = CARB\ Refinery\ GHG\ Emissions + Imported\ Power\ GHG\ Emissions + Imported\ Hydrogen\ GHG\ Emission + Imported\ Steam\ GHG\ Emisions \quad \textbf{Eqn. (5)}$$

c. New Regulatory Requirements

Draft Regulation 13-1 does not provide a mechanism to adjust the Refinery GHG Emissions based on GHG emissions increases resulting from any new Federal, State, local or Air District regulation requirement implemented in the previous year. However, the Air District is soliciting comment on this issue.

d. Air District Permits

Currently, Draft Rule 13-1 does not adjust Total Refinery GHG Emission for any GHG emissions increases or reductions from facility changes with Operating Permits that comply with Regulation 2, Rule 2. Air District staff believes that the carbon intensity limit provides sufficient flexibility for refiners. However, the Air District is soliciting comment on this issue.

2. Refinery Throughput

Once each refinery's total GHG emissions have been calculated for a given calendar

[6] Source: https://www.pge.com/includes/docs/pdfs/shared/environment/calculator/pge_ghg_emission_factor_info_sheet.pdf

year, the carbon intensity is calculated by dividing these emissions by the refinery throughput for that year. The refinery throughput is the sum of the crude oil volume and the non-crude oil feedstock volume processed during a given calendar year, as shown in Equation 6. These volumes are reported by refineries to the Air District as required in Air District Rule 12-15, section 408.

$$\text{Refinery Throughput (thousand barrels)} = \textit{Actual Crude Volume} + \textit{Actual Non-crude Oil Feedstock Volume} \qquad \textbf{Eqn. (6)}$$

3. Refinery Peak Processing Volume

The refinery peak processing volume of a refinery is used to calculate its annual GHG emissions limit, as an alternate compliance option provided in Draft Rule 13-1. It represents the highest actual annual volume of crude oil and non-crude oil feedstocks processed at a refinery within the last 10+ years. The refinery peak processing volume is defined as the sum of two quantities: the refinery peak crude volume and the refinery highest actual volume of non-crude oil feedstocks. The refinery peak crude volume is the highest actual volume of crude oil processed at a refinery crude unit during any twelve-month period. This information is reported by the refineries to the California Regional Water Quality Control Board every five years, as required by the National Pollutant Discharge Elimination System (NPDES) permitting regulation [40 CFR, section 122.45(b)(2)]. The refinery peak crude volume can be found in each refinery's NPDES permits, which are public documents[7]. The second quantity required in the calculation is the refinery highest actual volume of non-crude oil feedstocks during the baseline period (2013 – 2015). The annual volume of feedstocks processed at refinery non-crude process units are reported by refineries to the Air District as required in Air District Rule 12-15, section 408, starting with calendar year 2013. Air District staff will subtract any volumes of crude or non-crude oil feedstocks from the two quantities, where processing such volumes would cause any source to exceed any Air District Permit to Operate limit. Equation 7 below shows the calculation of the refinery peak processing volume.

$$\begin{aligned}&\text{Refinery Peak Processing Volume (thousand barrels)} = \qquad \textbf{Eqn. (7)}\\ &\quad \textit{NPDES Crude Volume} + \textit{Highest Actual Non-crude Oil Feedstock Volume}_{(2013-2015)}\\ &\quad - \textit{Volume of Crude or Non-Crude that results in Air District Permit exceedances}\end{aligned}$$

The refinery peak processing volume is intended to represent a realistic estimate of the crude and non-crude processing capabilities for each refinery, based on publicly available data documenting their past performance.

D. Carbon Intensity and Annual GHG Emissions Limits

As discussed previously, Draft Rule 13-1 sets carbon intensity limits for each Bay Area refinery. Refinery annual GHG emission limits are also provided in the draft rule as an alternate compliance option. This section discusses the calculation methodology for

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[7] Available at: http://waterboards.ca.gov/sanfranciscobay/board_decisions/adopted_orders_db/index.php See Appendix A of this document for a table of throughput values from current and recent permits.

these limits.

1. Carbon Intensity Limit

Draft Rule 13-1 defines the carbon intensity of a refinery for a given year as the ratio of the *Total Refinery GHG Emissions* for that calendar year to the *Refinery Throughput* processed in the same period, as shown in Equation 8 below. The Data Gathering section explains how these terms will be obtained, including the sources of the data used in their calculations (shown in Equations 5 and 6).

$$\text{Carbon Intensity } (\text{MTCO}_2\text{e/ thousand barrels}) = \frac{Total\ Refinery\ GHG\ Emissions}{Refinery\ Throughput} \qquad \textbf{Eqn. (8)}$$

The annual determination of carbon intensity for each refinery will be based on a three-year average, as described below.

a. Three-Year Rolling Average Carbon Intensity

Draft Rule 13-1 will require refineries to calculate a three-year rolling average carbon intensity for every calendar year. In this calculation, the carbon intensities for the previous three years are averaged (e.g., the Three-Year Rolling Average Carbon Intensity for year 2018 is the average of the carbon intensities for 2016, 2017 and 2018).

$$\text{Three-year Rolling Average Carbon Intensity } (\text{MTCO}_2\text{e/ thousand barrels}) = \frac{Carbon\ Intensity_{previous\ year} + Carbon\ Intensity_{2\ years\ ago} + Carbon\ Intensity_{3\ years\ ago}}{3} \qquad \textbf{Eqn. (9)}$$

b. Baseline Carbon Intensity

The baseline carbon intensity for each Bay Area refinery will be calculated in the same manner as the *Three-Year Rolling Average Carbon Intensity*, but for the baseline period years of 2013, 2014, and 2015.

$$\text{Baseline Carbon Intensity } (\text{MTCO}_2\text{e/ thousand barrels}) = \frac{Carbon\ Intensity_{2013} + Carbon\ Intensity_{2014} + Carbon\ Intensity_{2015}}{3} \qquad \textbf{Eqn. (10)}$$

Using a three-year average for both the annual carbon intensity calculations and the baseline carbon intensity provides consistency when comparing both quantities for the purposes of compliance determination.

If any of the baseline years represented abnormal operations for a refinery, Draft Rule 13-1 requires the substitution of that year with an alternate year that reflects normal operations. Abnormal operation years are defined in the draft rule as a calendar year where the volume of crude oil processed is less than 70% of the crude volume processed in either of the two other years.

c. Adjusted Baseline Carbon Intensity Limit

The carbon intensity limit for each refinery will be calculated by adjusting the baseline carbon intensity to account for expected GHG emissions reductions from feasible and cost-savings energy improvement projects that were not implemented during the baseline period (2013 – 2015). For this purpose, the Air District will consider any energy improvement project with a simple payback[8] of 10 years or less to be a feasible and cost-savings project. The intent of including these adjustments in the carbon intensity limit is to incentivize the implementation of these projects.

At this time, Air District staff will only consider energy improvement projects submitted by the refineries in response to CARB's Regulation for Energy Efficiency and Co-Benefits Assessment of Large Industrial Facilities in 2011 (EEA regulation). In 2013, CARB published a public report summarizing the data provided by refineries subject to the EEA regulation [5]. However, estimated GHG reductions and costs are aggregated (or not given) in the report to protect confidential business information, per CARB regulation. Air District staff will use the expected GHG emissions benefits from unrealized energy improvement (EI) projects, as obtained from confidential EEA regulation data reports, to adjust the baseline carbon intensity.

The Adjusted Baseline Carbon Intensity Limit for each Bay Area refinery will be calculated using the following equation:

$$\text{Adjusted Baseline Carbon Intensity Limit (MT CO}_2\text{e/ thousand barrels)} = \qquad \textbf{Eqn. (11)}$$

$$\frac{1}{3} * \left\{ \left[\frac{Total\ Refinery\ GHG\ Emissions_{2013} - Unrealized\ GHG\ EI\ Benefits_{2013}}{Refinery\ Throughput_{2013}} \right] \right.$$

$$+ \left[\frac{Total\ Refinery\ GHG\ Emissions_{2014} - Unrealized\ GHG\ EI\ Benefits_{2014}}{Refinery\ Throughput_{2014}} \right]$$

$$\left. + \left[\frac{Total\ Refinery\ GHG\ Emissions_{2015} - Unrealized\ GHG\ EI\ Benefits_{2015}}{Refinery\ Throughput_{2015}} \right] \right\}$$

where the Total Refinery GHG Emissions will be calculated using Equation 5, and the Refinery Throughput will be calculated using Equation 6.

Preliminary Adjusted Baseline Carbon Intensity Limits were calculated for each refinery, using CARB GHG emissions for refineries and support facilities, and reasonable estimates of crude and non-crude oil throughput (see Table 3). No adjustments have

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[8] The payback period is the length of time required to recover the cost of an investment. The payback period of a given investment or project is an important determinant of whether to undertake the position or project, as longer payback periods are typically not desirable for investment positions. The payback period ignores the time value of money, unlike other methods of capital budgeting, such as net present value, internal rate of return or discounted cash flow.

been made for net import of power, hydrogen or steam from external entities. Final values will be calculated once all the information can be collected through the rule.

Crude throughput estimates are based on 90% utilization of each refinery's nameplate crude capacity found on the United States Energy Information Administration website[9]. No non-crude oil feedstocks are included for typical refinery operations, except one refinery that receives pipeline shipments of gas oil regularly.

Table 3: Preliminary Adjusted Baseline Carbon Intensity Limits for Each Refinery

Facility	Air District Plant ID	Adjusted Baseline Carbon Intensity Limit ($MT\ CO_2e$ / thousand barrels feedstock)
Chevron	10	53
Shell	11	84
Valero	12626	58
Tesoro	14628	49
Phillips 66	21359	55

2. Annual GHG Emissions Limit

Refineries have the option to comply with a different limit, based on mass emissions of GHGs. This alternate compliance option is provided to avoid a situation where refineries are out of compliance with the carbon intensity limit yet are producing substantially less GHG emissions on a mass basis. This possibility is due to the relationship between carbon intensity and the volume of crude oil processed. Generally, carbon intensity improves with higher crude throughput. Refining crude requires a minimum amount of energy regardless of production volume. Every additional barrel of crude processed only adds an incremental amount of energy. Thus, the last barrels of crude will be much more efficient to produce, reducing the average carbon intensity of the process. However, refinery production is greatly influenced by demand for transportation fuels and other external factors outside the control of refineries. Though lower production levels would lead to lower overall GHG emissions (a desirable outcome), these levels may result in a higher carbon intensity that could cause the refinery to be non-compliant with the carbon intensity level. The annual GHG emissions limit is included as an alternate compliance option to address this situation.

The Annual GHG emissions limit for each Bay Area refinery will be calculated as the *Adjusted Baseline Carbon Intensity Limit* multiplied by the *Refinery Peak Processing Volume*, as shows in Equation 12.

$$\text{Annual GHG Emissions Limit } (\text{MT } \text{CO}_2\text{e}) = \textit{Adjusted Baseline Carbon Intensity Limit} * \textit{Refinery Peak Processing Volume} \quad \textbf{Eqn. (12)}$$

[9] https://www.eia.gov/petroleum/refinerycapacity/table5.pdf

The Adjusted Baseline Carbon Intensity Limit will be calculated using Equation 11. The Refinery Peak Processing Volume will be calculated using Equation 7.

Preliminary Annual GHG Emissions Limits were calculated for each refinery, using available information for peak crude throughput (see Table 4). Final values will be calculated once all the information can be collected through Rule 12-15 and Rule 13-1.

Table 4: Preliminary Annual GHG Emission Limits for Each Refinery

Facility	Air District Plant ID	Annual GHG Emissions Limit ($MT\ CO_2e$)
Chevron	10	4.7 Million
Shell	11	4.6 Million
Valero	12626	2.9 Million
Tesoro	14628	2.7 Million
Phillips 66	21359	2.4 Million

Annual GHG Emission Limits for the five Bay Area refineries is estimated to total 17.3 Million Metric Tons of CO_2e. Staff estimates of the Carbon Intensity and Annual GHG Emissions Limit are affected by the crude throughput and non-crude oil feedstock assumptions. These assumptions can bias the estimated Carbon Intensity and the Annual GHG Emission Limits either high or low. Final values will be calculated once all the information can be collected through Rule 12-15 and Rule 13-1.

E. Annual Determination of Compliance

Bay Area petroleum refineries are in compliance if they meet either of two limits in Draft Rule 13-1: either Adjusted *Baseline Carbon Intensity Limit* or an *Annual GHG Emissions Limit.* For a given year, a refinery is considered in compliance with Draft Rule 13-1 if:

- its *Three-Year Rolling Average Carbon Intensity* for that year is less than its *Adjusted Baseline Carbon Intensity Limit,* <u>or</u>
- its *Total Refinery GHG Emissions* for that year are less than its *Annual GHG Emissions Limit*

These limits are expected to be effective on January 1, 2018. Any refinery that fails to comply with Draft Rule 13-1 will be required to investigate the causes of excessive GHG emissions, and propose corrective actions. A second, and each subsequent calendar year with non-compliance of either limit in any five-year period shall be a violation of the rule.

IV. RULE DEVELOPMENT / PUBLIC CONSULTATION PROCESS

The publication of this document is intended to support the initial public comment portion of the development of Rule 13-1. Key milestones dates for the rest of the process are as follows:

March 27, 2017	Workshop in Cupertino
March 28, 2017	Workshop in Benicia
March 29, 2017	Workshop in Hayward
March 30, 2017	Workshop in Richmond
April 21, 2017	Comment deadline for draft rule and workshop report
July 14, 2017	Final rule, staff report, and draft CEQA document published for comment
August 13, 2017	Comment deadline for final rule, staff report and draft EIR
September 20, 2017	Board consideration of final rule

Further information on workshops and associated documents will be available on the Regulatory Workshops page on the Air District website: http://www.baaqmd.gov/rules-and-compliance/rule-development/regulatory-workshops

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