BAY AREA AIR QUALITY MANAGEMENT DISTRICT

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

STAFF REPORT

March 2017

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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 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 arbitrary and capricious by a Court. Staff's analysis also indicates that 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 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. 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 the burning of 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 draft staff report is a summary and explanation of Rule 12-16. The report will be published along with the draft 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:

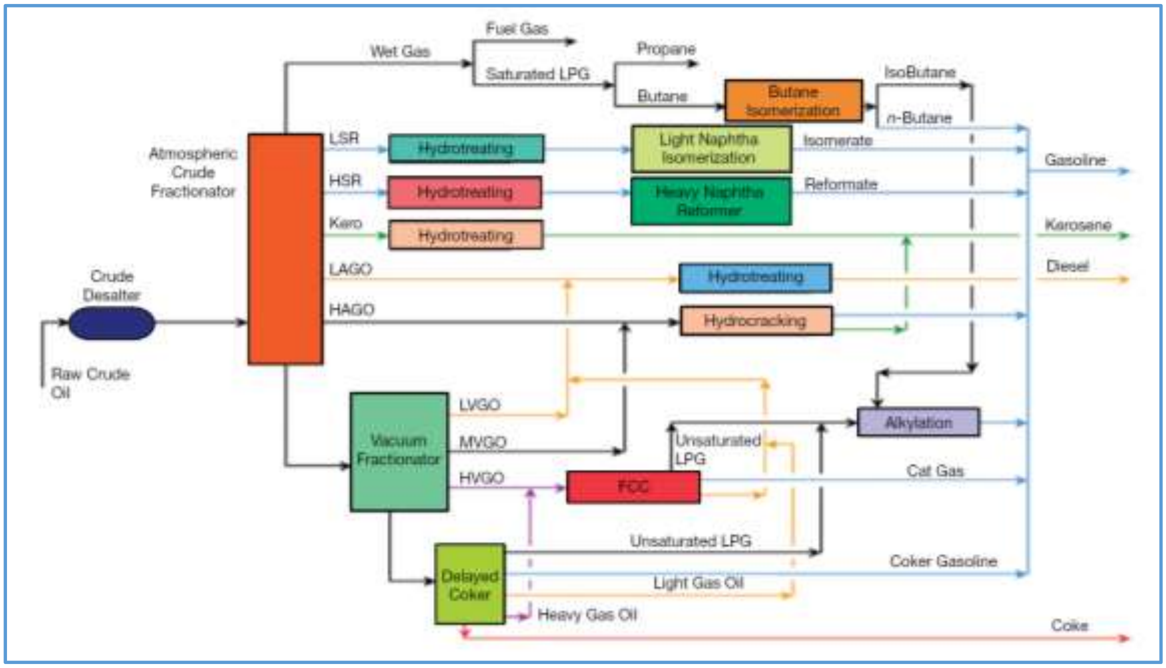
1. Air Products and Chemicals hydrogen plant, Martinez (BAAQMD Plant #10295)
2. Air Liquide hydrogen plant, Rodeo (BAAQMD Plant #17419)
3. Martinez Cogen, L.P. (BAAQMD Plant #1820)

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 in 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.

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 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 $PM_{2.5}$; 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 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%**

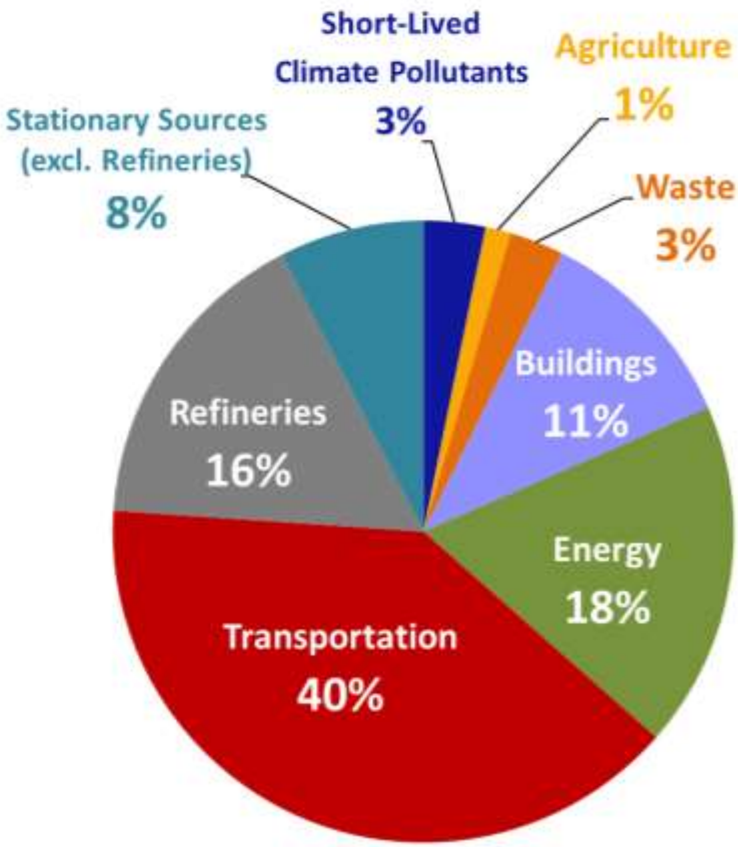
Table 2: Emissions of Relevant Pollutants by Source Category for Contra Costa and Solano Counties

Source Category	Emissions							
	$PM_{2.5}$		Anthropogenic ROG		NO_X		SO_2	
	(tons/yr.)	%	(tons/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 is 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. 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.

[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	1.28 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

5. <u>SULFUR DIOXIDE</u>

- 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.

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.

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	
Oxidation Pond	Surface area	

Refinery Equipment	Emission Point	Pollutants
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 from affected facilities.

V. ECONOMIC IMPACTS

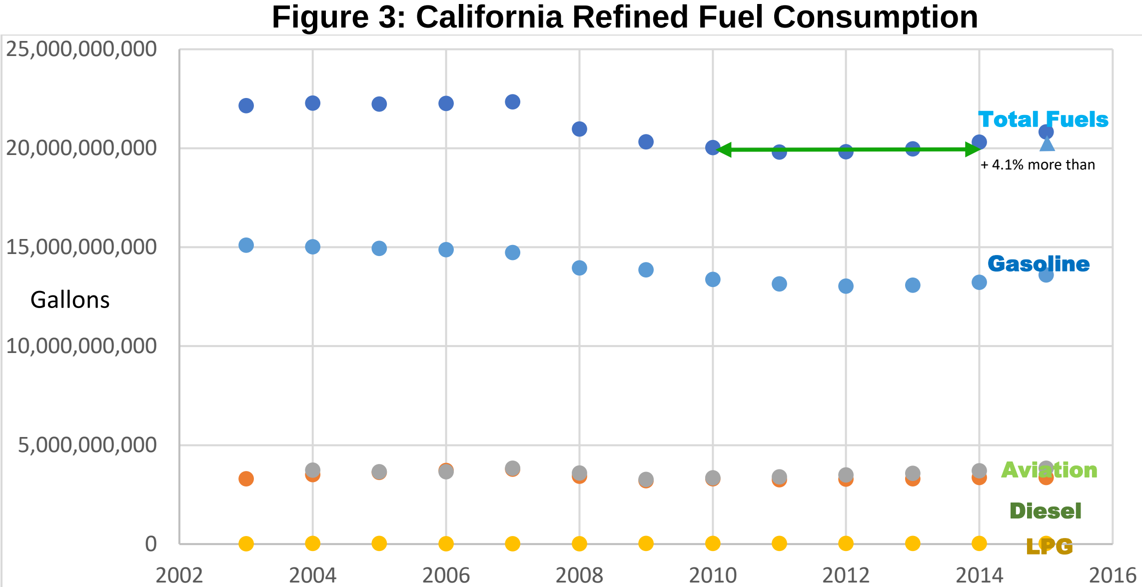
The California Health and Safety Code generally requires two different economic analyses for regulations planned and proposed by an air district. The first (H&S Code §40728.5) is a socioeconomic analysis of the adverse impacts of compliance with the proposed regulation on affected industries and business. 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 in order 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).

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.

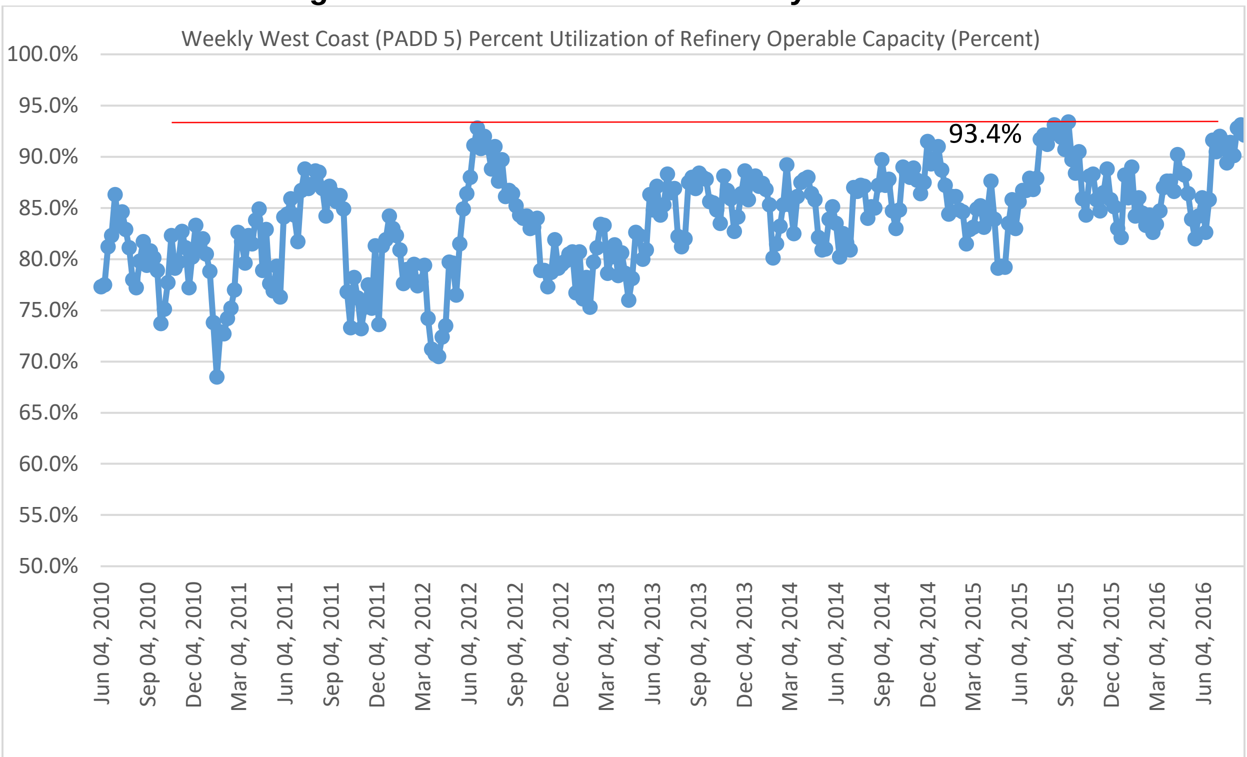
Staff also analyzed refinery operating utilization from the U.S. Energy Information Administration during the five-year baseline period from 2010 – 2014. This information is displayed on Figure 4, and is summarized in the Table 4 below:

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	92.0
2013	83.4	88.6
2014	85.8	91.5
2015	86.5	93.4
2016 ytd	87.3	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 in an effort 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.

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

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%

2016 YTD has been the highest PADD 5 utilization observed 87.3 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.

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 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 similar to 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. The economic and environmental impacts of this response depend upon future demand for transportation fuels. 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

[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.

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, $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.

[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.

Section 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

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 as a result 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 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.

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) particularly 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

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

inventory approximations. This would likely be viewed by a court as arbitrary and capricious. This is particularly so 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 $PM_{2.5}$

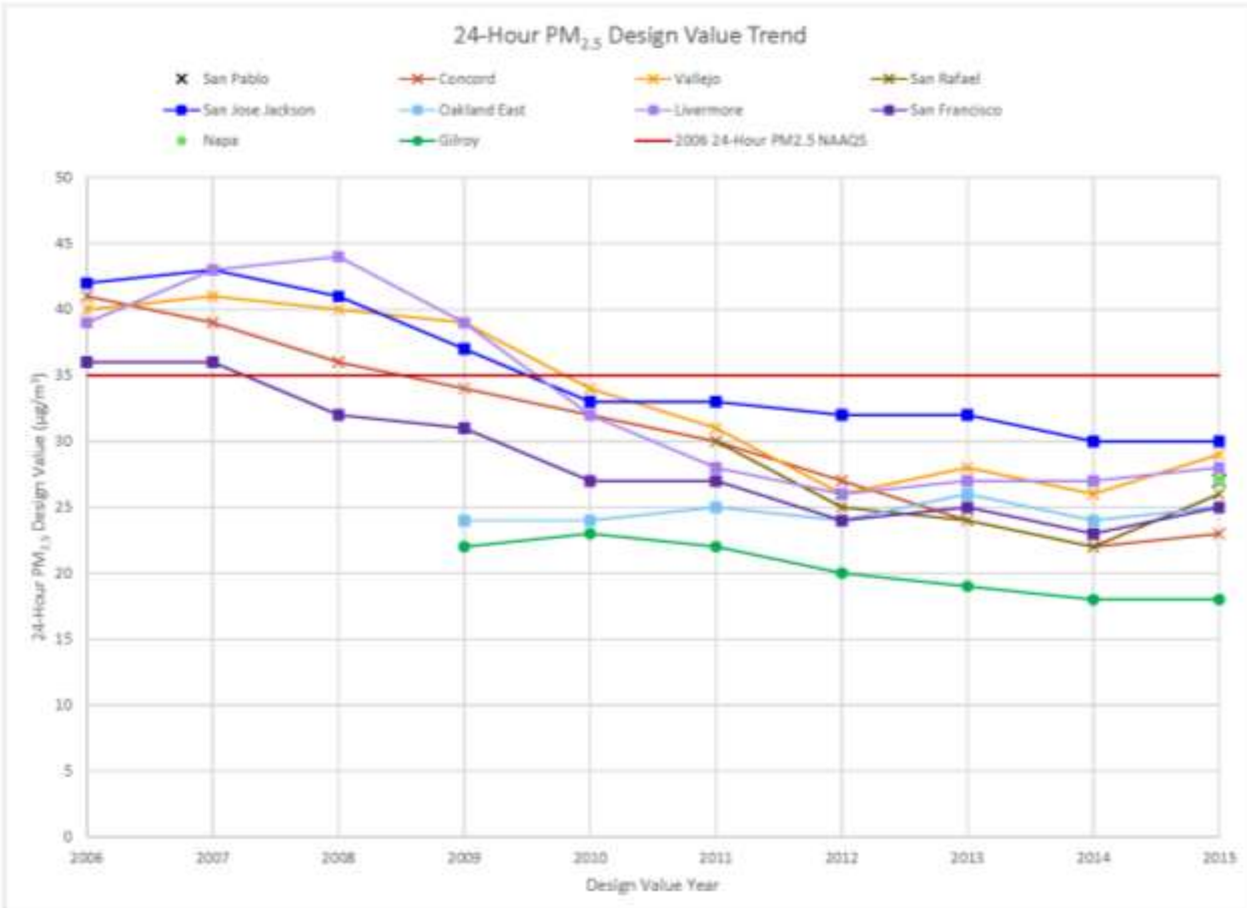

Figure 5: Ten years of 24-Hour $PM_{2.5}$ design values at Bay Area monitoring stations. The design value for 24-hour $PM_{2.5}$ is the three-year average of the 98th percentile of daily values. The Design Value Year is the last year of the three-year average. Source: US EPA's Air Quality Systems (AQS) 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, especially 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 17, 2017	Public Hearing - Board consideration of final rules