BAY AREA
AIR QUALITY
MANAGEMENT
DISTRICT

APPENDIX D

Socioeconomic Impact Analysis

April, 2022

Socioeconomic Impact Analysis of Proposed Regulation 13, Climate Pollutants: Rule 5, Industrial Hydrogen Plants

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Bay Area Air Quality Management District

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APPLIED DEVELOPMENT ECONOMICS

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1. INTRODUCTION

The Bay Area Air Quality Management District (BAAQMD or Air District) is proposing a new rule, Regulation 13: Climate Pollutants, Rule 5: Industrial Hydrogen Plants (Rule 13-5). Proposed Rule 13-5 would limit vented emissions of total organic compounds from hydrogen production and hydrogen carrying and delivery systems. Total organic compounds as proposed in Rule 13-5 are defined to include organic compounds and methane. Currently, nearly all hydrogen production plants in the Bay Area operate integrally or in support of petroleum refinery operations; however, if demand for hydrogen increases to fuel vehicles among other purposes, more stand-alone hydrogen facilities may be required. Proposed Rule 13-5 seeks to control emissions from all hydrogen production plants that utilize steam-methane reformation, as this process can result in venting of methane and other organic compounds.

The State of California made the reduction of greenhouse gas (GHG) emissions a priority, adopting Senate Bill 32, which mandated a greenhouse gas emissions reduction target of 40 percent below 1990 emission levels by 2030. In addition, Senate Bill 605 and Senate Bill 1383 require the California Air Resources Board (CARB) to approve and implement a plan by January 2018 to achieve GHG reductions. Pursuant to this legislation, the CARB subsequently developed the Short-Lived Climate Pollutant Reduction Strategy, adopted in March 2017.

Further, the Air District has a policy goal of reducing Bay Area greenhouse gas emissions to 40 percent below 1990 levels by 2030, and 80 percent below 1990 levels by 2050. Methane is a potent and short-lived climate pollutant; its global warming potential is 86 times greater than that of carbon dioxide (CO_2), when compared on a 20-year time horizon and 34 times that of CO_2 on a 100-year time horizon.[1,2] Methane represents the second largest emissions of greenhouse gases in the region, after carbon dioxide. Reducing emissions of short-lived climate pollutants, including methane, can have a dramatic effect on climate change in the near term as their atmospheric lifetime is much less than longer-lived greenhouse gasses, such as carbon dioxide. Given the importance of controlling methane, the Air District developed a comprehensive Basin-wide Methane Strategy as part of its 2017 Clean Air Plan. Proposed Rule 13-5 would be one of the first rules developed as part of this Strategy. Other source-specific methane rules are under development to address emissions from additional source-specific operations.

Petroleum refineries are a large source of methane emissions in the Bay Area. Proposed Rule 13-5 would address one of the largest sources of methane emissions from Bay Area petroleum refineries—hydrogen production plants and systems. There are currently nine permitted industrial hydrogen plants associated with five petroleum refineries within the Air District's jurisdiction. Industrial hydrogen plants vent hydrogen gas that can contain methane and other hydrocarbons under a variety

[1] Based on the 20-year global warming potential reported for methane in the Intergovernmental Panel on Climate Change Fifth Assessment Report.
[2] Unless otherwise stated, this report uses the 20-year global warming potential GWP of 86 when calculating the carbon dioxide equivalent of methane emissions since the emission reduction actions being considered are within that time frame.

of circumstances including normal operating conditions as well as startups, shutdowns, malfunctions, upsets and emergencies.

The intent of Proposed Rule 13-5 is to minimize the combination of both methane (a GHG) and other organic compound emissions which is defined as “total organic compound” emissions. The reduction in total organic compound emissions would be achieved by providing hydrogen system operators the flexibility to use any gas control technology that is appropriate for minimizing total organic compound emissions in accordance with the requirements in Proposed Rule 13-5. Typically, hydrogen plant operations either capture and reuse hydrogen gases containing methane and other constituents, including organic compounds, for incorporation into refinery gas fuel systems or they use flares to burn the mixture of hydrogen gas, methane, and other constituents. Capturing hydrogen and other gases and reusing them in the refinery system could control total organic compound emissions up to 100 percent; routing these gases to an abatement device would result in a lower control efficiency. The proposed Rule includes an Alternative Methane and Greenhouse Gas Emissions Standard Option (Alternative Standard) whereby emissions of methane are required to be controlled to 90 percent. In the case that this option is utilized, organic compounds would continue to be subject to emissions standards in Air District Regulation 8: Organic Compounds, Rule 2, Miscellaneous Operations (Rule 8-2). Installation of a flare to control total organic compound emissions is one potential compliance option. Hydrogen gases containing total organic compounds routed directly to a flare would have to meet a 98 percent control efficiency to comply with federal standards for refinery flares.

After this introduction, this report discusses in greater detail proposed Rule 13-5 (Section Two). After that discussion, the report describes the socioeconomic impact analysis methodology and data sources (Section Three). The report describes population and economic trends in the nine-county San Francisco Bay Area (Section Four), which serves as a backdrop against which the Air District is contemplating the rule. Finally, the socioeconomic impacts stemming from the proposed rule changes are discussed in Section Five. The report is prepared pursuant to Section 40728.5 of the California Health and Safety Code, which requires an assessment of socioeconomic impacts of proposed air quality rules. The findings in this report can assist Air District staff in understanding the socioeconomic impacts of the proposed requirements and can assist staff in preparing a refined version of the rule.

2. BACKGROUND AND OVERVIEW OF PROPOSED RULE 13-5

INTRODUCTION

Proposed Rule 13-5 is being developed to reduce methane, as well as other organic compound and toxic air contaminant, emissions from industrial hydrogen plants. Methane and organic compound emissions would therefore be minimized during the production of hydrogen and the distribution of hydrogen to various refinery process units.

Proposed Rule 13-5 would apply to industrial hydrogen plants using the steam-methane reformation process to produce hydrogen. This is the case for all the current industrial hydrogen plants servicing refineries, including third-party operators that produce hydrogen in hydrogen plants. Recently, Air Products, a third-party operator, purchased two hydrogen plants from PBF Energy, a petroleum company that recently purchased the Shell petroleum refinery in the City of Martinez. Therefore, the PBF refinery will be the only Bay Area refinery that does not own and operate at least one industrial hydrogen plant.

Facility owner/operators that are subject to Rule 13-5 with respect to non-methane organic compounds will be exempt from overlapping requirements from other Air District regulations, such as Rule 8-2 as discussed below.

Upon adoption of Proposed Rule 13-5 the owner or operator of an existing industrial hydrogen plant not already in compliance with the emission requirements in Rule 13-5 must apply for a permit to operate equipment to control total organic compound emissions. The owner or operator will have a total of six calendar years to design, purchase, install and operate total organic compound control equipment to comply with the requirements of Section 13-5-301. The proposed Rule includes an Alternative Standard in Section 13-5-303, whereby emissions of methane are required to be controlled to 90 percent (up to 20 percent of the total emission reductions may be GHGs other than methane substituted on a GHG equivalent mass basis). In the case that this option is utilized, an owner or operator would still be subject to the organic compound emissions standards in Air District Regulation 8: Organic Compounds, Rule 2, Miscellaneous Operations (Rule 8-2).

Proposed Rule 13-5 includes reporting requirements for owners or operators to notify the Air District of hydrogen plant atmospheric venting occurrences when total organic compound emissions exceed 15 pounds per day and the concentrations exceed 300 ppmv measured as methane on a dry basis.

The operator of an industrial hydrogen plant subject to the proposed rule would have to monitor and record all parameters necessary to demonstrate compliance with the provisions contained in the standards section of Proposed Rule 13-5. Hydrogen plant atmospheric vents would be required to have flowrate meters installed. Operators of hydrogen plant deaerator vents and carbon dioxide scrubbing vents would have to install flowrate meters, recorders, sampling ports and must monitor total organic compound emissions. Because atmospheric venting from a pressure swing absorption unit that is properly maintained and operated should never exceed the total organic compound emission standards in Section 300 of Rule 13-5, the owner or operator of a hydrogen plant with a pressure swing absorption vent would not be required to maintain emission records from the pressure swing absorption vent unless the unit malfunctions, which would likely lead to an exceedance of the emissions standards in Section 13-5-300.

REFINERY HYDROGEN USE

Hydrogen, the most abundant substance in the universe, is a colorless, odorless, tasteless and non-toxic gas at standard temperature and pressure (normal conditions). Hydrogen gas is highly flammable, is considered to be an energy carrier — similar to electricity and natural gas — and is used in an extensive range of industrial applications. While this report references the production and consumption of hydrogen at petroleum refineries, the purpose of this Rule is to reduce the methane, as well as other organic compounds, emissions that is often a component of the hydrogen gas stream vented to atmosphere under various operational conditions. For example, venting may occur during normal operational conditions or during startups and shutdowns. Reducing hydrogen gas emissions results in the reduction of methane and other emissions.

In the petroleum refining industry, hydrogen is used extensively in the processing of crude oil into refined fuels such as gasoline and diesel. Hydrogen is consumed in desulfurization units to remove contaminants from fuels and feedstocks. Additionally, hydrogen is used in the refinery fuel system. As petroleum refinery product specifications become more stringent to meet environmental requirements, refinery demand for hydrogen has continually increased to supply the refinery hydrogen consumers (process units). The two primary hydrogen consumers at Bay Area petroleum refineries are process units known as hydrotreating and hydrocracking.

EMISSION CONTROL METHODS

Because vented methane emissions from industrial hydrogen plants are not currently subject to emission limits, such emissions are usually uncontrolled unless the methane is a constituent of a gaseous stream that includes other air pollutants, such as volatile organic compounds, subject to emission limit requirements of other Air District regulations. However, not all volatile organic compound abatement technology will capture or control methane emissions. For example, activated carbon is commonly used to extract volatile organic compounds from gaseous streams via an adsorption process that traps volatile organic compound molecules onto the surface of carbon molecules while the remainder of the gaseous stream continues to flow through the carbon bed. However, methane is not typically captured by activated carbon so it flows through unabated.

One example of control technology that reduces methane as a co-benefit of reducing other air contaminants is a flare. Refinery flares are primarily used as a safety device, not as control devices to reduce refinery gases that often may include a mixture of gases including volatile organic compounds, toxic air contaminants, oxides of nitrogen, sulfur oxides and methane. Nevertheless, one Bay Area refinery and one third-party operator use flares dedicated specifically to control hydrogen gas emissions, and thus, methane emissions and any associated organic compound emissions. These particular types of flares destroy total organic compound emissions at a minimum 98 percent control efficiency.

Thermal oxidizers are another example of control technology used to thermally destroy industrial vapor streams. They are commonly used in refineries and chemical plants to control hydrocarbon-based vapors. Typically, thermal oxidizers are available in four different types depending on a variety of operational factors. They include direct-fired, recuperative, catalytic and regenerative thermal oxidizers. Thermal oxidizers can be used for planned atmospheric venting occurrences such as startups and some shutdowns; however, they generally cannot be used for unplanned events such as malfunctions and emergencies.

A third method of controlling total organic compound emissions already employed at two local refineries is the use of a closed loop system, via flare headers, that captures hydrogen system gas streams, sometimes vented at other refineries, and reintroduces the captured gas into the refinery's fuel gas system. Only a small amount of captured total organic compound gas is vented to atmosphere because the gas recovery system only sends recovered gas to the flare for combustion for safety-related reasons such as malfunctions, unplanned shutdowns, upsets and trips in the refinery system. The balance of captured gas is used in the gas recovery system. Less than two percent of flare header gas is emitted to the atmosphere post combustion. Flare headers, a collection system for refinery waste vapor streams, contains a mixture of refinery gases, including hydrogen gas.

Although not technically considered a control technology, use of pressure swing adsorption can significantly reduce methane and other organic compound emissions. Pressure swing adsorption purification is a method of separating one or more gas species from a gaseous stream containing additional (desirable) gas species. Pressure swing adsorption is used in hydrogen production as a final purification step to separate hydrogen gas molecules from other (impure) gas molecules, such as methane, carbon monoxide and carbon dioxide. Under continuous pressure, an adsorbent material targets gas with dissimilar adsorption properties as an effective way of extracting very pure hydrogen. Tail-gas, a byproduct of the pressure swing adsorption process containing the removed impurities, can then be sent back to the steam methane reformer as fuel for the steam methane reforming process. Normally, pressure swing adsorption purification removes methane molecules from the hydrogen gas stream only at the back end of the steam methane reforming process unit. Atmospheric venting prior to the pressure swing adsorption step contains methane and other air contaminants.

There are several other means of process control that may be employed collectively or in conjunction with those described above to comply with the Alternative Standard included in Rule 13-5. One facility operator has proposed installation of smaller control valves for atmospheric vents and improved process control as a means of decreasing the volume of releases and improved response time to reduce production rates when a hydrogen gas imbalance occurs. Another facility with multiple hydrogen plants that produce hydrogen of varying purity has proposed a prioritization scheme so that only the purest hydrogen is vented to the atmosphere while routing the remaining hydrogen vent gas to the existing refinery fuel gas system and hydrogen flare ring, thereby reducing excess methane emissions.

3. METHODOLOGY

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

This report relies heavily on the most current data available from a variety of sources, including Corporate reports filed with the Securities Exchange Commission (SEC), data from the US Census County Business Patterns and Census of Manufactures, the US Internal Revenue Service, and reports published by the California Energy Commission (CEC) that track gasoline prices and cost components as well as refinery production levels. ADE also utilized employment data from the California Employment Development Department – Labor Market Information Division (EDD LMID).

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

When analyzing the socioeconomic impacts of proposed new rules and amendments, ADE attempts to work closely within the parameters of accepted methodologies discussed in a 1995 California Air Resources Board (ARB) report called "Development of a Methodology to Assess the Economic Impact Required by SB 513/AB 969" (by Peter Berck, PhD, UC Berkeley Department of Agricultural and Resources Economics, Contract No. 93-314, August 1995). The author of this report reviewed a methodology to assess the impact that California Environmental Protection Agency proposed regulations would have on the ability of California businesses to compete. The ARB has incorporated the methodologies described in this report in its own assessment of socioeconomic impacts of rules generated by the ARB. One methodology relates to determining a level above or below which a rule and its associated costs is deemed to have significant impacts. When analyzing the degree to which its rules are significant or insignificant, the ARB employs a threshold of significance that ADE follows. Berck reviewed the threshold in his analysis and wrote, "The Air Resources Board's (ARB) use of a 10 percent change in [Return on Equity] ROE (i.e., a change in ROE from 10 percent to a ROE of 9 percent) as a threshold for a finding of no significant, adverse impact on either competitiveness or jobs seems reasonable or even conservative."

4. ECONOMIC AND DEMOGRAPHIC TRENDS

This section of the report discusses the larger context within which the Air District is contemplating Proposed Rule 13-5. This section begins with a broad overview of demographic and economic trends, with discussion then narrowing to industries and sources affected by the proposed rule.

REGIONAL POPULATION TRENDS

Table 1 tracks population growth in the nine-county San Francisco Bay Area between 2008 and 2021, including data for the year 2015. Between 2008 and 2015, the region grew by 0.6 per year, compared to 0.3 percent for the state as a whole. Since 2015, the Bay Area region has had a lower growth rate than the state. Overall, there are 7,703,016 people in the region. At 1,934,171, Santa Clara County has the most people, while Napa has the least, at 137,637. Contra Costa grew the fastest between 2008 and 2021, at 0.7 percent a year, while Marin and Sonoma lost population.

Table 1: Population Trends: Bay Area Counties, Region, and California, 2008-2021

Jurisdiction	2008	2015	2021	08-15 CAGR	15-21 CAGR	08-21 CAGR
California	38,292,687	39,131,307	39,782,870	0.3%	0.3%	0.3%
SF Bay Area	7,375,678	7,671,279	7,703,016	0.6%	0.1%	0.3%
Alameda	1,556,657	1,632,599	1,656,591	0.7%	0.2%	0.5%
Contra Costa	1,060,435	1,128,405	1,153,854	0.9%	0.4%	0.7%
Marin	258,618	263,327	257,774	0.3%	-0.4%	0.0%
Napa	137,571	141,607	137,637	0.4%	-0.5%	0.0%
San Francisco	845,559	872,723	875,010	0.5%	0.0%	0.3%
San Mateo	745,858	767,921	765,245	0.4%	-0.1%	0.2%
Santa Clara	1,857,621	1,931,565	1,934,171	0.6%	0.0%	0.3%
Solano	426,729	430,530	438,527	0.1%	0.3%	0.2%
Sonoma	486,630	502,602	484,207	0.5%	-0.6%	0.0%

REGIONAL ECONOMIC TRENDS

Data in Table 2 describe the larger economic context within which officials are contemplating the Proposed Rule 13-5. Employers in the region employ 3.7 million workers. The number of jobs in the region grew annually by 1.3 percent between 2008 and 2015, the period that included the Great Recession. This was almost twice the rate of job growth statewide during this period. Since 2015, the region's job growth showed no growth, as the COVID-19 pandemic had a devastating impact on the leisure and hospitality sectors. By comparison, the state had a modest 0.2 percent job growth.

The economic sectors in Table 2 are sorted by the share of total employment in 2020. The top-five sectors in the Bay Area in terms of total number of workers are Professional and Business Services

(NAICS 54-55) (745,400 workers); Educational and Health Services (NAICS 61-62) (575,300 workers); Trade, Transportation, and Utilities (NAICS 42, 44, 45, 48, 49, & 22) (523,500 workers); Government (443,600 workers), which also includes public sector health and education jobs;; and Manufacturing (NAICS 31-33) (352,700 workers), which includes the petroleum refineries that would be subject to proposed Rule 13-5.

Table 2: San Francisco Bay Area Employment Trends By Sector: 2008 - 2020

Industry Sector		2008	2015	2020	2020 % of Total	2020 CA % of Total	SFBA CAGR* 08-15	SFBA CAGR 15-20	CA CAGR 08-15	CA CAGR 15-20
Total, All Industries		3,377,300	3,692,400	3,693,500	100.0%	100.0%	1.3%	0.0%	0.7%	0.2%
54-56	Professional and Business Services	593,200	699,300	745,400	20.2%	15.9%	2.4%	1.3%	1.5%	0.9%
61-62	Educational and Health Services	455,600	550,500	575,300	15.6%	16.2%	2.7%	0.9%	5.1%	2.2%
42, 44-45, 48-49, 22	Trade, Transportation, and Utilities	552,400	566,300	523,500	14.2%	17.6%	0.4%	-1.6%	0.4%	-0.1%
	Government	478,400	466,200	443,600	12.0%	14.7%	-0.4%	-1.0%	-0.5%	0.3%
31-33	Manufacturing	342,900	334,300	352,700	9.5%	7.7%	-0.4%	1.1%	-1.4%	-0.3%
71-72	Leisure and Hospitality	336,300	405,700	297,400	8.1%	9.1%	2.7%	-6.0%	2.2%	-4.0%
51	Information	118,100	166,000	240,100	6.5%	3.2%	5.0%	7.7%	0.4%	1.8%
11, 21, 23	Natural Resources and Construction	199,600	194,200	219,900	6.0%	7.8%	-0.4%	2.5%	-0.3%	1.8%
52-53	Financial Activities	188,100	187,400	191,600	5.2%	5.0%	-0.1%	0.4%	-0.9%	0.6%
81	Other Services	112,900	122,900	104,000	2.8%	2.8%	1.2%	-3.3%	-5.1%	-2.4%

The fastest job growth rates since 2015 have been in Information Services, which includes many internet businesses, followed by Natural Resources and Construction; Professional and Business Services; and Educational and Health Services.

The table demonstrates the advanced nature of the regional economy, as over 26 percent of all jobs are in the combined Professional, Business, and Information services categories, compared to 19.1 percent for the state. In addition, manufacturing in the Bay Area grew at an average annual rate of 1.1 percent between 2015 and 2020, while the sector declined by 0.3 percent during this period statewide. This is due in large part to the many technology-driven industries that are concentrated in that category in the Bay Area.

TRENDS FOR INDUSTRIES SUBJECT TO PROPOSED RULE 13-5

Proposed Rule 13-5 would affect petroleum refineries (NAICS 324110) of which there are five in the Bay Area. The most recent employment data available for the refineries indicates there were 3,536 workers directly employed at the facilities in 2018 (Table 3). Refinery jobs have been growing slowly since 2014, but have not recovered to the 2009 level of nearly 4,000 jobs at the beginning of the Great Recession.

Table 3: Employment Trends for Large Refineries in the San Francisco Bay Area: 2009-2018

YEAR	JOBS
2009	3,976
2010	3,622
2011	3,620
2012	3,542
2013	3,726
2014	3,269
2015	3,440
2016	3,464
2017	3,503
2018	3,536

With the recession in 2020 due to the COVID-19 pandemic, refinery production levels were affected, with associated financial impacts and job reductions at the facilities. Shelter in place orders that reduced commute and shopping travel dramatically reduced demand for gasoline. In 2021, demand for gas began increasing and gas prices also increased significantly. However, it is not clear whether there may still be longer term effects on the economics of producing refined oil products. ADE researched refinery operations during past recessions to see how this industry has been affected. In the past 20 years there have been two major recessions, in 2001 and 2009.

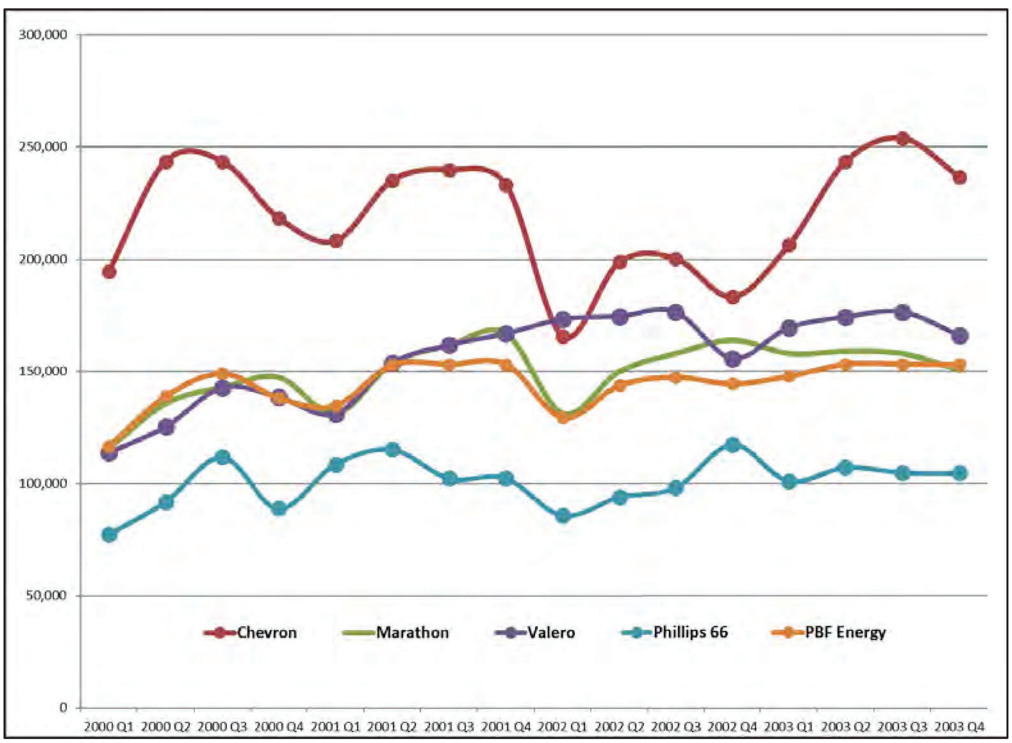
According to the National Bureau of Economic Research (NBER), the 2001 recession began in March, 2001 and was short-lived, reaching its lowest point in November 2001. On a national level, between 2000 and 2001, the number of refineries declined by 17.5 percent, from 565 to 466. The number of refineries with positive net income declined even more, by 69.8 percent, from 538 to 162. By 2002, the number of refineries began to climb back to pre-2001 totals, reaching 524 refineries. However, in 2002, net income dropped to 4.2 percent of sales, down from 8.1 percent the prior year (Table 4).

In the Bay Area, the five major refineries continued to operate, but the levels of production dipped in the first quarter of 2002 for all the refineries except Valero (Figure 1). Chevron and Valero both reduced production at the end of 2002, but by 2003 all of the refineries appear to have resumed normal production levels.

Table 4: Financial Data for US Refineries, 2000-2015

Year	Number of Returns: Total	Number of Returns: With Net Income	Total Receipts: All Returns ($Billions)	Total Receipts: Returns with Net Income ($Billions)	Net Income ($Billions)	Net Income as % of Receipts for All Returns
2000	565	538	$708.5		$62.7	8.9%
2001	466	162	$633.8	$605.1	$51.2	8.1%
2002	524	210	$669.9	$547.8	$28.4	4.2%
2003	321	33	$878.2	$762.4	$59.5	6.8%
2004	715	43	$1,233.4	$1,208.0	$101.0	8.2%
2005	1067	408	$1,586.4	$1,582.6	$136.1	8.6%
2006	928	171	$1,772.7	$1,760.2	$142.0	8.0%
2007	661	160	$1,885.8	$1,858.9	$140.0	7.4%
2008	569	150	$2,317.4	$2,272.1	$146.0	6.3%
2009	241	159	$1,467.9	$1,011.0	$103.8	7.1%
2010	246	169	$1,884.3	$1,471.1	$133.4	7.1%
2011	202	162	$2,405.5	$2,323.7	$128.1	5.3%
2012	217	159	$2,396.8	$2,113.6	$152.7	6.4%
2013	207	67	$2,202.1	$1,894.1	$123.9	5.6%
2014	203	161	$2,086.0	$1,781.3	$103.1	4.9%
2015	143	116	$1,330.0	NA	$67.0	5.0%

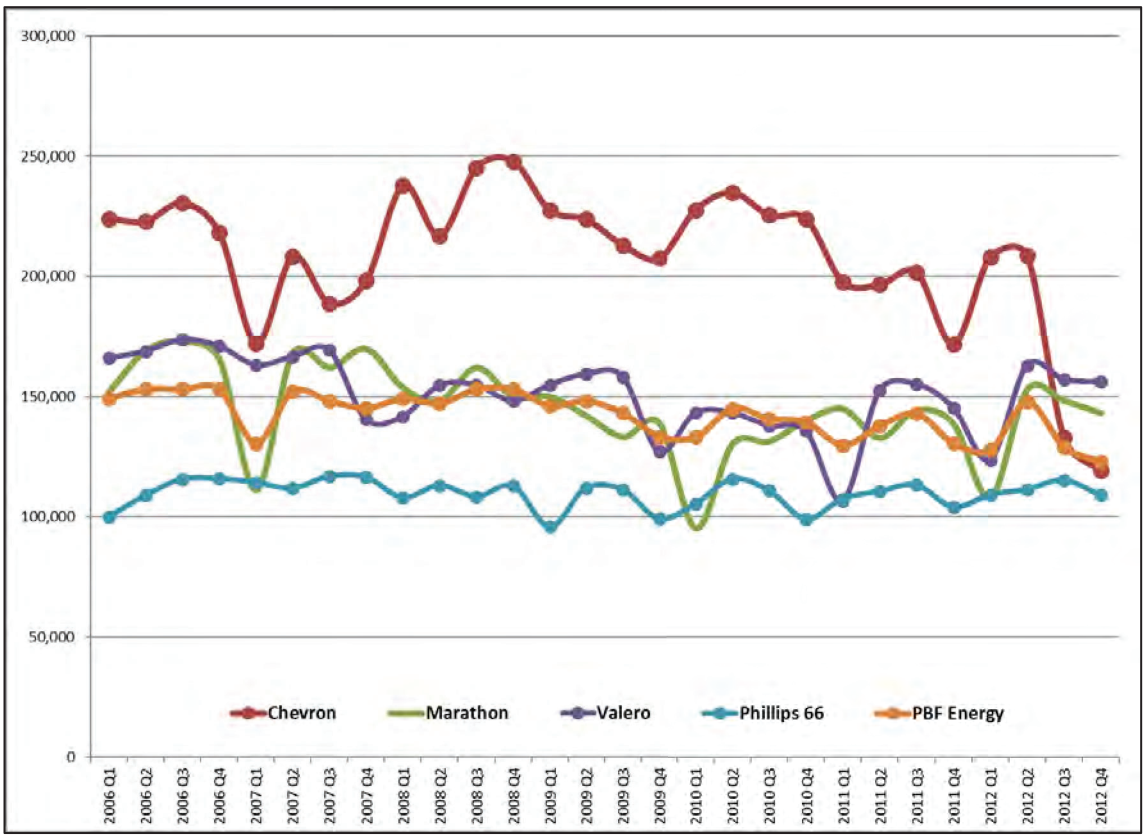
Figure 1: Bay Area Refinery Production Levels, 2001 Recession



According to the NBER, the 2008 Great Recession began officially in December 2007, and extended downward to its lowest point in June 2009. But the actual recovery after June 2009 was "flat", in contrast to the earlier 2001 recession. The full effect of the recession that began in December 2007 became evident in 2009, when there were 241 US refineries as compared to 569 in 2008, for a loss of 57.6 percent (Table 4). Average net income per refinery went from $973 million to $653 million for a 32.8 percent decline, although net income as a percent of sales did not decline as much as in 2002. In 2008 it was 6.3 percent, down from 8.0 percent in 2006. However, this figure has never again reached 8.0 percent on a national level. Also, in the years immediately prior to and including 2008, there were 928 US refineries in 2006 and 661 in 2007. Since 2009, there have consistently been less than 300.

At the Bay Area refineries, production levels had dropped at the beginning of 2007 and did not really show the effects of the recession until late 2009, with additional dips in 2012 (Figure 2).

Figure 2: Production Levels at Bay Area Refineries, 2006-2012



This historical review suggests that there have been long lasting structural changes to the refining industry from past economic downturns, combined with shifts in consumer demand from technological changes in the auto industry. Profit ratios for refineries have been declining since the Great Recession. The analysis described below suggests that for the Bay Area refineries, profit levels slipped below 3 percent by 2019. It may be expected that profits dropped further in 2020 due to the COVID-19 pandemic. It is difficult to predict the time frame for recovery from this recession, as there remains much uncertainty despite the development of COVID vaccines about the pace of when consumers and businesses will resume previous levels of economic activity. However Proposed Rule 13-5 provides a five-year period for the refineries to reach compliance. For purposes of this analysis, we use the 2019 financial performance of the refineries as a benchmark for the effects of the compliance costs in 2026.

In 2017, the US Bureau of the Census counted 18 refineries in California. In aggregate, the net income for these facilities was 4.1 percent of sales (Table 5), slightly lower than the national figure of 5.0 percent in 2015.

Table 5: Operating Characteristics for California Refineries, 2017

Operating Parameter	2017 Value
Number of firms	11
Number of establishments	18
Sales, value of shipments, or revenue ($1,000)	$56,216,881
Annual payroll ($1,000)	$1,174,919
Total fringe benefits ($1,000)	$398,409
Total cost of supplies and/or materials ($1,000)	$46,126,161
Total capital expenditures for buildings, structures, machinery, and equipment (new and used) ($1,000)	$1,709,789
Total depreciation during year ($1,000)	$1,423,320
Total rental payments or lease payments ($1,000)	$118,057
Total other operating expenses ($1,000)	$2,950,272
Net operating income	$2,315,954
Percent of sales	4.1%

Table 6 below identifies the businesses in the Bay Area that are full-scale refineries. The California Energy Commission (CEC) tracks each refinery's throughput capacity; however, for Marathon and Phillips 66 we have used projected capacities reported by the companies since these refineries are converting to new operations to produce renewable fuels. Of the five operating refineries in the region, Chevron is the largest, with the capacity to refine 245,300 42-gallon barrels of crude oil per day (BPD). The five affected sources employ approximately 3,500 workers, who make an average wage of $127,000, not including benefits, based on the data in Table 5.

The five affected sources' combined throughput capacity is approximately 646,500 barrels per day (BPD). Based on average utilization rates for refineries as provided in the US Census of Manufactures, we estimate the actual effective throughput of the refineries is about 578,000 BPD. Refined products exceeded the crude oil inputs by about 3.5 percent in 2019, resulting in an estimate of 598,200 BPD of refined products produced by the Bay Area refineries.[3]

[3] California Energy Commission, Weekly Fuels Watch, 2019.

Table 6: Bay Area Refineries (California Energy Commission) and Crude Oil Capacity

REFINERY	BARRELS PER DAY
Chevron U.S.A. Inc., Richmond Refinery	245,300
Marathon Petroleum Corp., Golden Eagle (Avon/Martinez) Refinery	47,600
PBF Energy, Martinez Refinery	156,400
Valero Benicia Refinery	145,000
Phillips 66, Rodeo San Francisco Refinery	52,200

Source: Applied Development Economics, Inc., based on California Energy Commission

All five of the refineries, plus the Air Liquide Hydrogen plant, see increased costs from implementation of Rule 13-5. For these plants, we have estimated annual sales (revenues) and profit levels, for use in analysis of the economic impacts of the rule in the next section of the report (Table 7). The Marathon refinery is not currently in operation, but has planned a conversion to renewable fuels. When it resumes operations, it will be subject to the Rule 13-5 requirements. Similarly, the Phillips 66 plant is proposed for conversion to a non-petroleum biofuels plant. However, for purposes of this analysis, we have assumed the plant would be subject to Proposed Rule 13-5 when it first becomes effective.

The effective capacities in barrels per day for each of the refineries shown in Table 7 are based on the factors described above. The revenue information is based on an estimate of the wholesale value of gasoline at $121.04, based on 2019 data provided by the CEC.[4] The net profits estimates are based on data from corporate reports for each of the petroleum companies, described further below

Chevron Richmond. In its 2019 annual report, Chevron reports $1.559 billion in earnings from its US downstream refining operations. This was down from $2.1 billion in 2018, which Chevron ascribes to lower margins on sales for refined products, but also was affected by a higher depreciation expense of $100 million following first production at the new hydrogen plant at the Richmond refinery. Chevron reported sales of 1,250 (million barrels per day) of gasoline and other refined products. We estimate, then, that Chevron earned $1,247 per barrel of refined product. This amount is applied to the output estimate in Table 7 of 226,820 barrels per day, resulting in an estimate of the net income from the Richmond refinery of $282.8 million. This is down from a 2017 estimate of $332.6 million, which was 4.1 percent of sales for that year. The current estimate is 2.8 percent of sales.

PBF Energy Martinez. PBF completed the purchase of this refinery from Shell in February 2020, so there is no 2019 operating or financial data for the refinery under PBF ownership. Consequently, we have reviewed the Shell annual report for 2019 to estimate the operating performance of the Martinez refinery (operated as Martinez Refining Company).

[4] California Energy Commission, Estimated 2019 Gasoline Price Breakdown and Margins Details.

Shell reported downstream refinery net earnings of $6.7 billion for all its refining operations, and indicates that 19 percent of its refined products sales occurred from US operations, so we have prorated net earnings to $1.27 billion for US refineries. Shell reports that total US refining capacity was 1,117,000 barrels per day, which yields a return of $1,136 per barrel of refined product, slightly below the comparable figure for Chevron.

Based on these factors, we estimate the net income from the Martinez refinery was $177.7 million, which is also lower than the 2017 estimate of $212.1 million for that facility. The 2019 net income represents 2.8 percent of estimated sales revenue.

Marathon Martinez. Marathon Petroleum Company (MPC) plans to convert its refinery to produce 730 million gallons per year of lower carbon-intensity renewable fuels, or about 47,600 barrels per day (BBL/Day).[5] The most recent data for this refinery when operated as a petroleum refinery indicated a throughput capacity of 161,500 BBL/Day. Renewable fuels have the same chemical composition as petroleum-based fuels and can be used in existing internal combustion engines. For purposes of this analysis, we use the same wholesale prices as the other refineries to estimate total sales from the new Marathon operation as well as Phillips 66 below. Currently, there are not many renewable fuels refineries in the United States and detailed operating data is not available. For this analysis, we use the average refinery profit levels as a percent of sales to evaluate the socioeconomic impacts of the proposed Rule 13-5.

Valero. In its 2019 Annual Report, Valero reports net income of $4 billion from its refining operations, on a throughput of 2.95 million barrels per day. This represents a return per BPD of $1,362, which when applied to the daily throughput of the Benicia refinery results in annual net income of $182.6 million. This is a profit rate of 3.1 percent, down from the 2017 estimate of 3.8 percent.

Phillips 66. The Rodeo plant conversion would create capacity to produce 680 million gallons annually of renewable diesel, renewable gasoline, and sustainable jet fuel. Combined with an additional project onsite that is under development, the plant would produce a total of 800 million gallons per year, or about 52,200 BPD. The most recent data for this plant as a petroleum refinery indicates that it had a capacity for 120,200 BPD.

The company's website states that, "This capital efficient investment is expected to deliver strong returns through the sale of high value products while lowering the plant's operating costs."[6] The plant is expected to employ 400 workers when operations are fully stabilized.

As discussed above for the Marathon refinery we have used average wholesale prices and net income ratios from the other refineries to estimate the financial characteristics of the planned renewable fuels plant in Rodeo.

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[5] https://www.marathonpetroleum.com/Newsroom/Company-News/Marathon-Petroleum-to-Proceed-with-Conversion-of-Martinez-Refinery-to-Renewable-Fuels-Facility/

[6] https://investor.phillips66.com/financial-information/news-releases/news-release-details/2020/Phillips-66-Plans-to-Transform-San-Francisco-Refinery-into-Worlds-Largest-Renewable-Fuels-Plant/default.aspx

Air Liquide. This facility is the largest hydrogen plant in the area. The US Census indicates that there are six establishments in the gas production industry in Contra Costa County, employing 74 workers. Nationally, firms in this industry generate nearly $670,000 in annual sales per worker employed. Using this metric and estimating 20 jobs at the plant, we estimate the Air Liquide plant generates about $13.4 million in annual sales. The national data also indicate firms in this industry enjoyed a 40 percent return on sales in 2017; however, Air Liquide reports a net income ratio of 18.1 percent for its gas operations in the western hemisphere. Using this ratio, we estimate annual profits at the Contra Costa plant at $2.4 million.

Table 7: Estimated Revenues and Net Profits for Businesses Affected by Rule 13-5

	Chevron	Marathon	PBF Energy Martinez	Valero	Phillips 66	Air Liquide
Effective Barrels Per Day	219,150	44,019	139,743	134,092	48,273	NA
Est. Revenues	$10.0 bil.	$1.9 bil.	$6.4 bil.	$5.9 bil.	$2.1 bil.	$13.4 mil.
Est. Net Profits	$282.8 mil.	$56.3 mil.	$177.7 mil.	$182.6 mil.	$21.9 mil.	9.5 mil.

5. SOCIOECONOMIC IMPACT ANALYSIS OF PROPOSED RULE 13-5

COSTS OF RULE COMPLIANCE

This section of the report analyzes socioeconomic impacts stemming from Proposed Rule 13-5. Compliance with the Rule will require emissions reductions at two refineries: Valero and PBF Energy. Air District staff has estimated costs at both these facilities to a) install a flare system, and b) to install a hydrogen plant flare gas recovery system to achieve the required emissions reductions. In both cases, the flare systems are less expensive and those costs are the ones shown in Table 8 below. The facilities have also proposed alternative emissions reduction measures that may further substantially reduce costs. However, according to Air District staff it is not clear that these measures would be sufficient to meet the required emissions reductions, so for purposes of this analysis, we have used the dedicated flare costs shown in Table 8. In addition, all of the affected facilities will need to install flow meters and sampling ports in their CO_2 and deaerator lines and perform quarterly monitoring.

Table 8: Compliance Costs by Facility for Rule 13-5

Facility	Capital Cost to Comply with Section 13-5-301	Cost to Install Flowrate Meter	Cost for Quarterly Monitoring in Deaerator/CO_2 Vents	Cost to Install Sampling Port in Deaerator/CO_2 Vents	Cost to install atmospheric vent monitoring equipment
Valero	$30,000,000 ($4,020,114 annualized)	$230,100 to $253,110 - annualized	$112,000 to $320,000 - annualized	$9,204 to $13,806 - annualized	$1,753,515 to $2,228,015 - annualized
PBF Energy	$40,000,000 ($5,284,833 annualized)	$265,500 to $292,050 - annualized	$168,000 to $480,000 - annualized	$10,620 to $15,930 - annualized	$2,023,286 to $2,570,786 - annualized
Marathon	N/A – therefore no cost	$70,800 to $77,880 - annualized	$112,000 to $320,000 - annualized	$2,832 to $4,248 - annualized	$539,543 to $685,543 - annualized
Phillips 66	N/A – therefore no cost	$17,700 to $19,470 - annualized	$28,000 to $80,000 - annualized	$708 to $1,062 - annualized	$134,886 to $171,386 - annualized
Chevron	N/A – therefore no cost	$35,400 to $38,940 - annualized	$56,000 to $160,000 - annualized	$1,416 to $2,124 - annualized	$269,772 to $342,772 - annualized
Air Liquide	N/A – therefore no cost	$17,700 to $19,470 - annualized	$28,000 to $80,000 - annualized	$708 to $1,062 - annualized	$134,886 to $171,386 - annualized
Total	$70,000,000 ($8,040,227 annualized)	$637,200 to $700,920 - annualized	$504,000 to $1,440,000 - annualized	$25,488 to $38,232 - annualized	$4,855,887 to $6,169,887 - annualized

The methodology section above explains that compliance costs that exceed ten percent of return on equity have the potential to create significant adverse socioeconomic impacts on the affected facilities. Table 9 compares the total annual costs to the estimated annual net income for the plants, from Table 7 above. The total annual compliance costs range from about $15.3 million to $17.7 million for all facilities combined. This represents 1.9 to 2.2 percent of the estimated net income of the affected facilities combined. For the Valero and PBF Energy plants which require major capital expenditures, the upper range cost estimates represent 3.7 and 4.9 percent of net income, respectively.

For the Air Liquide plant, which is a smaller facility, the annualized monitoring costs represent 7.6 to 11.3 percent of estimated net income. While the upper end of this range would exceed the 10 percent threshold of significance, this high-end estimate should be considered a worst-case scenario. In addition, Air District staff believe that most of these companies already collect the information required for the monitoring, so the actual monitoring costs may only be 20 to 30 percent of the range shown in Table 8 above.

As discussed above, the upper end cost estimate range may represent costs exceeding the 10 percent threshold of significance for the Air Liquide plant. While the high-end estimate should be considered as a worst-case scenario, the costs may be substantially lower than this estimated value. Nevertheless, the potential impacts associated with costs above the threshold of significance were estimated based on this high-end estimate. Of particular concern under the Health and Safety Code would be the potential for lost jobs at the plan to compensate for the impact to net income. At $270,000 per year, the upper end impact is about $30,000 above the 10 percent impact threshold. The average salary and benefits for workers in the gas production industry in California is $92,300.[7] The maximum cost impact exceeding the threshold, therefore, represents less than a third of the cost for one employee at Air Liquide. We conclude that it is unlikely the company would choose to reduce employment to mitigate this impact.

Also, both Valero and PBF Energy have proposed alternative emission reduction measures that would potentially replace the need for the dedicated flare gas recovery systems. Valero estimates the capital cost of the alternative reduction methods at $6 million and Marathon Refining Company (PBF Energy) estimates capital cost of the alternative measures to cost between $5 million and $10 million. While the specific measures proposed by the companies have not been approved by the Air District, there is a possibility that the ultimate costs the companies will incur will be less than shown in Table 8 and Table 9.

[7] 2019 Census of Manufactures.

Table 9: Impact of Rule 13-5 Annual Compliance Costs on Facility Net Income

Facility	Total Annual Cost ($Millions)			Annual Net Income ($Millions)	Costs as Percent of Income
Valero	$6.12	to	$6.83	$182.60	3.35% to 3.74%
PBF Energy Martinez	$7.75	to	$8.64	$177.70	4.36% to 4.86%
Marathon	$0.73	to	$1.09	$146.50	0.50% to 0.74%
Phillips 66	$0.18	to	$0.27	$22.00	0.82% to 1.24%
Chevron	$0.36	to	$0.54	$282.80	0.13% to 0.19%
Air Liquide	$0.18	to	$0.27	$2.40	7.55% to 11.33%
Total	$15.33	to	$17.65	$813.90	1.88% to 2.17%

CARBON CREDITS

An additional potential cost mitigation for refineries would be to trade carbon credits on the international markets.

The carbon credits market consists of both a voluntary market and a compliance market. The compliance market, which is represented as a cap-and-trade market, currently operates in California. California is the only state that individually operates a cap-and-trade market. The Regional Greenhouse Gas Initiative operates on the East Coast with about a dozen states participating.

Under the California Air Resources Board regulations, major sources that generate large amounts of carbon emissions can purchase carbon credits to meet emissions goals. Refineries are subject to cap-and-trade requirements. The California cap-and-trade program has 450 participants.[8] The market value of carbon credits fluctuates, but the most recent data from the Air Resources Board (ARB) indicates that the median price for a carbon credit ranged from $15.32 (offset) to $24.62 (allowance).[9] [10] Applied to the proposed reduction of 2,514 tons of methane (equivalent of 85,492 tons of carbon dioxide based on a 34 GWP for methane), this would imply a carbon credit value ranging from $1.3 (offset) million to $2.1 million (allowance). Depending on the allowable cap for each facility, the affected companies may be able to monetize a portion of their carbon reductions under this program.

Up to this point, the voluntary carbon credit markets have largely operated on a relatively informal basis. Nonetheless, the voluntary carbon credits market has steadily grown, and was projected to reach an annual market value of $1 billion for the first time in 2021, with an all-time market value of

[8] Thompson, Lucas, Leticia Miranda, and NBC News; "What are carbon credits? How fighting climate change became a billion-dollar industry"; October 30, 2021. https://www.nbcnews.com/business/business-news/are-carbon-credits-fighting-climate-change-became-billion-dollar-indus-rcna3228

[9] https://ww2.arb.ca.gov/sites/default/files/2021-11/nc-2021_q3_transfersummary.xlsx

[10] An offset carbon credit means that the greenhouse gas emission will be offset by a mitigating project, such as reforestation or agricultural projects. An allowance carbon credit functions more like a permit to emit.

$6.7 billion.[11] McKinsey projects that the market for carbon credits could grow to $50 billion around 2030.[12]

In November 2021, the United Nations convened the COP26 conference in Glasgow, which established several new international agreements on carbon reductions. One of the more significant outcomes of the conference was implementation standards for Article 6, which was established under the Paris Agreement in 2016.

Article 6 laid out international standards for trading carbon credits, and the Glasgow conference created the necessary mechanisms and rules to implement it. According to S&P Global Platts, "Article 6 is the final article to be implemented of the 29 separate articles that make up the 2015 Paris Climate Agreement and sets up the carbon crediting mechanism used by governments to meet their reduction targets under the nationally determined contributions system. Paragraph 6.4 sets the United Nations as a certifier of carbon projects that can generate credits for governments to reach these NDCs."[13] While the rules established under Article 6 largely apply to governments, the agreement promises to greatly expand the voluntary carbon credits market by boosting the credibility of carbon credit markets and establishing international standards.[14]

SOCIAL COSTS OF GREENHOUSE GASES (GHG)

Compliance with Rule 13-5 will impose costs on the affected refineries and hydrogen producers in the Bay Area. However, failure to reduce emissions of GHG imposes ongoing costs on society in terms of contributing to climate change and the long-term effects of that on a wide range of human activities and the built and natural environment. The social cost of carbon (SCC) takes a holistic view of how carbon emissions create societal impacts and uses various data measures to put a cost on it. At a simplistic level, SCC attempts to measure the economic harm caused by climate change based on the dollar value per ton of carbon dioxide (CO_2) emissions.[15]

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[11] Ecosystem Marketplace; "Voluntary Carbon Markets Rocket in 2021, On Track to Break $1B for the First Time"; September 15, 2021.
https://www.ecosystemmarketplace.com/articles/press-release-voluntary-carbon-markets-rocket-in-2021-on-track-to-break-1b-for-first-time/

[12] Favasuli, Silvia, Vandana Sebastian and S&P Global Platts; "Voluntary carbon markets: how they work, how they're priced, and who's involved"; June 10, 2021.
https://www.spglobal.com/platts/en/market-insights/blogs/energy-transition/061021-voluntary-carbon-markets-pricing-participants-trading-corsia-credits

[13] Favasuli, Silvia, and S&P Global Platts; "Paris Accord Article 6 approval set to jump-start evolution of voluntary carbon market"; November 17, 2021.
https://www.spglobal.com/platts/en/market-insights/latest-news/energy-transition/111721-paris-accord-article-6-approval-set-to-jump-start-evolution-of-voluntary-carbon-market

[14] Krukowska, Ewa, and Bloomberg Green; "COP26 Finally Sets Rules On Carbon Markets. What Does It Mean?"; November 13, 2021.
https://www.bloomberg.com/news/articles/2021-11-13/cop26-finally-set-rules-on-carbon-markets-what-does-it-mean

[15] Patton, Vickie, and Environmental Defense Fund; "The true cost of carbon pollution"; 2020.
https://www.edf.org/true-cost-carbon-pollution

The legal rationale for including SCC in socioeconomic impact studies of new regulations dates back to a 2007 court decision in which the US Court of Appeals, Ninth Circuit ruled that federal agencies needed to account for the cumulative effects of greenhouse gas emissions in cost-benefit analyses.[16]

The methodologies for quantifying SCC are highly varied. The monetary values assigned to SCC depend on several assumptions about socioeconomic forecasts (population and economic growth, and the resulting carbon emissions), climate projections (rising temperatures and sea levels compared to CO_2 levels, etc.), benefits and costs; and the discount rate (indication of rate at which society trades off present for future benefits).[17]

At the federal level, the Interagency Working Group (IWG) was formed as a result of the 2007 court decision, and has issued and updated SCC estimates since 2010. While the estimates have covered a wide range, depending on the measures used, the Biden administration announced an initial estimated SCC of about $51 per metric ton of CO_2. This figure is the one most frequently cited in media reports; and is based on work previously completed during the Obama administration (adjusted for inflation). The SCC estimate assumes a discount rate of 3.0 percent, which moderately trades off present costs into the future.[18] It should be noted that the current SCC estimates from the IWG range from $14 to $152 per metric ton, depending on the discount rate assumption.[19]

In addition, the IWG separately assigned interim social cost values to methane (CH_4) and nitrous oxide (N_2O) of $1,500 and $18,000 per ton of emissions, respectively, using a 3.0 percent discount rate assumption.[20]

When applied to Bay Area refineries, the proposed rule will eliminate about 2,514 tons of methane emissions. Using the alternate discount rate assumptions cited in the most current IWG report, the social cost reduction would range from $1.7 million to $9.8 million (Table 10). The anticipated costs of compliance for Rule 13-5 fall within the range of $15.3 -$17.7 million per year. The IWG is due to release a revised report in January 2021 that will account for more up-to-date climate change analysis and feedback.

[16] Center for Biological Diversity v. National Highway Traffic Safety Administration; November 15, 2007. https://caselaw.findlaw.com/us-9th-circuit/1024716.html

[17] Cho, Renee, and Columbia Climate School; "Social Cost of Carbon: What Is It, and Why Do We Need to Calculate It?"; April 1, 2021. https://news.climate.columbia.edu/2021/04/01/social-cost-of-carbon/

[18] Interagency Working Group on Social Cost of Greenhouse Gases, United States Government; *Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates Under Executive Order 13990*; February 2021.

[19] The IWG's SCC estimates are based on averages of model runs using multiple different inputs. The scenarios include 5.0, 3.0, and 2.5 percent discount rates, with an additional scenario that uses a 3.0 percent discount rate at the 95th percentile of the modeling results.

[20] The cost factor assumes 2020 dollar values, using the previous estimates dating back to 2016 and adjusted for inflation using the US Bureau of Economic Analysis' GDP price deflator values.

Table 10: Estimated Social Cost of Methane Emissions

Discount Rate Assumption	5.0% (50th Percentile)	3.0% (50th Percentile)	2.5% (50th Percentile)	3.0% (95th Percentile)
Social Cost Per Metric Ton of CH4	$670	$1,500	$2,000	$3,900
Social Cost (2,514 tons of CH4)	$1,684,705	$3,771,727	$5,028,969	$9,806,491

Source: ADE, Inc.; data based on Interagency Working Group report, "Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates Under Executive Order 13990"; February 2021.

SMALL BUSINESS DISPROPORTIONATE IMPACTS

According to the State of California, among other things, small businesses generate annual sales of less than $10 million.[21] Of the six sources affected by the proposed rule, none are small businesses. As a result, small businesses are not disproportionately impacted by Proposed Rule 13-5.

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