SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT

Preliminary Draft Staff Report

Proposed Amended Rule 1118 – Control of Emissions from Refinery Flares

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EXECUTIVE SUMMARY

Rule 1118 – Control of Emissions from Refinery Flares (Rule 1118) was originally adopted by the South Coast Air Quality Management District (South Coast AQMD) Governing Board on February 13, 1998, and was amended three times since adoption, in 2005, 2017, and 2023. The intent of Rule 1118 is to monitor and record data on refinery and related flaring operations, and to control and minimize emissions from refinery flares. Rule 1118 establishes requirements for flares operated at petroleum refineries and related operations including requirements to submit notifications and reports, monitor emissions, meet emissions targets, and maintain a public inquiry hotline.

As part of the amendment to Rule 1118 in 2005, all refineries in South Coast AQMD were required to have flare gas recovery systems (FGR) installed, and since then the amount of flaring and flaring emissions has been reduced considerably. However, refineries continue to experience numerous flaring events each year. While most events have only a minor release of emissions, some are significant events that result in substantial emissions of many pollutants, along with dark plumes of smoke. The last major amendment to Rule 1118 was the 2017 amendment, which was the first phase of a planned two-phase amendment. The first phase primarily focused on establishing mechanisms to gather more information through scoping documents prepared by the owners and operators of regulated facilities. The current amendment is the second phase, which seeks further emission reductions from flares operated at petroleum refineries and related operations. Additionally, in 2017, Assembly Bill 617 (AB 617) was signed into state law and required strategy development to reduce toxic air contaminants and criteria pollutants in overburdened communities. During the development of the AB 617 Community Emission Reductions Program (CERP) for the Wilmington, Carson, West Long Beach community, community members expressed concern about refinery flaring events and the associated emissions.

Proposed Amended Rule 1118 – Control of Emissions from Refinery Flares (PAR 1118) is the second phase of the planned two-phase rule amendment and seeks to achieve further emission reductions from refinery flares. PAR 1118 relies upon the information gathered from the scoping documents submitted after the 2017 amendment and South Coast AQMD staff's investigations on flare emission reductions. PAR 1118 will achieve most of the AB 617 CERP air quality priorities for the Wilmington, Carson, West Long Beach community by establishing a more stringent sulfur dioxide performance target, a new performance target for oxides of nitrogen emissions from clean service flares at hydrogen production plants, and a throughput threshold for liquified petroleum gas (LPG) clean service flares at refineries. PAR 1118 is estimated to achieve a 50 percent reduction in sulfur dioxide which will fulfill the sulfur dioxide emission goal of AB 617 CERP for the Wilmington, Carson, West Long Beach community.

As part of PAR 1118, staff is recommending to:

1. Lower annual SO_2 performance target threshold for all facilities;
2. Establish a new annual performance target for oxides of nitrogen (NOx) for clean service flares at hydrogen production plants;
3. Include new requirements for LPG clean service flares at refineries;
4. Increase mitigation fees based on the most recent consumer price index (CPI); and
5. Update and standardize reporting requirements for facilities through the flare event notification system (FENS).

PAR 1118 was developed through a public process that included five Working Group Meetings and will include a Public Workshop and a Public Consulting session for the community members.

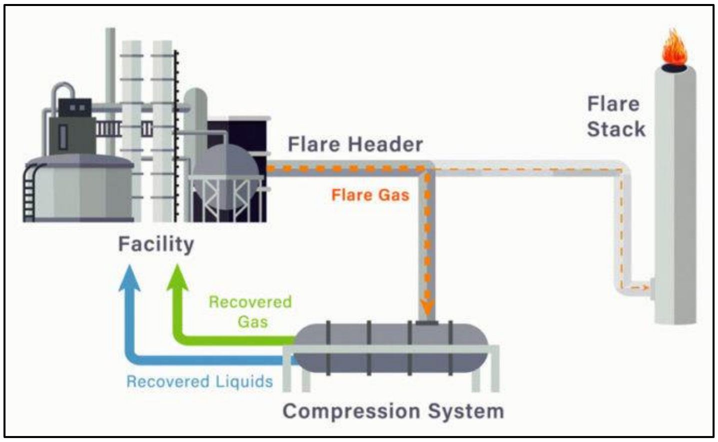
CHAPTER 1 : BACKGROUND

INTRODUCTION

Rule 1118 – Control of Emissions from Refinery Flares (Rule 1118) was originally adopted by the South Coast Air Quality Management District (South Coast AQMD) Governing Board on February 13,1998. The intent of Rule 1118 is to control and minimize emissions from refinery flares. Rule 1118 establishes requirements for flares operated at petroleum refineries and related operations including requirements to submit notifications and reports, monitor emissions, meet emissions targets, and maintain a public inquiry hotline.

In recent years several incidents at some refineries, including offsite power disruptions and onsite process unit breakdowns, resulted in flare events and increased emissions that impacted the air quality of neighboring communities. The amount of flaring that has occurred in recent years has varied, with some refineries flaring more than others. As part of the amendment to Rule 1118 in 2005, all refineries in the South Coast AQMD were required to have flare gas recovery (FGR) systems installed, and since then the amount of flaring and flaring emissions has been reduced considerably.

Vent gases generated during the refining process (typically hydrocarbons) are often sent to the FGR system. The figure below demonstrates a flare gas recovery system at a refinery and its different components. FGR systems recover vent gas and inject it into the refinery's fuel gas system for use in other processes, such as steam boilers. Flaring occurs when the FGR system is unable to handle the amount or type of gases being directed into the system, whether due to unplanned flare events like external power disruptions or onsite emergencies, or from planned flare events like refinery turnarounds. Under such circumstances, FGR systems route the extra vent gas to the flare where it is discharged into the atmosphere at the flare tip to avoid unsafe over-pressurization. These gases are combusted at the flare tip to reduce associated emissions and avoid possible buildup of combustible gases. While this simplified explanation describes why flaring occurs, flaring events at different refineries or related operations are caused by a variety of factors and due to the complexity of each refinery, the owner or operator of facilities have varying abilities to prevent or handle the excess vent gas being generated during those events.



(Image Courtesy: Politico)

Figure 1-1. Refinery Flare Gas Recovery System

Refineries continue to experience numerous flaring events each year. While most events have only a minor release of emissions, some are significant events that result in substantial emissions of many pollutants, along with dark plumes of smoke. Proposed Amended Rule 1118 – Control of

Emissions from Refinery Flares (PAR 1118) seeks to achieve further emission reductions from refinery flares. This amendment will implement the second phase of the planned two-phase rule amendment and will achieve most of the air quality priorities that were set forth by Assembly Bill 617 (AB 617) Community Emission Reductions Program (CERP) for the Wilmington, Carson, West Long Beach community.

The amendments being sought or considered in PAR 1118 include:

1. Lower annual sulfur dioxide (SO_2) performance target threshold for all facilities;
2. New annual oxides of nitrogen (NOx) performance target for clean service flares at hydrogen production plants;
3. New requirements for clean service flares at refineries (i.e., flares for liquified petroleum gas tanks);
4. Increased mitigation fees based on the most recent consumer price index (CPI); and
5. Updated and standardized reporting requirements for facilities through the flare event notification system (FENS).

Each of these proposed amendments is described in more detail in this staff report.

REGULATORY BACKGROUND

Rule 1118 was originally adopted by South Coast AQMD Governing Board on February 13, 1998. The intent of the rule is to minimize emissions from refinery flares and require petroleum refineries and related operations to monitor, record, and report flare emissions data. The rule was amended three times since adoption, in 2005, 2017, and 2023.

2005 Amendment

When the rule was adopted in 1998, the Governing Board directed staff to analyze the monitoring data submitted by the refineries and related facilities from October 1, 1999, through December 31, 2003. Staff presented the findings in a report to the South Coast AQMD Governing Board on September 3, 2004, which concluded that refinery flaring was significant enough to warrant the implementation of controls to reduce emissions. The report identified that the prevention of flaring of excess fuel gas, the elimination of leaks from pressure relief devices, and reductions of routine flaring were the most effective approaches to reduce emissions from refinery flaring. The report also concluded that the flare reduction goals can be achieved with the installation of flare gas recovery systems and gas treating systems, expanding the capacities of existing flare gas recovery systems and existing gas treatment systems, and addressing the leak from pressure relief valves. Furthermore, the report also recommended improvements in the measurement of flare vent gas flows and installations of continuous monitoring systems to measure the total sulfur concentration and the higher heating value of the flared gas, as well as standardized methodologies to calculate vent gas flow rate, emissions, and missing data.

The 2005 amendments to Rule 1118 implemented the objectives identified in the report and established a SO_2 performance target of 0.5 ton per million barrel of crude processing capacity.

2017 Amendment

In 2012, U.S. EPA initiated a review of its Refinery Regulations, New Source Performance Standards (NSPS), National Emission Standards for Hazardous Air Pollutants (NESHAP), and Maximum Achievable Control Technology (MACT) I and MACT II regulations for refinery process units and ancillary equipment operations which included the operation of refinery flares. U.S. EPA's review resulted in updates to the requirements in the Refinery Sector Rule, which was finalized in December 2015. The updated federal requirements for flaring focused on reducing significant flaring events and ensuring that when a flaring event does occur, combustion is as efficient as possible to reduce associated emissions. Furthermore, in December 2016, U.S. EPA also revised its Air Pollution Emission Factors (AP-42) guidance for estimating volatile organic compound (VOC) emissions from flaring events stating that using the total hydrocarbon (THC) emissions factor may not be appropriate for reporting VOC emissions when an emissions factor exists for VOC. The updated AP-42 emission factor for VOC emissions was increased about 10-fold (from 0.063 to 0.66 pound of VOC per million British thermal units or lb/MMBtu) which is applicable to "well-operated flares achieving at least 98 percent destruction efficiency."

The 2017 amendment consisted of a phased approach; staff proposed to amend the rule in two rulemaking phases, with Phase II of rulemaking to occur later based on the information gathered in Phase I. Phase I primarily focused on establishing mechanisms to gather more information through scoping documents prepared by the owner and operators of regulated facilities and updated the rule for consistency with federal requirements. Phase I consisted of the following changes to the rule:

- Harmonizing Rule 1118 with the most significant provisions from US EPA's 2015 Refinery Sector Rule update regarding flares, including new prohibitions on certain types of flaring events;
- Aligning Rule 1118 with AB 617 CERP requirements;
- Requiring all facilities subject to Rule 1118 to prepare a Scoping Document that evaluates the feasibility of eliminating or minimizing planned and unplanned flaring events;
- Setting the requirements for regulated facilities to submit notifications and reports, monitor emissions, meet emissions targets, and maintain a public inquiry hotline;
- Removing the $4 million annual cap on mitigation fees paid by facilities for flaring;
- Updating the VOC emission factors based on EPA's updated AP-42 guidance;
- Updating and clarifying reporting requirements for facilities which are required to submit notifications, reports, monitor emissions, meet emission targets, and maintain a public inquiry hotline.

South Coast AQMD Follow-up Actions to 2017 Amendment to Rule 1118

As part of the Phase I amendment to Rule 1118 in 2017, staff incorporated the most significant portions of the U.S. EPA Refinery Sector Rule (RSR) along with other proposed amendments. Staff postponed full incorporation of the remainder of the RSR to Phase II of the proposed rulemaking due to its complexity; however, staff is no longer proposing to incorporate all the remaining RSR requirements into Rule 1118 during this second phase of amendments. The requirements of RSR are being implemented by the permitting staff by incorporating the requirements into the facilities' Title V permits. This is a better approach to assure compliance with the RSR requirements. Staff is proposing to include some additional references to RSR in PAR 1118 where it helps clarify rule provisions.

Upon amendment of Rule 1118 in 2017, the South Coast AQMD Governing Board also directed staff to initiate the second phase of rulemaking on Rule 1118 in 2018, and draft amendments to Rule 1118 that would further reduce emissions from flaring for the Board's consideration no later than January 31, 2020. However, due to shifting priorities and limited resources, the rule amendment was delayed.

2023 Amendment

On September 21, 2022, U.S. EPA announced a limited approval and limited disapproval of the 2017 amendments to Rule 1118, effective on October 24, 2022.

The limited approval stated that Rule 1118 improves the state implementation plan (SIP) and is largely consistent with the relevant Clean Air Act (CAA) requirements. However, U.S. EPA proposed a limited disapproval stating that Rule 1118 paragraph (j)(1) and Attachment A paragraphs (4)(n) and (5)(n) provide "unbounded director's discretion" and as a result, the rule does not satisfy the requirements of CAA section 110. The 2017 version of Rule 1118 included several instances where the Executive Officer had the sole authority to approve American Society for Testing and Materials (ASTM) methods without further specificity regarding how this authority will be exercised. U.S. EPA stated that would undermine the enforceability of the submission, constitutes a SIP deficiency, and conflicts with CAA Section 110.

To address the U.S. EPA limited disapproval, staff proposed amendments to Rule 1118 to include a requirement that in addition to the South Coast AQMD's Executive Officer, the California Air Resources Board (CARB) and U.S. EPA must also approve ASTM standards not included in the rule. Staff could not delay the amendment as the CAA specifies that regions must attain the National Ambient Air Quality standards (NAAQS) by specific dates or face the possibility of sanctions by the federal government and other consequences, including but not limited to increased permitting fees, stricter restrictions for permitting new projects, and the loss of federal highway funds. South Coast AQMD had to address the announced deficiencies by April 24, 2024 (i.e., 18 months since the disapproval effective date), otherwise sanctions would be imposed. Thus, staff conducted a limited amendment to the rule to address U.S. EPA's disapproval and avoid sanctions. The 2017 version of Rule 1118 was amended by the South Coast AQMD Governing Board on January 6, 2023.

Assembly Bill 617

AB 617 was initially signed into law in 2017 as a statewide strategy to reduce toxic air contaminants and criteria pollutants in designated environmental justice communities, through establishing community-focused and community-driven actions to reduce air pollution and improve public health. Currently, there are six designated AB 617 communities in South Coast AQMD jurisdiction, as follows:

- Wilmington, Carson, West Long Beach Community
- San Bernardino, Muscoy Community (SBM)
- East Los Angeles, Boyle Heights, West Commerce Community (ELABHWC)
- Southeast Los Angeles Community (SELA)
- Eastern Coachella Valley Community (SLA)
- South Los Angeles Community (ECV)

Most of the regulated facilities subject to Rule 1118 are located in the Wilmington, Carson, West Long Beach community.

AB 617 Community Emissions Reduction Plans (CERPs)

AB 617 CERPs seek to address the community's highest air quality priorities with actions that reduce air pollution emissions from sources within the local community and that provide a blueprint for achieving reductions in air pollution exposure to people in each community. The plan for the Wilmington, Carson, West Long Beach community started in 2019 and is expected to be implemented over several years.

The Wilmington, Carson, West Long Beach community identified flare emissions from refineries as one category of the air quality priorities to be addressed by that CERP. Action items for Rule 1118 are as follow:

- Lower performance targets and/or increase mitigation fees
- Increase capacity of vapor recovery systems to store gases during shutdowns
- Header modifications for gas diversion with process controls
- Back-up power systems for key process units
- Remote optical sensing for flare emission characterization
- Lower-emission flaring technologies
- Additional flare minimization plans

The implementation period of the actions in the Wilmington, Carson, West Long Beach CERP is expected to be approximately five years from 2019. PAR 1118 will address the CERP actions that were deemed technically feasible and is anticipated to be adopted within the five year period specified in the CERP.

SCOPING DOCUMENTS

Since a facility operator understands their process the best, the 2017 amendments to Rule 1118 required the operator of each facility to prepare and submit a Scoping Document within 12 months of rule amendment. Facility operators and owners were required to conduct an evaluation of the technical feasibility, approximate cost, and timing constraints to implement control options for minimizing or avoiding planned and unplanned flaring events. Each facility was required to evaluate two alternatives to eliminate planned flaring events and assess how to reduce emissions from planned flaring events to a level beyond 0.5 ton of SO_2 per million barrels of crude processing capacity. The scoping documents were reviewed and evaluated for further potential amendments.

AFFECTED FACILITIES AND EQUIPMENT

PAR 1118 affects 12 facilities, all of which are located within Los Angeles County. The facilities include eight petroleum refining facilities, three hydrogen production plants, and one sulfur recovery plant with a total of 31 existing flares affected by this proposed rule, as listed in the table below. Three flares are clean service flares operating at refineries LPG tank stations, four flares are clean service flares operating at hydrogen production plants, and the others are general service flares that are being operated at refineries and sulfur recovery plants.

Table 1-1. Regulated Facilities and Flares by PAR 1118

Facility Type	Facility Name	Number of Flares
Hydrogen Production Plant	Air Liquide	1
	Air Products Carson	1
	Air Products Wilmington	1
Refinery	Chevron Products Company	6
	Paramount Petroleum	1
	Phillips 66 Carson	2
	Phillips 66 Wilmington	4
	Tesoro Carson	5
	Tesoro Wilmington	2
	Ultramar/Valero	4
	Torrance Refinery	3
Sulfur Recovery Plant	Tesoro Sulfur Recovery Plant	1
TOTAL	**12**	**31**

Site Visits to Regulated Facilities

Staff conducted site visits to all regulated facilities between November 3, 2022, and January 18, 2023. Staff observed that each facility is unique in operation and structure. Seven out of twelve facilities operate clean service flares, including four clean service flares located at hydrogen production plants and three liquified petroleum gas (LPG) clean service flares. Staff noted that two out of three LPG clean service flare are operated in a manner where a continuous gas stream is being combusted in the flare.

Staff also noted that all facilities have FGR systems. Generated vent gases during the refining process are often sent to FGR to be recovered and injected back into the refinery's fuel gas system for use in other processes. Flaring occurs when the FGR system is unable to handle the amount or type of vent gas being directed into the system, and as a result, vent gas is routed to the flare to avoid over-pressurization. Flares operate as a safety mechanism and control device at the facilities. Vent gas is combusted at flare tip to reduce emissions and avoid the potential build-up of combustible gas. One limitation to recover the vent gas and route it to the refinery's fuel gas system is the facility's potential capability to use all the recovered vent gas. Facilities that can utilize a significant quantity of excess vent gas generally have the least amount of flaring. Larger facilities and facilities that operate gas turbine generators, which have the ability to combust a large volume of gas, have more flexibility to re-route vent gas from flare to their flare gas system.

Staff discussed the performance of FGR systems with industry stakeholders during their visits to regulated facilities. Over years, many facilities have reduced flaring emissions through operational changes, including slowing down shutdown process, increased reliability of process equipment, and renting thermal oxidizer to combust excess gases during scheduled shutdown and subsequent startup operations.

From the visits to hydrogen production plants, staff discussed different causes that lead to flaring at these facilities with the industry stakeholders. Most flaring at hydrogen production plants is originated from customer kick back, which is challenging for the hydrogen production plants to plan for or manage.

The following figure shows the dates of the site visits.

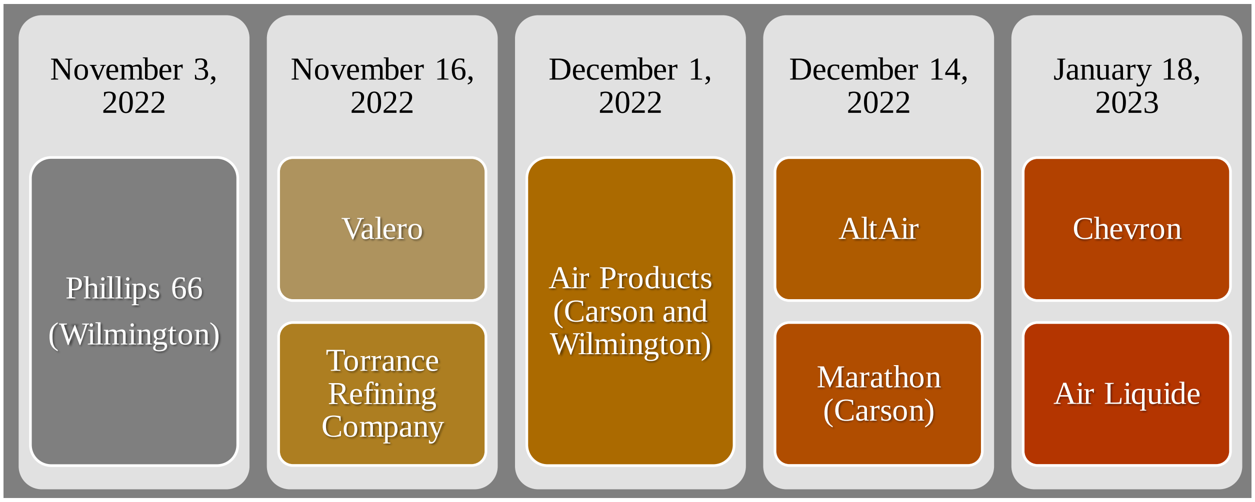


Figure 1-2. Staff's Site Visits to Regulated Facilities by PAR 1118

PUBLIC PROCESS

PAR 1118 was developed through a public process that included a series of Working Group Meetings. The table below summarizes the public meetings held throughout the development of PAR 1118 and provides a summary of the key topics discussed at each of the meetings. Staff began the rule development process in July 2022 and has conducted five Working Group Meetings to date. The Working Group is composed of affected facilities, environmental and community representatives, public agencies, consultants, equipment vendors, and interested parties. The purpose of the Working Group Meetings was development of the proposed amendments and emission controls for PAR 1118, to provide all stakeholders an opportunity to discuss details of the proposed amendments, and to listen to stakeholder concerns with the objective of building consensus and resolving any issues. Staff also held individual stakeholder meetings as needed and conducted several site visits to the affected facilities.

Table 1-2. Summary of Public Meetings

Date	Meeting Title	Highlights
July 21, 2022	Working Group Meeting #1	• Rule development process • Background and regulatory commitments • Progress since the previous rule amendment
October 26, 2022	Working Group Meeting #2	• Analysis of historical flare events data • Limited proposed amendment to Rule 1118 to address EPA's limited SIP disapproval (WGM served as Public Workshop) • Presentation by representatives from R.A. Nichols Engineering (RANE) on their vapor storage technology

Date	Meeting Title	Highlights
November 3, 2022 – January 18, 2023		South Coast AQMD staff's site visits to regulated facilities by Rule 1118
December 2, 2022		Set Hearing
December 2, 2022		Released Draft Rule Language
January 6, 2023		Public Hearing
April 26, 2023	Working Group Meeting #3	• Follow-up to the comment letter received from Coalition of Environmental Groups on April 13, 2023 • Summary of staff's site visits to regulated facilities by Rule 1118 • Evaluation of flare events data • Evaluation of flaring at clean service flares and alternatives • Discussion of flaring at Hydrogen production plants • Summary of scoping documents prepared for petroleum refineries • Preliminary Concepts for PAR 1118 • Proposed updates to flare event notification system (FENS)
October 25, 2023	Working Group Meeting #4	• Presentation by representatives from Providence Photonics on remote sensing technologies • Proposal to lower sulfur dioxide performance target • Proposal to increase mitigation fees • Proposal for control of nitrogen oxides at Hydrogen production plants • Proposal and cost-effectiveness analysis for potential control of flaring emissions at LPG flares
December 8, 2023		Released Initial Preliminary Draft Rule Language
December 12, 2023	Working Group Meeting #5	• Proposal for control of nitrogen oxides at Hydrogen production plants • Rule language and structure changes overview
January 19, 2024		Released Preliminary Draft Rule Language and Preliminary Draft Staff Report
February 8, 2024		Public Workshop
February 16, 2024		Public Consulting Session
February 16, 2024		Stationary Source Committee
March 1, 2024		Set Hearing
March 5, 2024		Released Draft Rule Language and Draft Staff Report
April 5, 2024		Public Hearing

CHAPTER 2 : EVALUATION OF FLARING EQUIPMENT AND DATA

INTRODUCTION

HISTORIC FLARING EMISSIONS DATA

SPECIFIC CAUSE ANALYSIS REPORTS (SCAR)

FLARE EVENT NOTIFICATION SYSTEM (FENS)

SCOPING DOCUMENTS

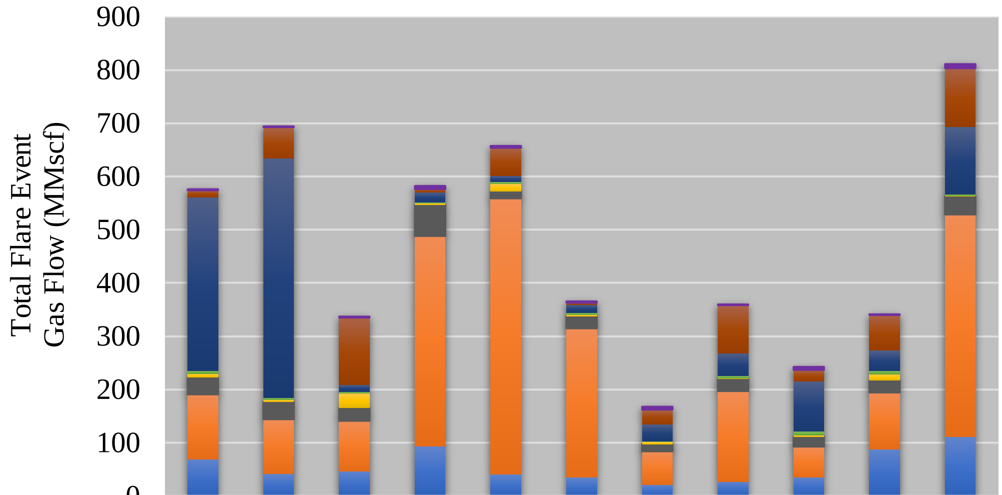
INTRODUCTION

Flaring is a process that controls VOC by routing them to a remote, usually elevated, location where it is combusted in an open flame and open-air set-up using a specially designed burner tip. Flares operate as a safety mechanism and control device, but the process of flaring can also produce undesirable byproducts including SOx, NOx, PM, CO, smoke plumes, noise, and large visual flame. However, through proper design and operation these undesired byproducts can be minimized. The majority of refineries and hydrogen plants have flare systems designed to relieve and vent a large volume of gas during emergency process upsets. Many flare systems at refineries are operated in conjunction with a baseload gas recovery system referred to as FGR. These systems recover and compress the VOC by combining it with the refinery fuel gas system for use as fuel for process heaters, boilers, and gas turbines. FGR systems allows the flare system to be used as a backup to handle emergency release situations. Depending on the quantity and quality of the VOC stream that can be recovered by FGR, there can be an economic advantage to recover the VOC rather than combusting it in the flare system alone.

Depending on the flare's design and application, flares may be used to service one or several processing units to control small or large volume of vent gas during an emergency. Therefore, flares can be classified into two main categories: general service flares and clean service flares. General service flares are used to dispose of vent gas from routine operations such as startups and shutdowns, turnaround activities, purged gas streams, and emergency vent gas release from process units' upsets. A clean service flare is used to only burn natural gas, hydrogen, liquified petroleum gas (LPG), or other gases with a fix composition vented from a specific equipment; the vent gas contains little to no sulfur, and the quality of the vent gas is usually predictable regardless of flaring events. Clean service flares can further be subcategorized as either a hydrogen flare or non-hydrogen LPG (propane and butane) flare. As the names imply, hydrogen service flares are located at hydrogen production plants and LPG flares are located at the propane and butane storage areas of a refinery.

HISTORIC FLARING EMISSIONS DATA

Facilities have been submitting quarterly reports to South Coast AQMD for more than a decade. Quarterly reports contain flare events details including date, duration, cause, level of emissions, etc. Staff compiled all flare events data reported by regulated facilities' owners and operators in quarterly reports (during 2012 to 2021) to analyze flare event frequency and magnitude. Historical vent gas flared, as reported by regulated facilities in their Rule 1118 in quarterly reports, excluding hydrogen production plants, is depicted in the figure below.



	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Altair Paramount	2	1	2	6	3	2	5	1	5	1	7
Chevron Products Co.	13	59	126	6	53	4	28	90	22	66	110
Marathon LAR Carson	326	449	13	19	11	15	31	43	94	38	126
Marathon LAR Wilmington	5	4	2	2	4	4	2	4	8	6	3
Marathon SRP	0.0	0.1	0.1	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0
Phillips LAR Carson	7	3	27	3	14	2	4	1	2	11	1
Phillips LAR Wilmington	32	33	25	58	13	23	13	23	19	23	34
Torrance Refining Company	122	103	94	395	518	280	63	170	57	107	418
Valero/Ultramar	69	41	47	93	41	35	21	27	36	88	111

Figure 2-1. Total Flare Event Gas Flow by Facility (million standard cubic feet)

The following figure plots annual flaring emissions as reported for regulated facilities in quarterly reports, excluding hydrogen production plants. Note that the increase in VOC emissions during the recent years partially reflects an increase in the VOC emission factor that was adopted in the 2017 amendment of Rule 1118.

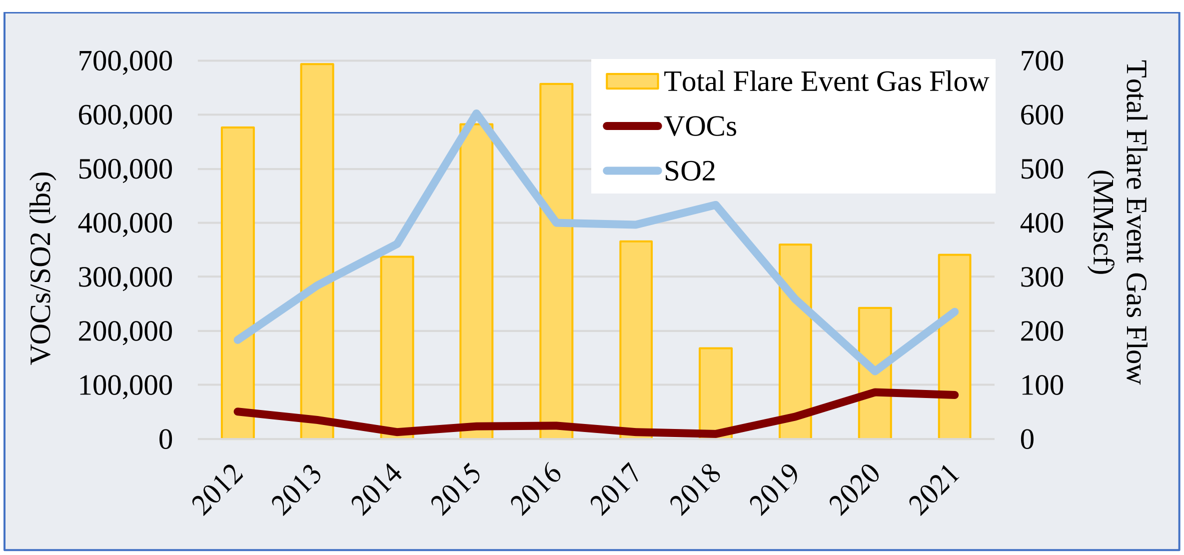


Figure 2-2. Annual Flaring Emissions as Reported by Refineries in Quarterly Reports

Facility owners and operators use 16 codes to classify the cause(s) of flare events in quarterly reports, as presented in the table below.

Table 2-1. Categories for Relative Cause of Flare Events

Cause Codes	Description
Code 0	Undetermined (use only if flow was more than 5,000 but smaller than or equal to 500,000 scf, and a cause analysis did not reveal a cause)
Code 1	Turnaround Activity (Excluding planned maintenance and planned start-ups and shutdowns)
Code 2	Planned Maintenance (Excluding turnarounds, and planned start-ups and shutdowns)
Code 3	Emergency Flaring (includes any unplanned shutdown, subsequent start-up, valid breakdown, etc.)
Code 4	Planned Start-up or Shutdown (Excluding planned maintenance and turnarounds)
Code 5	EON - Relief Valve Leakage due to malfunction
Code 6	Non-Emergency Flaring (For use only if no other code is the primary cause of the flare event)
Code 7	Process Vent (i.e., facilities/units with no vapor recovery installed) – use only if flow was more than 5,000 but smaller than or equal to 500,000 scf
Code 8	EON - Temporary Fuel Gas Imbalance
Code 9	Code unassigned - Reserved for future use
Code 10	Minor Vent (may only be used for vent gas flow less than 5,000 scf)
Code 11	EON - Unrecoverable Stream
Code 12	EON - Clean Service Stream
Code 13	EON - Intermittent Minor Venting
Code 14	EON - Pressure/Temperature Excursion
Code 15	Purge Gas (i.e., refinery fuel gas, no flare gas recovery installed)

Facilities report flare events in the quarterly reports using the cause codes. Staff evaluated flare events data in quarterly reports for frequency of flare events by code (2012 – 2021), as presented in the figure below. Results demonstrate that more than 80 percent of the events (i.e., counts) that occurred between 2012 and 2021 were either minor gas vent or clean service stream.

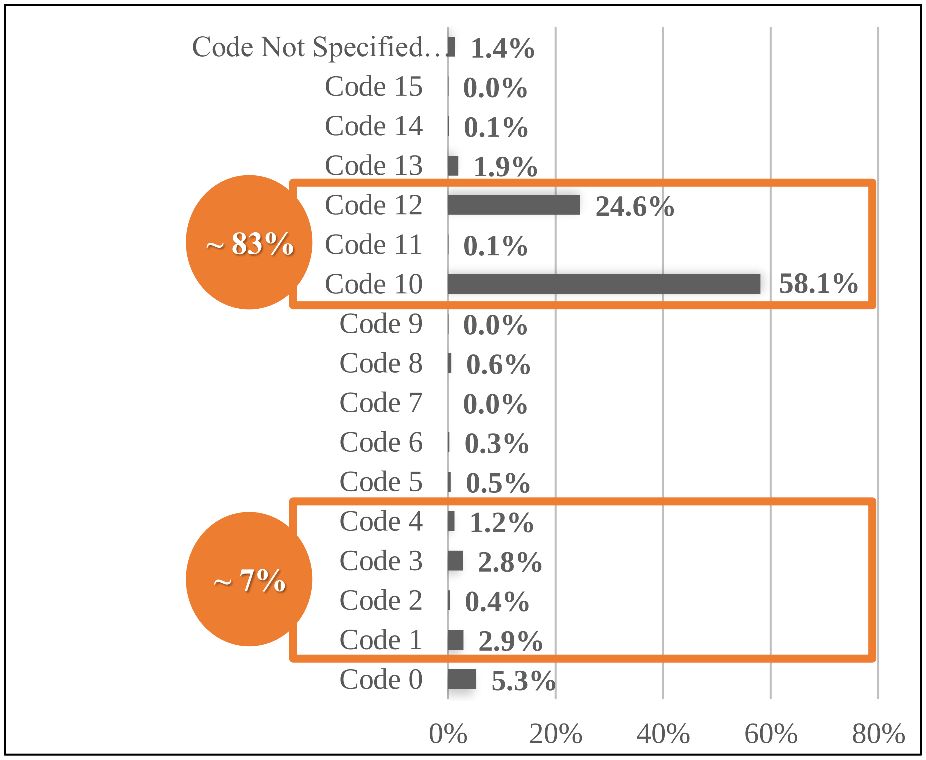


Figure 2-3. Flare Events Frequency by Cause Code (2012 – 2021)

Summary of reported data on the volume of flared vent gas for each regulated facility in quarterly reports is presented in the figure below. According to historic flaring data, reducing the frequency of flare events may not be the ultimate path towards reducing emissions from flaring. Data shows that seven percent of the flare events (by counts) caused more than 70 percent of total flared vent gas (2012 – 2021):

- Planned maintenance (Code 2) and planned startup/shutdowns (Code 4) generated about 27 percent of total flared vent gas.
- Emergency flaring (unplanned shutdown, subsequent start-up, valid breakdown, etc.) (Code 3) generated about 34 percent of total flared vent gas.

Reduction in flaring emissions is achievable by lowering frequency of flaring, including the frequency of flaring at clean service flares, as well as reducing the amount of vent gas being combusted at the flare through implementing operational improvements and conducting alternative practices to flaring.

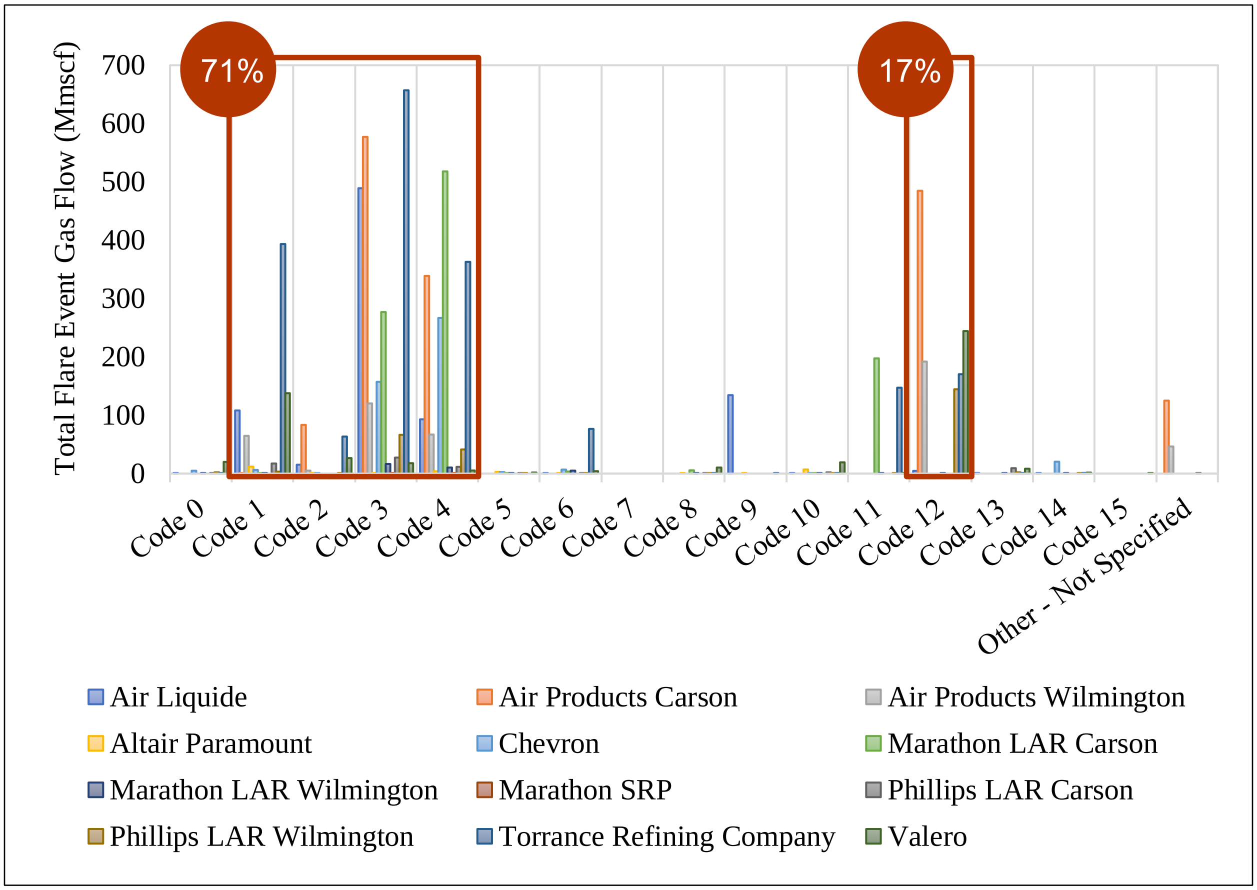


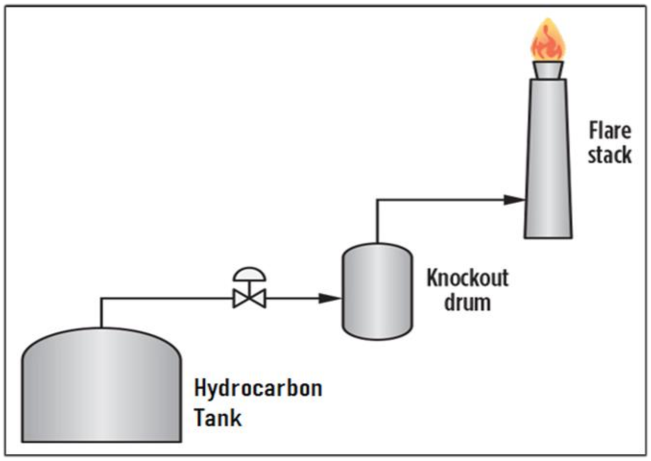
Figure 2-4. Total Gas Flow of Flare Events by Cause Code and by Facility (2012 – 2021)

Clean Service Flares

Clean service flare refers to a flare that is designed and configured by installation to combust only clean service streams, such as natural gas, hydrogen gas, liquefied petroleum gas, and/or other gases with a fixed composition that inherently have a low sulfur content. Quarterly reports indicate that "flaring clean service streams (Code 12)" as a significant cause for flaring. Over 10 years, flaring clean service streams was accounted for 25 percent of the flare events by counts and constituted 17 percent of the total flared vent gas. Flaring clean service streams solely at facilities other than hydrogen production plants accounts for eight percent of the flare events by counts and eight percent of the total flared vent gas.

Non-Hydrogen Clean Service Flares

Clean service flares at facilities other than hydrogen production plants are defined as "nonhydrogen clean service flares" and are operated to control the pressure of refinery product tanks that store either propane or butane, through combusting the off gas from the tanks. The figure below depicts the schematic configuration of a non-hydrogen clean service flare attached to an LPG tank. These flares are also referred to as LPG flares due to the location and type of vent gas that is being combusted.



(Image Courtesy: GAS PROCESSING & LNG)

Figure 2-5. Non-Hydrogen Clean Service Flare at Refinery

Three facilities operate a non-hydrogen clean service flare (one flare per each facility), with significant amounts of vent gas flaring occurring at two out of three of these flares. Vent gas flow from these two flares represents high proportion out of the total flared vent gas at each facility, as shown in the figure below.

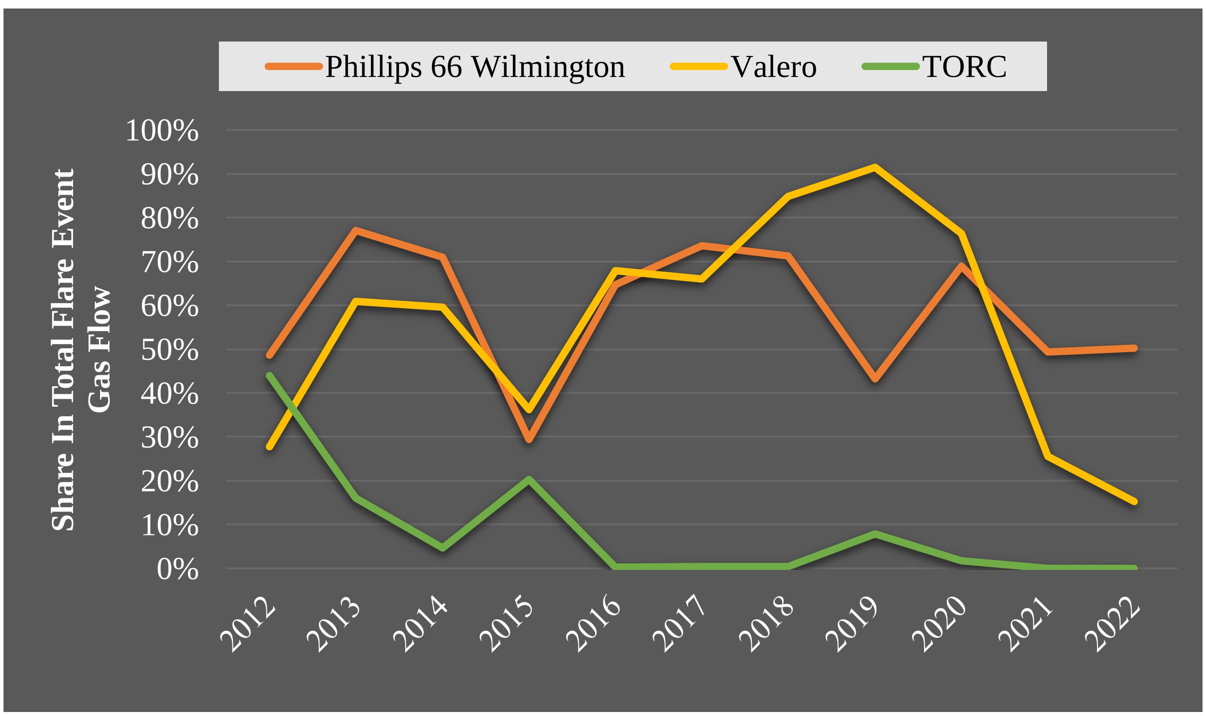


Figure 2-6. Share of Flared Vent Gas Form Non-Hydrogen Clean Service Flare vs. Total Flared Vent Gas by Facility

Clean service stream is a vent gas stream with inherently low sulfur content. Sulfur dioxides emissions are calculated using emission factors for each specific vent gas stream, e.g., propane, butane, natural gas, etc. However, facilities have the option to use an alternative method to calculate the emissions for non-hydrogen clean service flare using gas stream sampling. The alternative method is stated in the facility's approved Flare Monitoring and Recording Plan

(FMRP). Based on the data in quarterly reports, flaring at nonhydrogen clean service flares does produce sulfur dioxides emissions (see the figure below). In addition, flares are a source of oxides of nitrogen (NOx) emissions, which is the main pollutant responsible for the high ground level ozone concentrations in the South Coast AQMD.

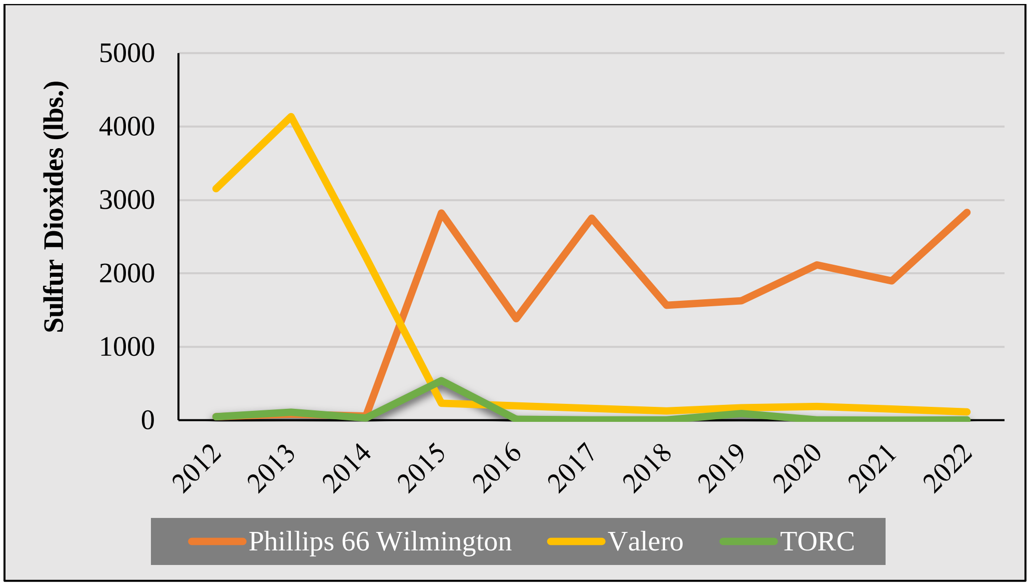


Figure 2-7. Sulfur Dioxides Content from Clean Service Flares by Facility

Rule 1118.1 and Regulated Flares Located at Oil and Gas Production Facilities

Non-hydrogen clean service flares subject to Rule 1118 serve the same purpose as the flares located at tank terminals which are subject to Rule 1118.1, where the former rule seeks to control and minimize flaring and flare related emissions to reduce NOx and VOC emissions from flaring.

Rule 1118.1 – Control of Emissions from Non-Refinery Flares (Rule 1118.1) was adopted on January 4, 2019, to regulate NOx and VOC emissions from non-refinery flares located at landfills, wastewater treatment plants, oil and gas production facilities, organic liquid loading stations, and tank farms. Rule 1118.1 set specific capacity thresholds for each type of industry and Rule 1118.1 facilities are required to maintain their flare throughput below an annual capacity threshold (Rule 1118.1 Table 2). Any regulated flare under Rule 1118.1 that operates at a level greater than the specified capacity threshold for two consecutive years is required to implement at least one of the following actions:

- Reduce the level of flaring to below the capacity threshold (e.g., through beneficial use strategies)
- Replace the flare with a unit that complies with the lower NOx emissions limits.

Staff is proposing a similar approach for the non-hydrogen clean service flares regulated by Rule 1118 by establishing a throughput threshold. If a flare exceeds the threshold, the owner or operator would have to reduce the flare throughput.

Hydrogen Clean Service Flares

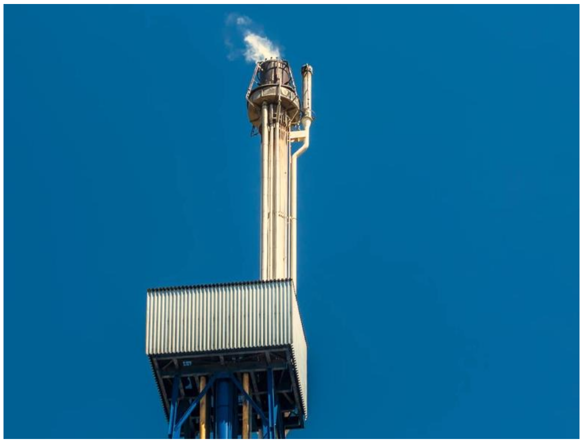
Hydrogen production plant produces hydrogen from refinery fuel gas via steam methane reforming and pressure swing adsorption purification process. The produced hydrogen is supplied to refineries for use in various hydro-processing units. The purpose of flares at hydrogen production plants is to control emissions in the syngas (mainly a mixture of hydrogen and carbon monoxide) and pressure swing adsorption off-gas that is generated during abnormal plant operations, such as startup, shutdown, customer kick-back, and process upset conditions. The composition of streams to hydrogen clean service flares are lighter than those that would be vented at a refinery flare and mainly consists of hydrogen, methane, nitrogen, and carbon dioxide.

There are four hydrogen production plants regulated under Rule 1118 that provides hydrogen for local petroleum refineries via either a shared, medium-pressure product pipeline or direct high-pressure product pipelines. Rule 1118 hydrogen production plants operate two types of clean service flares:

- Enclosed/shrouded ground flare (Figure 2-8)
- Elevated flare (Figure 2-9)

Clean service flares located at hydrogen production plants are referred to as hydrogen clean service flares in this report. Hydrogen clean service flares use either nitrogen or natural gas as purge gas. Nitrogen does not combust, but natural gas combusts and generates NOx emissions.

(Image Courtesy: ZEECO®)
Figure 2-8. Enclosed Ground Flare

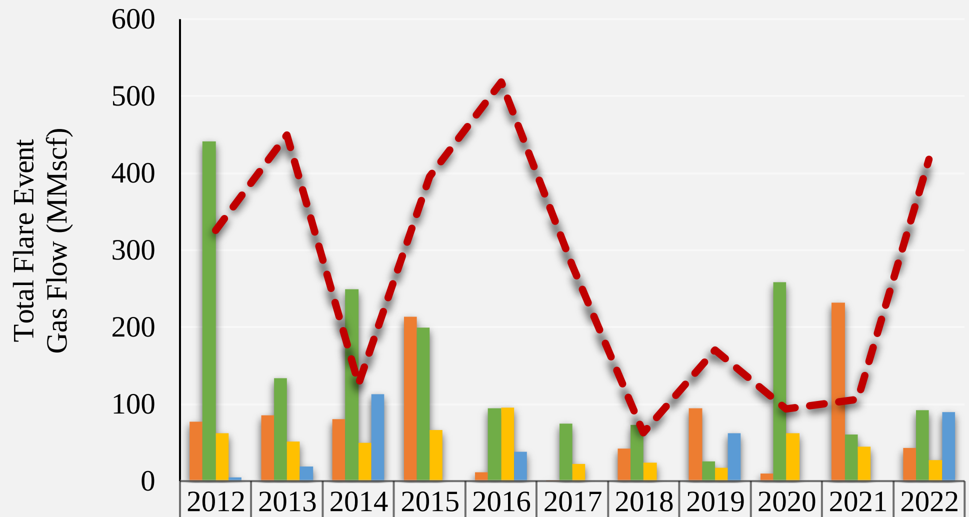


(Image Courtesy: Blackridge)
Figure 2-9. Elevated Flare

Three hydrogen production plants (Air Liquide, Air Products Wilmington, and Chevron) operate ground flares and one plant (Air Product Carson) operates an elevated flare. Air Products also operate two other hydrogen production plants located at Torrance Refinery site since 2022 which shares the refinery's general service flare system during any flare event that occurs at the hydrogen production plant. Staff excluded these two hydrogen production plants from evaluation of flaring emissions for hydrogen clean service flares. More information about these hydrogen production plants is provided later in this report.

In general, hydrogen production plants have flare events every day. Evaluation of flare event data reported in quarterly reports for hydrogen clean service flares shows that while most of these flare events were below the notification thresholds established in Rule 1118, about two percent of the flare events exceeded at least one of the established thresholds.

While the composition of vent gas stream to hydrogen clean service flares is mainly pure hydrogen, the annual amount of total vent gas flow to such flares is comparable in magnitude to the total annual amount of vent gas flow to the flare(s) at a petroleum refinery. The figure below presents an overview of total vent gas flow from Rule 1118 hydrogen clean service flares compared to total vent gas flow that flared at the refinery with the highest level of flaring vent gas in the corresponding year (i.e., maximum of all refineries).



	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Air Liquide	77	86	80	214	11	0	42	95	10	232	43
Air Products Carson	441	133	249	200	94	75	73	25	258	60	92
Air Products Wilmington	62	52	50	67	95	23	24	17	62	44	27
Chevron	5	19	113	0	38	0	0	62	0	0	90
Maximum of All Refineries	326	449	126	395	518	280	63	170	94	107	418

Figure 2-10. Total Flared Vent Gas from Hydrogen Clean Service Flares by Facility

The level of sulfur content in the flare gas flow to hydrogen clean service flares is low. SO_2, if present, is the byproduct of combusting natural gas and refinery fuel gas as feedstock to pilots. The figure below shows the amount of SO_2 in the flared vent gas at the hydrogen clean service flares regulated by Rule 1118. This level of SO_2 is lower by a factor of 1,000 compared to the level of SO_2 in total flared vent gas at the refinery with the highest level of flaring vent gas in the corresponding year.

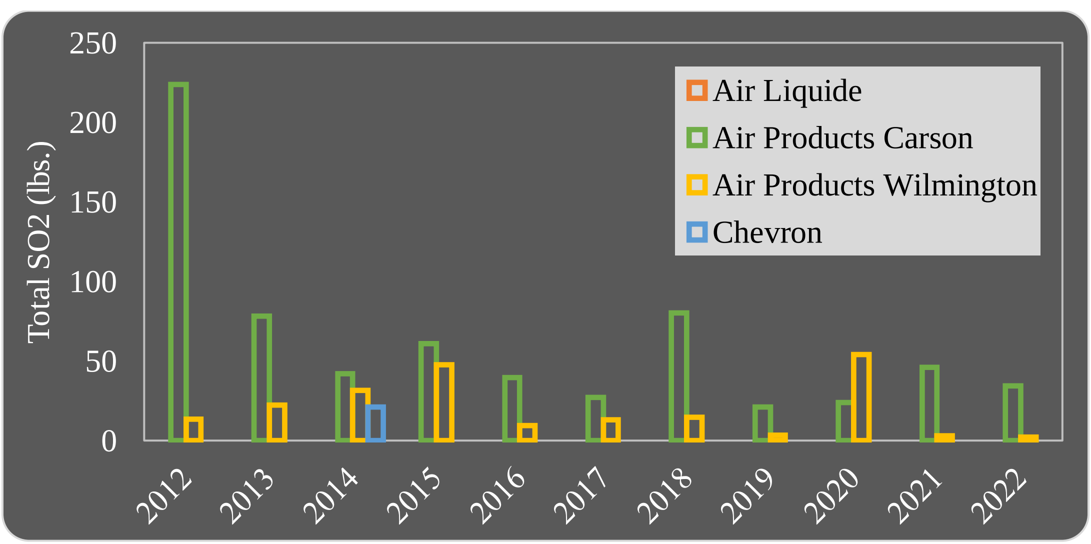


Figure 2-11. Sulfur Dioxides from Hydrogen Clean Service Flares by Facility

Air Products Hydrogen Production Plants Located at Torrance Refinery

Air Products is currently operating two hydrogen production plants located at Torrance Refinery site. These hydrogen production plants were sold to Air Products in 2020 and Air Products took over the operation at hydrogen production plants in May 2022. The two hydrogen production plants are operated exclusively by Air Products, but the generated flare vent gas at these plants is directed to the Torrance Refinery's flare gas recovery system and general service flares.

Based on the current configurations, the vent gas streams from the refinery and hydrogen production plants are combined. The hydrogen production plants are connected to the refinery general service header and vent to the common flare header. The capacity of Torrance Refinery's flare gas recovery system may not be always sufficient to recover the high volumes of vent gas generated due to a flare event at the hydrogen production plants. As a result, the generated vent gas by hydrogen production plants causes flare events to occur at Torrance Refinery as well. Due to common header, when a flare event is initiated at the hydrogen production plants, refinery gas is also swept into the flare stream resulting in SO_2 emissions.

Specific Cause Analysis Reports (SCARs)

Rule 1118 requires the owners and operators of facilities to submit Specific Cause Analysis Reports (SCARs) identifying the cause of any flare event, excluding planned shutdown, planned startup, and turnarounds, when any of the following thresholds is exceeded: 100 pounds of VOC emissions, 500 pounds of sulfur dioxide emissions, or 500,000 standard cubic feet of vent gas is combusted. A SCAR is required to be prepared and submitted for a flare event that occurred during a planned shutdown, planned startup, or turnaround if it was as a result of a non-standard operating procedure. SCARS are expected to include the cause and duration of the flare event as well as any mitigation and corrective actions taken or to be taken to prevent the recurrence of a similar event.

Review of SCARs submitted to South Coast AQMD since 2009 shows that besides the aforementioned excluded causes, flare events have occurred as a result of equipment or instrument operational failure, equipment or instrument malfunction (physical damage), equipment tripping, piping failure (e.g., leakage), and loss of external or internal power sources.

Staff evaluated historical flare data to investigate the contribution of flare events associated with internal and external power loss to the total amount of flaring at facilities subject to Rule 1118. Flare events due to internal power loss are accountable for eight percent of flare events by count and flare events due to external power loss are accountable for five percent of flare events by count. Review of flare events data also shows that flaring due to external power loss has been more frequent in recent years (see the table below). This is an area where the owners and operators of facilities can take actions to reduce flare emissions below performance targets by upgrading electrical reliability at their facilities. For instance, one facility installed underground feeder lines at the cost of $75 million.

Table 2-2. Flare Events due to External Power Loss

Year	Count of Flare Events Caused by External Power Loss
2011	1
2012	1
2014	1
2016	3
2017	2
2018	1
2019	3
2021	6

The table below shows the share of flare events associated with internal power loss in the total amount of vent gas at different facilities. Many of the refineries have very low flare emissions caused by internal power loss though there is an opportunity for some to make improvements to reduce flare emissions through internal improvements.

Table 2-3. Total Flared Gas due to Internal Power Loss (Percent of Total Vented Gas/year)

Year	Chevron	Marathon	P66 Wilmington	P66 Carson	Torrance	Valero
2013	-	-	1%	-	-	-
2014	-	-	-	-	-	5%
2015	13%	-	-	-	-	-
2016	16%	-	-	-	-	-
2017	28%	-	6%	36%	-	-
2018	52%	-	0.01%	-	-	-
2019	-	-	-	-	-	-
2020	-	-	-	-	-	-
2021	0.2%	5%	-	21%	-	-

FLARE EVENT NOTIFICATION SYSTEM (FENS)

FENS is a web-based notification system[1] for facilities to submit notifications as required by Rule 1118. An enhanced version of FENS was initially launched in 2019 which includes an interactive map, real time data, and historical flaring information. FENS was updated in 2020 to

[1] South Coast AQMD Flare Events Notification System, Access at: https://xappprod.aqmd.gov/FENS/public

include new features, including wind speed and direction, list of recent events, etc. The figure below presents the FENS platform as accessible to the public.

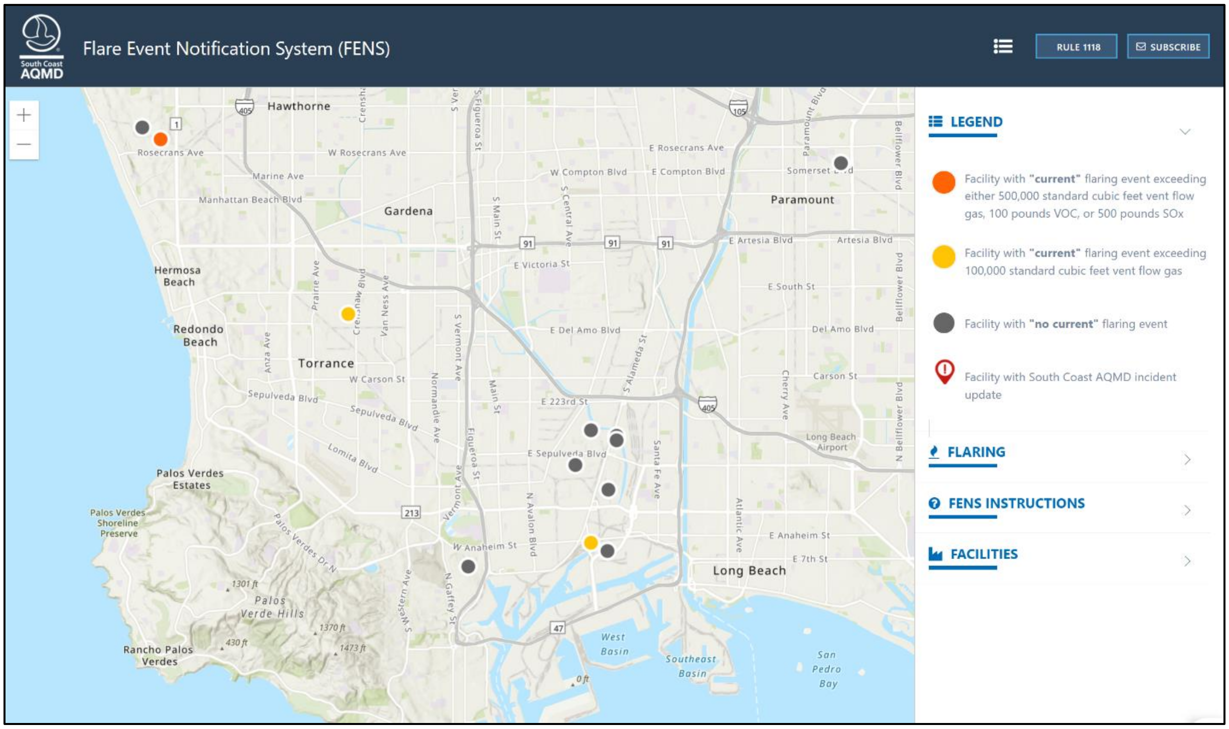


Figure 2-12. FENS Public Platform

The figure below shows the count of planned and unplanned flare events by year (2020 – 2023). This figure only includes the flare events that exceeded the established Rule 1118 thresholds, i.e., 500,000 standard cubic feet of total vent gas, 500 pounds of SO_2 emissions, and 100 pounds of VOC emissions. Other flare events are required to be reported by the facilities' owners or operators in the quarterly reports, but not in FENS. The figure below shows that the count of unplanned flare events that exceeded the established Rule 1118 thresholds have increased, while planned flare events that exceeded those thresholds have been constant in frequency during the same period of time.

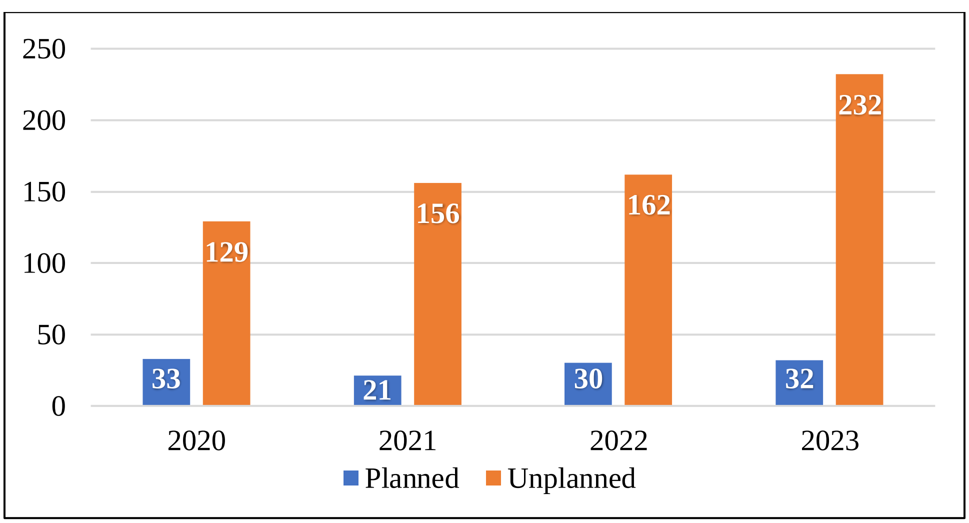


Figure 2-13. Count of Flare Events Reported on FENS (Planned vs. Unplanned)

Almost half of the flare events reported on FENS did not exceed the established Rule 1118 thresholds. These flare events are flare events, mainly unplanned (98 percent), that were required to be reported through FENS for exceeding the daily cumulative vent gas flow threshold of 100,000 standard cubic feet. The figure below shows the share of planned and unplanned flare events out of the flare events that exceeded at least one of the Rule 1118 thresholds.

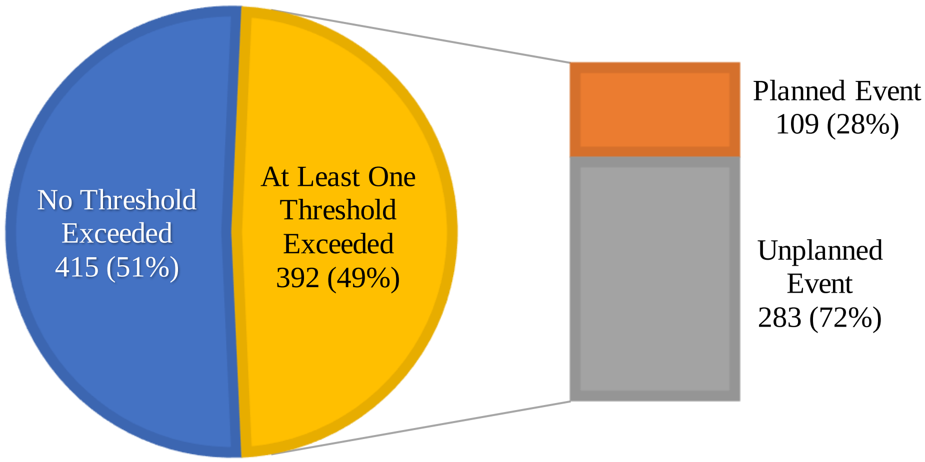


Figure 2-14. Distribution of Flare Events by Type

The figure below shows the count distribution of flare events (planned or unplanned) reported on FENS since 2020 that exceeded the established Rule 1118 thresholds. Different categories are not exclusive and there are flare events that exceeded more than one threshold for the entire flare event. Data shows an increase between 2020 and 2023 in the count of flare events that exceeded the threshold of "500,000 standard cubic feet of total vent gas", but the count of flare events that exceeded the threshold of "500 pounds of SO_2 emissions" shows a decreasing trend.

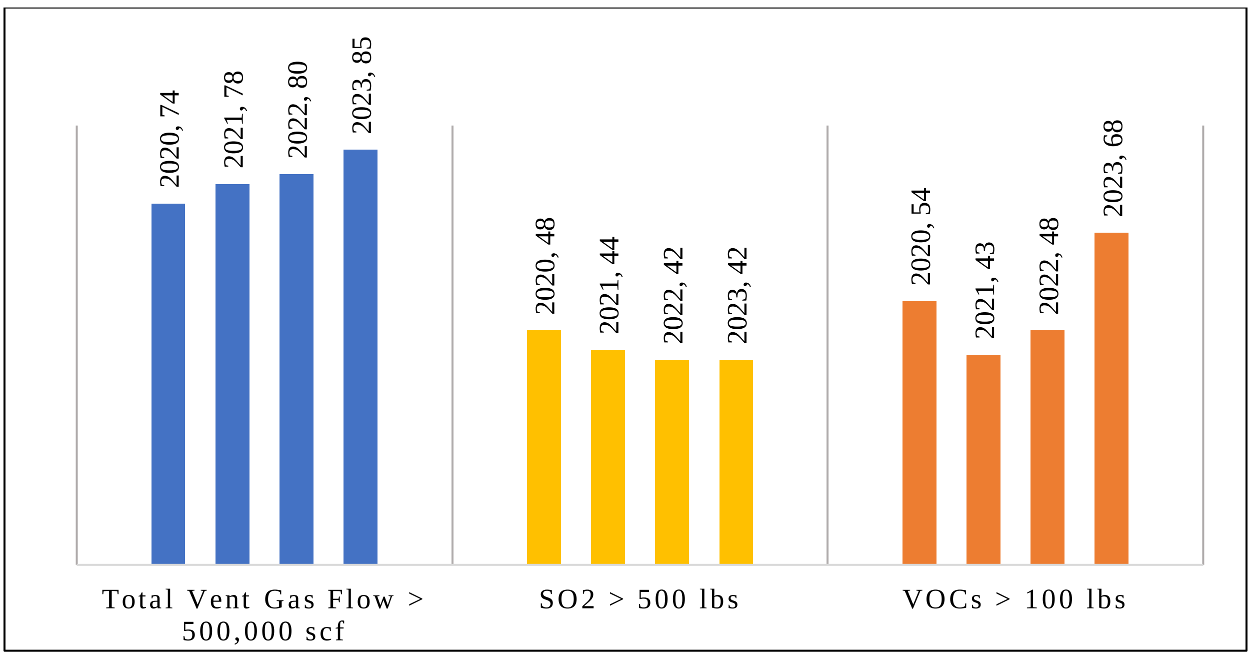


Figure 2-15. Count Distribution of Reported Flare Events on FENS by Rule Thresholds

SCOPING DOCUMENTS

As part of 2017 amendments to Rule 1118, owners and operators of all facilities were required to submit a Scoping Document within 12 months of the rule amendment. Facility operators and owners were required to evaluate technical feasibility, approximate cost, and timing constraints to implement control options for minimizing or avoiding planned and unplanned flaring events. In addition, facility operators had to evaluate two potential alternatives for emission reductions from flaring during planned flare events at each of the following performance targets:

- 0.10 ton of SO_2 per million barrels of crude processing capacity
- 0.05 ton of SO_2 per million barrels of crude processing capacity
- 0.01 or less ton of SO_2 per million barrels of crude processing capacity
- 0.1 ton of VOC per year from clean service flares

Operators of facilities also had to evaluate emission reductions from flaring for four scenarios of unplanned flare event:

- Sudden influx of vent gas into the flare gas header
- Sudden loss of the process unit with the highest fuel gas consumption rate of recovered flare gas
- Sudden loss of all externally generated electrical power
- Sudden loss of internally generated electrical power

Hydrogen Production Plants

Operators of hydrogen production plants indicated the measures in scoping plans to reduce flaring, as listed in the following table.

Table 2-4. Measures to Reduce Emissions from Flaring at Hydrogen Production Plants

<table>
<tr><th>Actions</th><th>Notes</th></tr>
<tr><td>Minimizing emergency flaring through eliminating the sources of plant tripping
• Addition or removal of specific instruments or equipment
• Proper operation/maintenance of specific instruments or equipment</td><td rowspan="4">One hydrogen production plant is implementing most of these actions already</td></tr>
<tr><td>Operate the plant with an uninterrupted power</td></tr>
<tr><td>Limit the duration of planned shutdown event and planned startup event</td></tr>
<tr><td>Use the hot restart operating procedure in the event of a plant shutdown following a process upset to temporarily maintain normal operating temperature in the heater when condition allows</td></tr>
<tr><td>Installation of flare gas recovery system and gas turbine generator which would reduce planned and unplanned events
• Estimated capital cost: $50 million – $100 million
• Estimated operational cost: $20 million – $65 million per year (reflecting savings from reduced power demand)</td><td rowspan="2">Actions identified by the facilities as being costly or economically infeasible</td></tr>
<tr><td>Pressurize gases and place into on-site storage containers which may not be a feasible alternative due to safety concerns, physical plot space availability, and significant operational complexities
• Project implementation cost: $50 million – $100 million</td></tr>
</table>

Facilities Other Than Hydrogen Production Plants

Operators of facilities other than hydrogen production plants identified a number of actions in scoping documents to reduce planned and unplanned flaring and related emissions. Several of the listed actions are already being implemented at these facilities, such as training staff, managing flare gas, planning turnarounds, maintaining equipment, etc. Facility operators listed actions that could be most impactful to be very costly, e.g., flare gas recovery with gas turbine which was listed to cost between $50 million and $100 million.

The identified potential alternatives in the scoping documents for emission reductions from flaring during planned flare events occurring at facilities other than hydrogen production plants can be categorized into three main categories, as presented in the following table.

Table 2-5. Measures to Reduce Emissions from Planned Flare Events at Facilities Other Than Hydrogen Production Plants

Actions	Notes
Emission Monitoring Enhancements	
Modify existing flare header flow meters to more accurately measure low molecular weight gas	Better to characterize and measure the flow gas, not for specific emission reductions. Staff is proposing to include additional requirement for flow meters.
Install new/additional flow meters	
New HHV analyzer for faster response time	
Modify flare water seal settings	
Source Control Modifications	
Develop planned turnarounds and perform critical maintenance during turnarounds	Refineries implementing most of these actions already
Capture lessons learned from flaring events with continuous improvement	
Operator training and developing a mindset for minimum flaring	
Evaluate root cause of all unplanned flaring events and propose corrective actions to minimize these events in the future	
Modify Operating Procedure for startup, shutdown, and clean service flare	
Use modified operating procedures and work practices to mitigate flaring	
Reduce plant feed rates which will reduce the amount of vent gas flared	Facilities could use this approach to reduce flare emissions below performance thresholds
Tail End Control Enhancements	
Modify reliability of flare gas recovery compressors	Refineries implementing most of these actions already
Keep spare equipment in optimal running condition	
Planning/managing the shutdown/startup activities to effectively manage the available vapor recovery capacity	
Use rental vapor/gas recovery equipment	Facilities could use these approaches to reduce flare emissions below performance thresholds
Use of temporary portable condensing system or sulfur scrubbing system	

The table below includes the identified potential alternatives in the scoping documents for emission reductions from flaring during unplanned flare events occurring at facilities other than hydrogen production plants.

Table 2-6. Control Measures to Reduce Emissions from Unplanned Flare Events at Facilities Other Than Hydrogen Production Plants

Actions	Notes
A sudden influx of vent gas into a flare gas header	
• Maximize operation of the Vapor Recovery System • Use of spare Flare Gas Recovery equipment • Improve reliability of process equipment	Refineries implementing most of these actions already
• Balance production and use of fuel gas at the refinery to minimize instances where excess fuel gas must be flared • Automate the reduction of feed rate to the lower priority process units • Reduce flaring by increasing fuel gas consumption to units within the plant • Export excess fuel gas to third party to relieve pressure	Facilities could use these approaches to reduce flare emissions below performance thresholds
A sudden loss of the process unit with the highest fuel gas consumption rate of recovered flare gas at that facility	
• Maximize operation of the Vapor Recovery System • Use of spare Flare Gas Recovery equipment • Improve reliability of process equipment • Automation of using spare equipment (if available)	Refineries implementing most of these actions already
• Balance production and use of fuel gas at the refinery to minimize instances where excess fuel gas must be flared • Automate the reduction of feed rate to the lower priority process units • Export excess fuel gas to a third party to relieve pressure	Facilities could use these approaches to reduce flare emissions below performance thresholds
Loss of all external electrical power to the facility	
• Operate Cogeneration Unit • Install and use independent underground power feeders • Reduce feed rates to lower priority process units • Reduce power production of the cogeneration unit	Facilities could use these approaches to reduce flare emissions below performance thresholds
• Import electricity from a Third Party • Switch to Secondary External Feeder	Included in one refinery’s scoping plan; already implemented
A sudden loss of all electrical power from any non-backup electrical generation unit currently operating at the facility	
• Import electricity from a Third Party • Control mechanism to automatically receive power from local power supplier	Included in one refinery’s scoping plan; already implemented

Staff considered the information supplied in the scoping documents as well as staff's technical assessment during the rule development process. Chapter 3 details the proposed changes to Rule 1118 to reduce flare emissions.

CHAPTER 3 : EMISSIONS CONTROLS ASSESSMENT

PERFORMANCE TARGET ASSESSMENT

CONTROL OF EMISSIONS AT CLEAN SERVICE FLARES

PAR 1118 AND AB 617 CERP ACTIONS

PERFORMANCE TARGET ASSESSMENT

The SO_2 performance target was included in the 2005 amendment to Rule 1118. It required the owners and operators of petroleum refineries to comply with a declining annual SO_2 performance target. The SO_2 target was gradually reduced over a six-year period as shown in the table below. The current version of Rule 1118 includes a performance target for SO_2 emissions at 0.5 ton per million barrels (MMbbl) of crude processing capacity (averaged over one calendar year). If the performance target is exceeded, the facility owner or operator is required to submit a flare minimization plan (FMP) and pay mitigation fees.

Table 3-1. Gradually Decreasing Annual SO_2 Performance Target Since 2006

Facility	Crude Oil Capacity (2004) (Million Barrels)	Facility Specific SO_2 Performance Target (ton/yr)			
		2006 Target 1.5 tons/MMbbl	2008 Target 1.0 ton/MMbbl	2010 Target 0.7 ton/MMbbl	2012 Target 0.5 ton/MMbbl
AltAir Paramount	18.3	27.5	18.3	12.8	9.2
Chevron USA Inc.	95.2	142.7	95.2	66.6	47.6
Marathon Carson	95.2	142.7	95.2	66.6	47.6
Marathon Wilmington & SRP	36.1	54.1	36.1	25.2	18.0
Phillips 66	50.9	76.3	50.9	35.6	25.4
Torrance Refining Co.	54.7	82.1	54.7	38.3	27.4
Valero	29.6	44.4	29.6	20.7	14.8
Total	**379.9**	**569.8**	**380.0**	**265.8**	**190.0**

Mitigation fees are determined based on the percent of emissions in excess of facility-specific performance target, using the following equation:

$$\begin{aligned} &Facility\ Specific\ Performance\ Target\ [Tons\ of\ SO_2] \\ &= Performance\ Target\ \left[\frac{Tons\ of\ SO_2}{Million\ Barrels}\right] \\ &\times Crude\ Processing\ Capacity\ [Million\ Barrels] \end{aligned}$$

In the current version of Rule 1118, facility specific SO_2 performance target is calculated based on a facility's 2004 crude processing capacity. The list of facilities' processing capacity is publicly available on California Energy Commission's (CEC) website.[2] Processing capacity for most refineries has not changed since 2004, but two facilities have had operational changes:

[2] California Energy Commission – California's Oil Refineries Locations and Capacities: https://www.energy.ca.gov/data-reports/energy-almanac/californias-petroleum-market/californias-oil-refineries

- AltAir (World Energy) transitioned from crude oil to alternative feedstocks and decreased capacity from 18.3 MMbbl/yr to 1.3 MMbbl/yr but plans to increase capacity in the coming years.
- Marathon integrated the operations of their Wilmington and Carson refineries.

Staff is proposing to lower the SO_2 performance target in two steps, to 0.35 ton per million barrels of processing capacity for the 2025 calendar year and to 0.25 ton per million barrels of processing capacity for the 2026 calendar year. Facility specific SO_2 performance targets are listed in the table below for each proposed phase. This proposed change will in part satisfy the AB 617 CERP requirement to achieve 50 percent reduction in flaring emissions in Rule 1118. Lowering the SO_2 performance target will result in more frequently submitted FMPs and additional mitigation fees paid by the owners or operators of facilities. Staff has documented decreases in facility flaring and flare emissions in the year following a year where a facility exceeds the performance threshold. Staff attributes this reduction to the facility evaluating their operations through the FMP and removal of the $4 MM cap for mitigation fees as part of the 2017 amendments. Removing the mitigation fee cap and increasing mitigation fees served as a deterrent to flaring and incentivize facilities to minimize flaring emissions.

Table 3-2. Proposed Gradually Decreasing Annual SO_2 Performance Target

Facility	Crude Oil Capacity (2023) (Million Barrels)	Facility Specific SO_2 Performance Target (ton/yr)		
		2012 Target 0.5 ton/MMbbl	2026 Proposed Target 0.35 ton/MMbbl	2028 Proposed Target 0.25 ton/MMbbl
AltAir Paramount	1.3	9.2	0.4	0.3
Chevron USA Inc.	98.2	47.6	34.4	24.5
Marathon Carson	98.3	47.6	46.5	33.2
Marathon Wilmington & SRP	34.6	18.0		
Phillips 66	50.7	25.4	17.8	12.7
Torrance Refining Co.	55.1	27.4	19.3	13.8
Valero	31.0	14.8	10.9	7.8
Total	**379.9**	**190.0**	**135.6**	**96.9**

The level of SO_2 emissions per processing capacity is listed in the table below for all refineries regulated by PAR 1118. Staff used the data reported by the refineries in the submitted quarterly reports by each facility during the past decade in compliance with Rule 1118. Red cells in the table indicate the facility-years when the current SO_2 performance target of 0.5 ton per million barrels of processing capacity were exceeded. Yellow cells in the table indicate the facility-years when the current SO_2 performance target of 0.5 ton per million barrels of processing capacity was not exceeded, but the proposed SO_2 performance target of 0.25 ton per million barrels of processing capacity would be exceeded.

According to the table below, a SO_2 performance target of 0.25 ton per million barrels of processing capacity is achieved in practice at four out of seven crude oil processing refineries since 2017. Associated costs with reducing emissions are expected to be mainly due to the changes to the operational practices.

Table 3-3. SO_2 Emissions per Processing Capacity by Refinery

Year	Chevron	Marathon Wilmington & SRP	Marathon Carson	AltAir Paramount	Valero	TORC	Phillips 66
2012	0.11	0.59	0.02	0.001	0.48	0.80	0.61
2013	0.29	0.07	0.06	0.000	0.21	0.40	0.31
2014	0.29	0.04	0.00	0.000	0.54	0.50	0.57
2015	0.23	0.01	0.03	0.003	0.13	1.90	0.91
2016	0.13	0.08	0.01	0.001	0.63	0.30	0.30
2017	0.00	0.17	0.02	0.001	0.15	0.70	0.30
2018	0.11	0.01	0.03	0.001	0.01	0.20	0.74
2019	0.07	0.43	0.02	0.000	0.01	0.20	0.47
2020	0.03	0.06	0.08	0.001	1.10	0.11	0.20
2021	0.16	0.64	0.06	0.001	0.51	0.10	1.02

The cost-effectiveness analysis completed for PAR 1118 did not include an analysis for the proposed SO_2 performance target. Establishing a performance target is not the same as establishing BARCT emission limits and is different than imposing a control requirement. A performance target provides the facility with inherent flexibility to pursue the most cost-effective options available to that facility and does not require prescriptive controls that are able to be quantified. Therefore, a cost-effectiveness analysis is not required. Moreover, every facility is unique in their operation, arrangement, and physical layout, so analyzing the availability or cost-effectiveness of alternatives, and identifying a range of probable costs, is not applicable to a target established by means of a proposed performance standard. Facilities will likely work to stay below the performance target by implementing process or operational changes specific to each facility which cannot be quantified at this time.

Mitigation Fees

Facilities that exceed SO_2 performance target must pay mitigation fees, determined based on the percent of emissions in excess of facility-specific performance target, according to the schedule in the table below.

Table 3-4. Mitigation Fees for Exceeding SO_2 Performance Target

Excess Emissions (%)	Mitigation Fees ($/ton of Excess SO_2)
≤10	25,000
>10 to ≤20	50,000
>20	100,000

All flare emissions, except for those caused by external power curtailment beyond the operator's control (excluding interruptible service agreements), natural disasters or acts of war or terrorism, are subject to this mitigation fee if a facility's SO_2 emissions exceed the SO_2 performance target. Rule 1118 current mitigation fees were established in, and have not changed since, 2004. The rule used to include an annual cap of $4 million; however, as part of the 2017 amendment to Rule 1118, the $4 million annual cap on mitigation fees was removed.

This mitigation fund can only be spent with authorization from the South Coast AQMD Governing Board. Historically, mitigation fees have been used for certain emission reduction incentive programs, such as port of Long Beach zero-emission and hybrid terminal equipment deployment and demonstration project, zero-emission, and clean energy demonstration projects, etc. Programs for spending these mitigation fees are developed outside of this rule amendment process.

CONTROL OF EMISSIONS FOR CLEAN SERVICE FLARES

Clean service streams are low in level of sulfur content. In general, there are two categories of clean service flares regulated under PAR 1118:

- Hydrogen clean service flares
- Non-hydrogen clean service flares which include liquified petroleum gas (LPG) flares.

Hydrogen Clean Service Flares

Hydrogen clean service flares are control devices for the vent gas stream generated during normal and abnormal operations at hydrogen production plants and due to hydrogen kick-back by customer. Vent gas stream composition is primarily hydrogen, methane, nitrogen, and carbon dioxide.

Hydrogen clean service flares are subject to the Rule 1118 SO_2 performance target, but the vent gas streams to these flares have very low sulfur content. As a result, the requirements for an FMP submission and payment of mitigation fees have never been triggered for any of the hydrogen production plants; therefore, no flare minimization actions have been taken at hydrogen clean service flares to reduce SO_2 emissions.

All flares, including clean service flares, are a significant source of NOx emissions. NOx emissions are the most significant precursor of ground level ozone formation and the South Coast AQMD must reduce these emissions wherever feasible. South Coast AQMD previously adopted Rule 1118.1 in 2019 with the purpose to reduce flaring and flare emissions, specifically NOx emissions, from non-refinery flares.

For the hydrogen clean service flares subject to Rule 1118, NOx emissions have ranged from zero to 0.37 pounds per hydrogen production capacity (lbs/MMscf) over the last ten years and the emission vary based on operational needs and unit maintenance. Staff proposes to establish an annual NOx performance target to control NOx emissions from hydrogen clean service flares. The proposed NOx performance target is 0.3 pound per million standard cubic feet (MMscf) of the facility's hydrogen production capacity.

The cost-effectiveness analysis completed for PAR 1118 did not include an analysis for the proposed NOx performance target. Establishing a performance target is not the same as establishing BARCT emission limits and is different than imposing a control requirement. A performance target provides the facility with inherent flexibility to pursue the most cost-effective options available to that facility and does not require prescriptive controls that are able to be quantified. Therefore, a cost-effectiveness analysis is not required. Moreover, every facility is unique in their operation, arrangement, and physical layout, so analyzing the availability or cost-effectiveness of alternatives, and identifying a range of probable costs, is not applicable to a target established by means of a proposed performance standard. Facilities will likely work to stay below the performance target by implementing process or operational changes specific to each facility which cannot be quantified at this time.

Non-Hydrogen Clean Service Flares (LPG Flares)

LPG flares are categorized as non-hydrogen clean service flares and are dedicated to the LPG storage or loading areas of refinery. These flares serve as control devices to control LPG vapors and large emergency release of LPG vent gas streams. LPG flares primarily combust vent gas from LPG storage tanks which is mainly composed of propane and/or butane. Non-hydrogen clean service flares regulated under PAR 1118 are located at three refineries in storage areas (tank terminals) and the majority of them are not integrated with refinery vapor recovery system. Flaring at LPG flares occurs when LPG vapor is relieved from pressure control valves or pressure safety valves (PSV) of storage tanks/vessels, when the LPG tanks/vessels are being de-inventoried for cleaning or inspection, and during turnaround maintenance.

Figure 3-1. Non-Hydrogen Clean Service Flare (LPG Flare)

Recovering LPG from non-hydrogen clean service flares is technically feasible and cost-effective. Two out of three refineries regulated by PAR 1118 have large amounts of flaring due to the continuous venting of gas streams from LPG tanks to non-hydrogen clean service flares. The flaring from the non-hydrogen clean service flares may account for a majority of vent gas flow rate of total refinery flaring (historically as high as 90 percent per facility in a single year). One refinery uses a refrigeration/chiller system to minimize flaring of LPG vent gas streams. This system reduces, but does not eliminate, LPG flaring, as flaring still occurs during LPG tank clean-up and emergency release situations. The table below lists three Rule 1118 facilities that operate LPG clean service flares and the annually recorded throughput for each flare (2017 to 2021).

Table 3-5. Annual Throughput (MMBtu/year) for Non-Hydrogen Clean Service Flares

Year	Phillips 66	Torrance	Valero
2017	58,627	2,200	80,656
2018	33,307	488	62,820
2019	34,600	13,140	86,730
2020	45,013	981	95,244
2021	40,400	225	78,411

Non-hydrogen clean service flares are similar to certain type of flares subject to Rule 1118.1 (i.e., flares located at tank terminals). Rule 1118.1 regulates NOx and VOC emissions from non-refinery flares located at landfills, wastewater treatment plants, oil and gas production facilities, organic liquid loading stations, and tank terminals. Flares regulated by Rule 1118.1 that operate at greater than a specified capacity threshold are required to, either reduce the level of flaring to below the capacity threshold (e.g., through beneficial use strategies), or replace the flare with a unit complying with the lower NOx emission limits (ultra-low NOx flares).

Vent gas streams to LPG flares are low in sulfur, but combustion of such gas stream generates NOx emissions. Staff proposed a similar approach to Rule 1118.1 to establish a throughput threshold to minimize flaring from LPG flares. Reducing flare throughput reduces NOx emissions; however, directing vent gas streams from LPG tanks to the refinery vapor recovery system is challenging and costly, because the LPG tank is located far from the refinery vapor recovery system. That option was assessed by a refinery in their scoping plans but was eliminated as an infeasible option due to the high costs. The feasible option is to recover the LPG stream and recycle it back to the LPG storage tank itself. Also, LPG is a valuable commodity that can be recovered and sold rather than being combusted in a flare, which will result in some cost savings.

Staff calculated a throughput threshold in MMBtu per year where installing an auxiliary gas refrigeration/compression system becomes cost-effective. This throughput threshold can be used to trigger facilities to take actions to reduce faring emissions at non-hydrogen clean service flares. That assessment is detailed below.

Technology Assessment

Staff's evaluation concluded that a refrigeration/chiller system is the most effective technology to minimize or eliminate the continuous flaring occurring at the existing LPG flares. The technology is proven and achieved in practice since one refinery that is currently subject to the rule has already implemented and operates a refrigeration/chiller system which effectively recovers nearly all the LPG that would otherwise be burned at the flare. The auxiliary refrigeration/chiller system used for recovery of vent gas streams from LPG tanks and control of emissions from LPG flares is comprised of:

- Major equipment
- Compressor with motor and drive package
- Condenser
- Structural base

- Piping
- Insulation
- Control system
- Electrical conduit and upgrades
- Engineering and design
- Installation

The refrigeration/chiller system requires additional electricity to operate which adds to the operating cost – the primary electrical consumer of the system is the compressor. However, butane/propane is a valuable commodity for the refinery and the recovered gas can be sold and generate additional revenue and offset the cost of the required energy. The generated profit is estimated to be approximately $190,000 per year.

One facility indicated that they may elect to replace their existing LPG flare system with a newer design in order to reduce or eliminate the amount of LPG continually being vented. The facility indicated that the system is equipped with a single totalizing flow meter and a majority of the gas combusted is attributed to the purge gas and not vent gas. The decision to potentially replace the LPG flare is due to the existing design of the current LPG flare system which requires a large purge flow rate to maintain the velocity/positive pressure, which is essential to prevent air intrusion into the system. A new flare system may consist of:

- Elevated flare – self supported 100 feet overall height rated for 500,000 pounds per hour (lb/hr) with carbon steel stack and utility tips and pilots
- Ignition system with automatic relight, pilot status monitors, sun/rain shield
- Utility piping/wire for pilot gas, ignition lines, conduit, thermal couple wire
- Corrosion protection with epoxy paint finish
- Structural base
- Engineering and design
- Installation

Unlike the chiller/refrigeration option, the new flare will not result in additional annual operating costs since a refrigerant compressor system is not necessary. However, the facility can generate additional revenue since the LPG can be sold rather than burned as waste. The estimated generated profit is approximately $392,000 per year.

Cost-Effectiveness Analysis

South Coast AQMD routinely conducts cost-effectiveness analyses regarding proposed rules and regulations that result in the reduction of criteria pollutants (NOx, SOx, VOC, PM, and CO). The analysis is used as a measure of effectiveness of the proposed control technologies and to measure the relative cost of more stringent controls. It is generally used to compare and rank rules, control measures, or alternative means of emissions control relating to the cost of purchasing, installing, and operating control equipment to achieve the projected emission reductions. The major components of the cost-effectiveness analysis are capital and installation costs, operating and maintenance costs, emission reductions, discount rate, and equipment life. The cost-effectiveness analysis for PAR 1118 was completed for each proposed amendment (except for the proposed SO_2 and NOx performance targets) using the discounted cash flow method explained below.

Discounted Cash Flow (DCF)

The DCF method converts all costs, including initial capital investments and costs expected to be incurred in the present and all future years of equipment life, to present value. Conceptually, it is as if calculating the number of funds that would be needed at the beginning of the initial year to finance the initial capital investments and to be set aside to pay off the annual costs as they occur in the future. The fund that is set aside is assumed to be invested and generates a rate of return at the discount rate chosen. The final cost-effective measure is derived by dividing the present value of total costs by the total emissions reduced over the equipment life. The equation below is used for calculating cost-effectiveness with DCF. The equation was presented in the 2016 AQMP Socioeconomic Report Appendix 2-B (p. 2-B-3).

$$\text{Cost} - \text{Effectiveness} = \frac{\text{Initial Capital Investments} + (\text{Annual O\&M Costs} \times \text{PVF})}{\text{Annual Emission Reductions} \times \text{Years of Equipment Life}}$$

Where:

$$\text{PVF} = \frac{(1+\text{r})^{\text{N}} - 1}{\text{r} \times (1+\text{r})^{\text{N}}}$$

Where:

r = real interest rate (discount rate)
N = years of equipment life

Cost-Effectiveness Screening Threshold

The South Coast AQMD Governing Board adopted the 2022 AQMP on December 2, 2022, which establishes a new cost-effectiveness screening threshold of $325,000 per ton of NOx reduced. The new threshold utilizes a health-based approach and uses a public health monetized benefit value for reducing pollution. This is a similar approach to the one used by CARB and U.S. EPA where the associated costs with a rule are compared to the monetized benefits associated with the resulting emission reductions. The $325,000 threshold was based on U.S. EPA established monetized benefit value of $307,636 and 2016 AQMP monetized benefit value of $342,000 per ton of NOx reduced. The 2022 AQMP states that the benefits-based screening threshold of $325,000 would be inflated through time to the dollar-year used in the control measure-specific socioeconomic analysis. The screening threshold will be inflated using the annual California Consumer Price Index (CPI) for consistency with how the benefits-based threshold was inflated to 2021-dollars in the 2022 AQMP and 2022 AQMP socioeconomic report. Using CPI is more appropriate than using the Marshall & Swift Index, because the screening threshold is health-benefits based. The inflation-adjusted screening threshold is not conducted for every rulemaking but rather annually based on the year the costs are brought into analysis. In the case of PAR 1118, the cost used in the assessment was based on 2022-dollars and the health-based screening threshold of $325,000 was based on 2021-dollars. The screening cost-effectiveness threshold was adjusted from 2021-dollars to 2022-dollar year using the CPI for 2022 and 2021, as stated below.

$$\begin{aligned}\text{Inflation Adjusted Threshold in 2022} &= \text{Threshold in 2021} \times \left(\frac{\text{CPI in 2022}}{\text{CPI in 2021}}\right) \\ &= \$325{,}000 \times \left(\frac{319.224}{297.371}\right) \\ &= \$349{,}000\end{aligned}$$

The adjusted cost-effectiveness screening threshold in 2022-dollars is $349,000 per ton of NOx reduce which is $24,000 higher than the $325,000 threshold in the 2022 AQMP.

Summary of Cost Data and Assumptions

To determine cost-effectiveness for the proposed throughput threshold for non-hydrogen clean service flares, cost information and estimates for the control equipment were obtained. Staff gathered cost data and estimates for refrigeration compressor system, piping, instrumentation, structural steel, electrical upgrade, and engineering design. In addition, staff reached out to the affected facilities to gather equipment data and cost information for potential NOx control projects. One facility provided staff with project scope estimates that was conducted in 2019 by an engineering firm. Also, staff used a 25-year equipment life in calculating the cost-effectiveness of the control option.

Butane/Propane is a valuable commodity that can be recovered rather than disposing in flare and the generated revenue can be contributed to offset cost of regulatory compliance. Staff estimated the revenue from the recovery and sale of butane/propane to be realized up to approximately $392,000 per year (assuming 0.71 cents per gallon[3] for recovered propane at 65,000 standard cubic feet per day).

Compressor for refrigeration unit also requires additional electricity and staff assumed the industrial electricity rate of 0.21 cents per kilowatt-hour[4] to calculate the cost of required electricity.

Cost Estimates for The Auxiliary Gas Refrigeration/Compression System

Cost estimates for the auxiliary gas refrigeration/chiller system were provided from vendors and facilities. Vendor cost estimates included compressor (150 hp) and condenser costs. Facility-provided cost estimates included the cost to send the recovered LPG gas to the vapor recovery system and process units. Staff incorporated the cost for piping, structural base, control system, instrumentation, panels, fireproofing, and insulation based on the cost estimates provided by the facility; these costs were incorporated into the cost evaluation as part of major equipment costs. For installation cost, staff assumed the cost to be equivalent to the capital/major equipment costs, however staff also included an additional 20 percent to the installation costs due to Senate Bill 54 which requires refineries to hire unionized labor. Staff adjusted cost estimates provided by the facility using CPI for 2022-dollar year and calculated the total installed equipment cost of approximately $10.5 MM:

- Major equipment costs: $2.5 MM
- Electrical upgrades: $1.8 MM
- Installation costs: $3 MM (1.2x major equipment costs)
- Engineering costs: $3.1 MM

Annual O&M Costs

- Annual electricity costs: ~$206,000

[3] U.S. Energy Information Administration - EIA – Independent Statistics and Analysis: https://www.eia.gov/todayinenergy/prices.php

[4] U.S. Energy Information Administration - EIA – Monthly Table: Electric Power Monthly - U.S. Energy Information Administration (EIA)

LPG Recovery Revenue

- Butane/Propane revenue: ~$392,000

Annual and Lifetime Cost Savings

- Annual cost savings: ~$187,000
- Lifetime cost savings: ~$4.7 MM

Cost Estimates for New LPG Flare

Vendors provided a budgetary quote for a new elevated flare, self-supported 100 feet overall height, rated for 500,000 pounds per hour (lb/hr), and with a carbon steel stack. The flare cost also includes utility tips, pilot, ignition system with automatic relight, pilot status monitors, sun/rain shield, utility piping/wire for pilot gas, ignition lines, conduit, and thermal couple wire. Since the flare is elevated, staff also considered the cost of a structural base and foundation to withstand seismic activity. Staff incorporated the cost piping and additional instrumentation based on facility provided estimate. For installation cost, staff assumed the cost to be equivalent to the capital/major equipment costs plus an additional 20 percent to account for Senate Bill 54 which requires refineries to hire unionized labor. The estimated total installed cost for a new LPG flare is approximately $10 MM

- Major equipment costs: $3.2 MM
- Installation costs: $3.8 MM (1.2x major equipment costs)
- Engineering costs: $3.0 MM

Annual O&M Costs

- No additional O&M Costs: $0

LPG Recovery Revenue

- Butane/Propane revenue: ~$392,000

Annual and Lifetime Cost Savings

- Annual cost savings: ~$392,000
- Lifetime cost savings: ~$9.8 MM

Cost-Effectiveness Calculations

To calculate the cost-effectiveness, staff excluded the facility with an existing LPG recovery system in place. For the remaining two facilities, staff assumed one facility will install a refrigeration/chiller system and the other facility will install a new LPG flare. Cost-effectiveness calculations accounted for NOx emissions reductions only, but there will be additional co-benefits of reduced VOC and PM emissions. NOx emissions are calculated using the NOx emission factor as listed in PAR 1118 and as a result, the larger the LPG vent gas volume the higher NOx emissions. Staff used NOx emissions data averaged over a five-year period (2017 to 2021) as a baseline to account for operational variation in NOx emissions year-to-year and assumed a 90 percent reduction of flaring NOx emissions to be realized through the auxiliary gas refrigeration/compression system.

Staff evaluated the minimum annual throughput at which LPG recovery was cost-effective to be equal to 15,000 MMBtu per year. Cost-effectiveness was calculated to be $58,000 per ton of NOx reduced over the lifetime of the auxiliary gas refrigeration/compressor system or new flare, which is well below the cost-effectiveness threshold of $349,000 per ton of NOx reduced as established by 2022 AQMP. The annual throughput of 15,000 MMBtu per year or greater is below the cost-effectiveness threshold of $349,000 per ton of NOx reduced.

Staff proposing requirements to require any facility that exceeded an annual throughput exceeds 15,000 MMBtu/year for two consecutive years since 2017 to reduce flaring at non-hydrogen clean service flares (LPG flares). This proposal will impact two facilities and will require those facilities to implement corrective actions.

Estimated Emissions Impact

Staff estimated the corresponding lifetime NOx emission reductions from implementation of auxiliary gas refrigeration/compressor system at two facilities that operate LPG flares to be equal to 7.3 ton per year at the throughput threshold of 15,000 MMBtu per year for LPG flares.

PAR 1118 and AB 617 CERP Actions for Wilmington, Carson, West Long Beach Community

Staff aligned the proposed requirements under PAR 1118 with the AB 617 CERP actions for the Wilmington, Carson, West Long Beach community. The table below shows the requirements and considerations by PAR 1118 that address the listed actions by AB 617 CERP.

Table 3-6. PAR 1118 Impacts on AB 617 CERP Actions for Wilmington, Carson, West Long Beach Community

AB 617 CERP Actions	PAR 1118 Related Impact(s)
Lower performance targets and/or increase mitigation fees	- Proposing to lower SO_2 performance target - Proposing to increase mitigation fees using Customer Price Index
Additional flare minimization plans	- Lowered performance target would trigger FMP submittals more frequently
Lower-emission flaring technologies	- Flare manufacturers improve design, efficiency, and performance - Facilities replace and upgrade in accordance with turnaround - More frequent FMPs would trigger actions that may include replacement of flare components
Back-up power systems for key process units	- More frequent FMPs would trigger actions that reduce flaring due to internal power loss - According to SCARs, power failures mainly result from electrical switch failures, transformer ground faults, blown fuse, short circuits, and animal intrusions

PAR 1118 fulfills most of the priority actions included in the AB 617 CERP for the Wilmington, Carson, West Long Beach community; however, staff determined some of the actions as not to be technically feasible, as stated below.

Action Item: Increase Capacity of Vapor Recovery Systems to Store Gas During Shutdowns

Recovered vent gas by vapor recovery system is not intended to be stored as large volume of stored gas can create an explosive environment. All refineries have FGR systems designed to capture a designed volume of the vent gas that would otherwise be combusted in the existing flare equipment, but use of large storage systems was deemed to be infeasible.

Action Item: Header Modifications for Gas Diversion with Process Controls

Owners and operators of facilities implemented modification of flares header as part of the requirements by 2005 amendments to Rule 1118 by installing or upgrading flare gas recovery systems. Staff did not identify any emission reductions that could feasibly be achieved with header modifications.

Action Item: Remote Optical Sensing for Flare Emission Characterization

Video Imaging Spectro-Radiometry (VISR) technology is commercially available and there are technology vendors that provide this technology for the purpose of remote optical sensing. However, technologies that work with VISR method are currently under review by U.S. EPA but not yet approved. Staff will consider these technologies for the purpose of flare emissions characterization or as a tool for South Coast AQMD compliance staff to verify flare emissions in the future when the technology is approved by U.S. EPA.

CHAPTER 4 : SUMMARY OF PROPOSALS

INTRODUCTION

The main objective of PAR 1118 is to reduce emissions from refinery flares by lowering the SO_2 performance target for general service flares, establish a new NOx performance target for hydrogen production plants, and establish a throughput threshold for LPG clean service flares. The proposed amendments and projected emission reductions are aligned with the emission reduction targets that were included in the Wilmington, Carson, West Long Beach CERP and are expected to be achieved by 2030. PAR 1118 also removes outdated rule language, reorganizes the rule structure to be consistent with recently amended or adopted rules, and includes separate and new requirements for clean service flares located at refineries and hydrogen production plants, updates requirements for notifications sent through FENS, and establishes new requirements for standardized flare event data reporting through FENS.

Staff initially considered requiring the owner or operator of facilities to post live flare images on FENS or another public webpage as part of PAR 1118. However, due to security concerns with respect to the applicability of security provisions related to the facilities subject to Rule 1118 under the Chemical Facility Anti-Terrorism Standards (CFATS) administrated by the federal Cybersecurity and Infrastructure Security Agency (CISA) and the US Coast Guard, staff withdrew the proposal to ensure PAR 1118 is consistent and not contradictory to existing orders, state law, and federal requirements.

PROPOSED AMENDED RULE STRUCTURE

In PAR 1118, staff separated the purpose and applicability to be consistent with recently adopted and amended rules by South Coast AQMD and added new subdivisions to support the rule requirements.

PAR 1118 has two new subdivisions and two new attachments. Staff clarified and streamlined rule language and consolidated rule provisions. PAR 1118 has new and separate requirements for hydrogen and non-hydrogen clean service flares. The following figure compares the rule structure of the 2023 Rule 1118 (last amendment) versus PAR 1118.

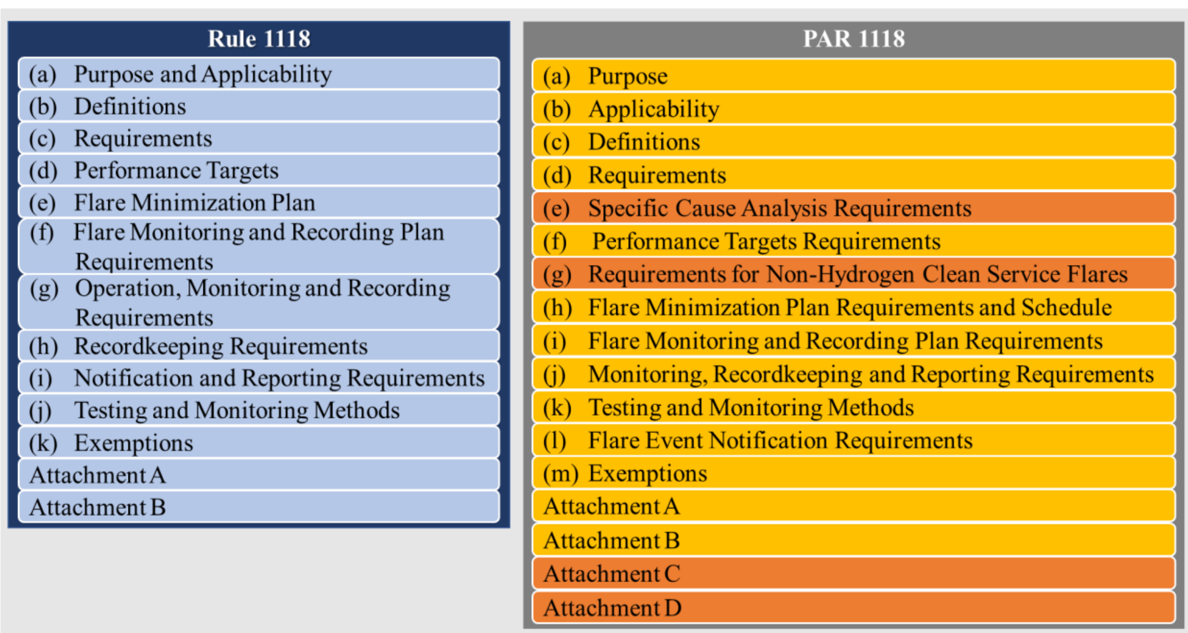


Figure 4-1. Rule Structure – Rule 1118 vs. PAR 1118

SUMMARY OF PROPOSED AMENDED RULE 1118

The following is a summary of the proposed amendments to Rule 1118.

Subdivision (a) – Purpose

The purpose of PAR 1118 is to monitor and record operation data on refineries and related flaring operations, and to control and minimize flaring and flare-related emissions. The intention of this rule is not to be preemptive with respect to the operations and practices of any refinery, sulfur recovery plant, or hydrogen production plant that are essential and unavoidable for safety concerns.

Subdivision (b) – Applicability

All flares that are being operated at refineries, sulfur recovery plants, and hydrogen production plants are subject to PAR 1118.

Subdivision (c) – Definitions

New and Amended Definitions

Staff is proposing to add or amend the following definitions to the rule language:

Paragraph (c)(1) – Alternative Feedstock

Alternative feedstock is any feedstock, intermediate, product, or byproduct material containing organic material that is not derived from crude oil product, coal, natural gas, or any other fossil-fuel based organic material. Staff added this definition to ensure Rule 1118 remains applicable to refineries that transition some or all their crude oil feedstock to alternatives.

Paragraph (c)(4) – Essential Operational Need

Staff amended this definition to align the language with the new proposed requirement for clean service flares located at refineries (i.e., LPG flares) and to exclude any venting of clean service streams to be categorized as an "essential operational need" when measures, including any refrigeration/chiller system, modification or replacement of flare, or other applicable means under normal operation, have been implemented to reduce annual throughput at non-hydrogen clean service flares. However, specific situations such as LPG tank cleaning, maintenance, and inspections, will require the LPG tanks to be de-inventoried. Venting of the gas stream to the LPG flare during these situations may be inevitable and considered essential. Recovering LPG gas stream is not possible during such operations partially due to use of nitrogen as a purge gas in the stream and inability to store the gas due to tank outage.

Paragraph (c)(5) – Facility

This is a new definition to include any refinery, sulfur recovery plant, or hydrogen production plant to streamline rule language.

Paragraph (c)(6) – Flare

Current definition accounts for two types of flares: general service flares and clean service flares. Staff updated the definition of flare to separate the clean service flares that solely combust hydrogen vent streams from other types of clean service flares, because PAR 1118 considers different requirements for the clean service flares at refineries and Hydrogen production plants.

Hydrogen clean service flares are designed and configured by installation to combust only Clean Service Streams from a Hydrogen Production Plant; or

Non-hydrogen clean service flares are designed and configured by installation to combust only Clean Service Streams from a Facility other than Hydrogen Production Plant. LPG flares located inside the refineries are classified as non-hydrogen clean service flares.

Paragraph (c)(7) – Flare Event

Current definition of "flare event" contains statements that are not applicable to both planned and unplanned types of flare event. Staff moved the language pertained to determination of start and end of a flare event to Subdivision (d) – Requirements. Staff also moved the requirements for reporting flare events to Subdivision (l) – Flare Event Notifications Requirements.

Paragraph (c)(8) – Flare Event Notification System (FENS)

Staff updated this definition to remove the term "web-based" from the defined term. The definition was relocated with respect to the alphabetical order.

Paragraph (c)(11) – Flare Monitoring and Recording Plan (FMRP)

Staff added the definition for FMRP that is a compliance plan prepared by a facility and submitted to the Executive Officer for approval.

Paragraph (c)(13) – Flare Tip Velocity

Staff added the reference to Title 40 of the Code of Federal Regulations Part 63 Subpart CC – National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries for calculation of flare tip velocity, as part of incorporation of U.S. EPA RSR into PAR 1118.

Paragraph (c)(14) – Hydrogen Production Capacity

Staff added the definition for production capacity of a hydrogen production plant as its maximum rated capacity to produce hydrogen in million standard cubic feet of hydrogen per year calculated based on the maximum daily rated capacity. PAR 1118 Attachment C provides the list of hydrogen production plants and the hydrogen production capacity of those plants as listed in their current Title V permit or latest FMRP.

Paragraph (c)(17) – Oxides of Nitrogen (NOx) Emissions

NOx emissions are the sum of nitric oxide and nitrogen dioxide emitted, calculated, and expressed as nitrogen dioxide.

Paragraph (c)(18) – Performance Target

Performance target is an annual threshold on the amount of sulfur dioxide emissions or NOx emissions that can be emitted from a facility over one calendar year, otherwise the owner or operator is required to take certain actions, including preparing FMPs and paying mitigation fees.

Paragraph (c)(20) – Planned Flare Event

Staff updated the definition by adding the term "scheduled". The provision to determine "when to consider a startup process as a *planned* event after the end of an *unplanned* event" was moved to Subdivision (d) – Requirements.

Paragraph (c)(21) – Processing Capacity

Staff added the definition to streamline the rule the amount of crude oil and/or alternative feedstocks, which includes organic material that is not derived from crude oil product, coal, Natural Gas, or any other fossil-fuel based organic material, that a facility can process annually. PAR 1118 Attachment C provides the list of refineries and sulfur recovery plants, and the processing capacity of those facilities as listed in their current Title V permit, latest FMRP, or the California Energy Commission's list of California Oil Refinery Locations and Capacities[5]. If processing capacity is not available for a facility through any of the listed sources, the amended rule requires the owner or operator of the facility to report the processing capacity in million barrels for the prior calendar year within 30 days of the end of every calendar year.

Paragraph (c)(24) – Refine

Refine means to convert crude oil or Alternative Feedstock to produce more usable products such as gasoline, diesel fuel, aviation fuel, lubricating oils, asphalt or petrochemical feedstocks, or any other similar product.

Paragraph (c)(25) – Refinery

Staff updated the definition of "petroleum refinery" to remove the term "petroleum" from the definition and include a facility that is permitted to refine alternative feedstocks. The new definition of refinery now includes any facility that is permitted to refine crude oil or alternative feedstocks, and all portions of the refining operation, including those at non-contiguous locations operating flares, are considered as one refinery. The definition was relocated with respect to the alphabetical order.

Paragraph (c)(26) – Relative Cause

Staff added a new definition for the identified category of the cause of any flare event where more than 5,000 cubic feet of vent gas is combusted at the flare. The amended rule does not require specific cause analysis report to be prepared for such flare events, however the relative cause is required to be reported in the quarterly reports being submitted to South Coast AQMD and it may include emergency, shutdown, startup, turnaround, essential operational need, or unknown if undeterminable.

Paragraph (c)(33) – Unplanned Flare Event

Staff proposed a new definition for unplanned flare event as any flaring of vent gas during operations, such as unplanned shutdown, subsequent startup, valid breakdown, unforeseen maintenance, customer order kick back, or because of any situation beyond the operator's control including external power curtailment, natural disasters, acts of war or terrorism.

Removed Definition in Subdivision (c)

Staff removed the following definition from the rule language as it was referenced only in one place in the rule; thus, staff added the explanation where the term was used:

> *NOTICE OF SULFUR DIOXIDE EXCEEDANCE* is a notice issued by the Executive Officer to the owner or operator when the petroleum refinery has exceeded a performance target of this rule.

5 https://www.energy.ca.gov/data-reports/energy-almanac/californias-petroleum-market/californias-oil-refineries

Subdivision (d) – Requirements

Subparagraph (d)(1)(C)

Staff added the references to incorporate U.S. EPA RSR provisions into PAR 1118. The first reference is to Title 40 of the Code of Federal Regulations Part 63 Subpart CC – National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries for calculation of net heating value of vent gas. The second reference is to a new monitoring, recordkeeping, and reporting requirement in subdivision (j) that incorporates U.S. EPA RSR provisions for flare vent gas composition monitoring to obtain supportive data that may be used to calculate net heating value of vent gas.

Subparagraphs (d)(1)(E) and (d)(1)(F)

Staff streamlined the rule language to list all operational requirements in paragraph (d)(1) and moved the provisions to minimize combustion of vent gas and hydrogen sulfide in flares previously located at the end of this subdivision to be under paragraph (d)(1).

Paragraph (d)(2)

This provision was moved to this subdivision from the definition of Flare Event.

Paragraph (d)(3)

This provision was moved to this subdivision from Subdivision (i) – Flare Monitoring and Recording Plan Requirements.

Paragraph (d)(7)

The provisions of this paragraph are aligned with the requirements of U.S. EPA's 2015 federal Refinery Sector Rule. During any flare event that exceeds both or either of visible emission and flare tip velocity limits determined in South Coast AQMD Rule 401, subparagraph (d)(1)(B), or subparagraph (d)(1)(C), the owner or operator may not operate the flare above its smokeless capacity level, if the flare event is:

- The result of operator's fault or poor maintenance
- The second flare event from a single flare in any 3-calendar-year period for the same root cause as the first one for the same equipment
- The third flare event from a single flare in any 3-calendar-year period for any reason (any source)

Any flare events due to a cause beyond the operator's control, including external power curtailment (excluding interruptible service agreements), natural disasters or acts of war or terrorism should not be included in the event count.

Paragraph (d)(10)

The owners or operators of facilities are required to determine the relative cause of any flare event with the vent gas stream of more than 5,000 standard cubic feet to be reported in their quarterly reports, using the flare cause codes as previously listed in Table 2-1 of this staff report.

Removed Provisions in Subdivision (d)

Staff consolidated all provisions and requirements related to submission of specific cause analysis and corrective actions implementation schedule to a new subdivision (i.e., Subdivision (e) – Specific Cause Analysis Requirements).

Staff moved the monitoring and recordkeeping provisions listed under Requirements to Subdivision (j).

Staff also removed outdated provisions that previously required the facility to prepare and submit scoping document as part of the amendment to Rule 1118 in 2017.

Subdivision (e) – Specific Cause Analysis Requirements

This subdivision includes the provisions and schedules related to specific cause analysis. Staff moved the language down from "Subdivision (d) – Requirements" to this new subdivision.

Paragraphs (e)(1) and (e)(2)

Rule 1118 requires specific cause analysis to be conducted for:

- every flare event that exceeds the specified emissions threshold(s) (paragraph (d)(5));
- every single flare with a flare event during the same period of time when the smokeless capacity of the flare is exceeded and either the applicable visible emission limit or the applicable flare tip velocity limit is exceeded.

Staff added new provisions in paragraphs (e)(1) and (e)(2) to incorporate U.S. EPA RSR provisions into PAR 1118. The new language identifies the situations where a single specific cause analysis is deemed sufficient for flare events that involve exceedance of multiple operational limits at more than one flare.

Paragraph (e)(5)

Staff added the requirement for the owner or operator of a facility that submitted a specific cause analysis report to provide the record of corrective action(s) completed, aligned with the similar requirement established by U.S. EPA RSR.

Subdivision (f) – Performance Targets Requirements

Paragraph (f)(1)

Staff updated SO_2 performance target to gradually decrease over time. PAR 1118 requires facilities to meet a performance target of 0.35 ton of sulfur dioxide per million barrels of processing capacity for reporting emissions for calendar year 2026, and a performance target of 0.25 ton of sulfur dioxide per million barrels of processing capacity for reporting emissions for calendar year 2028 and thereafter.

Staff proposed to change the reference for facilities processing capacity from "calendar year 2004" to "as listed in their current Title V permit, latest FMRP, the California Energy Commission's list of California Oil Refinery Locations and Capacities for each calendar year, or as reported by the facility", as outlined in PAR 1118 Attachment C. PAR 1118 Attachment C Table C1 lists processing capacities for refineries.

Paragraph (f)(2)

Staff proposed a new performance target of 0.3 pound of NOx per million standard cubic feet of hydrogen production capacity to control emissions from hydrogen clean service flares. These flares are solely used for vent gas streams from hydrogen production plants. PAR 1118 Attachment C Table C2 lists production capacities for Hydrogen production plants.

This provision becomes effective when owner or operators of hydrogen production plants report emissions for calendar year 2025 and thereafter.

Paragraph (f)(3)

This paragraph was updated to also include hydrogen production plants that are subject to meet the NOx performance target in paragraph (f)(2).

Paragraph (f)(4)

Staff updated this paragraph to clarify the schedule for the owner or operator of a facility that exceeds the applicable SO_2 or NOx performance target for any calendar year to submit a flare minimization plan and appropriate mitigation fees. Staff also added new provisions to address the owner or operator of a facility with any periods of invalid monitoring data within the calendar year who seeks to use an alternative method to substitute ethe missing data. The owner or operator is required to calculate the annual flare emissions using either the approved alternative data substitution that was submitted for the Executive Officer approval within 90 days following the end of the calendar year when performance target exceedance occurred, or the standard data substitution procedures in PAR 1118 Attachment B if the data substitution is not approved by the Executive Officer within 12 months of submittal. If the applicable data used to calculate the annual flare emissions confirms that the facility exceeded the applicable performance target, the owner or operator is required to submit a flare minimization plan and appropriate mitigation fees within 14 months of submitting supporting data for approval.

Staff updated mitigation fees using Consumer Price Index (CPI) for 2022 to serve as the baseline. Staff also transferred requirements on mitigation fees to a new attachment (PAR 1118 Attachment D). This attachment provides the calculations of facility-specific performance targets, the new baseline fees, and methodology to adjust the fees annually using CPI.

Subdivision (g) – Non-Hydrogen Clean Service Flares Requirements

This is a new subdivision to establish new requirements for owner or operator of non-hydrogen clean service flares (i.e., LPG flares).

Paragraph (g)(1)

The owner or operator of an LPG flare is required to submit a permit application for any LPG flare that has exceeded the proposed annual throughput level with total heat content (based on higher heating value) of 15,000 MMBtu per year in any two consecutive years since 2017.

This provision is applicable to any LPG flare that exceeded the proposed threshold preceding the date of PAR 1118 adoption and includes requirements and schedule to install necessary equipment to reduce flaring emissions at such flares.

Paragraph (g)(2)

Staff added the requirement to maintain LPG clean service flares to meet an annual throughput level with total heat content (based on higher heating value) of 15,000 MMBtu per year for two consecutive calendar years. Consideration to allow for exceedance to occur at most every other year was established to accommodate planned tank inspection, maintenance, and cleaning which is essential for safety and operational concerns.

This provision is effective when owner or operators of LPG flares report emissions from these flare for calendar year 2026 or 12 months after the permit is issued, whichever is later, and continuously thereafter. The schedule considers the permitting timeframe and provides time for equipment installation or implementation.

Subdivision (h) – Flare Minimization Plan Requirements and Schedule

Paragraph (h)(1)

Staff did not add any new consideration for FMPs to be submitted upon performance target exceedance, except for updating the language to be applicable to both SO_2 and NOx performance targets as established in paragraph (f).

Paragraph (h)(2)

Staff added a new requirement for owner or operator of a facility to submit an FMP for any calendar year when annual throughput threshold was exceeded at a non-hydrogen clean service (LPG) flare.

Subdivision (i) – Flare Monitoring and Recording Plan Requirements

Staff streamlined the language in this subdivision but did not propose any new requirement or consideration. Provisions related to commencement of operation at a new or an existing non-operating facility that plans to recommence operation were moved to Subdivision (d) – Requirements (paragraph (d)(3)).

Subdivision (j) – Monitoring, Recordkeeping, and Reporting Requirements

Paragraph (j)(1)

Staff moved the provisions from Subdivision (d) – Requirements that are related to MRR to this subdivision to streamline the rule language.

Paragraph (j)(3) and Table 2

Staff proposed to remove the allowance to use an on/off flow indicator for the purpose of monitoring and recording the vent gas flow at general service flares and all clean service flares (hydrogen and non-hydrogen), in PAR 1118 Table 2. This change is effective pursuant to the compliance schedule as stated in PAR 1118 paragraph (j)(10).

Paragraph (j)(5)

Staff added a new provision to incorporate U.S. EPA RSR requirements for flare vent gas composition monitoring that may be used to calculate net heating value of vent gas.

Subparagraph (j)(7)(B)

This subparagraph was the language previously included under paragraph (j)(6) and is now separated and updated to be applicable to all flares rather than just general service flares. Staff updated the provision to be consistent with the new consideration to require the use of continuous vent gas flow meter for clean service flares in addition to general service flares (PAR 1118 Table 2).

Paragraph (j)(8)

Staff removed the reference to "any other equivalent device" in lieu of the requirement to install and maintain a thermocouple to detect the presence of a pilot flame as all flares are required to have a thermocouple present to detect the pilot flame.

Paragraph (j)(9)

Staff removed the outdated language from this provision.

Paragraph (j)(10)

Staff updated this provision to be applicable to general service flares, and hydrogen clean service flares. Owner or operator of a general service flare is required to have a vent gas flow meter installed at the time of rule adoption. Owner or operator of a hydrogen clean service flare is granted six months after the date of rule adoption to install and operate a continuous vent gas flow meter and meet the criteria of this provision.

This provision also requires monitoring and recording of pilot and purge gas flows separately using a flow meter or an equivalent approved device.

Paragraph (j)(13)

This provision is not a new language and was moved down from the beginning of this very subdivision.

Paragraph (j)(14) – Annual Emissions and Throughput Reporting

Staff added this new requirement for reporting annual SO_2 or NOx emissions, or annual LPG flare throughput by the owner or operator of a facility when they meet the criteria that requires them to submit an FMP and corresponding mitigation fees pursuant to paragraph (f)(3) or paragraph (g)(2). This information is required to be submitted to South Coast AQMD through FENS no later than 30 days after the end of the calendar year for which they are required to submit the FMP and mitigation fees. Staff will work on implementing changes to FENS after rule adoption to address this requirement. Until those changes have been finalized, facilities will be required to report flares' annual emissions and throughput (if applicable) through email (Rule1118@aqmd.gov).

Paragraph (j)(15) – Quarterly Reports

This provision is old language and was moved up from Subdivision (l) – Flare Event Notification Requirements.

Facilities have been submitting quarterly reports to South Coast AQMD for more than a decade. Quarterly reports include comprehensive flare event data which is only available to public through submitting a Public Records Request to South Coast AQMD. Quarterly reports are now required to be submitted through FENS to accommodate the request by community members for access to these data on a timely manner. Staff intends to standardize the format for the facilities to submit the quarterly reports to streamline the process of making the data publicly available. Staff will work on the changes to FENS after rule adoption through a public process that involves both the regulated facilities and the community. Until those changes have been finalized, facilities will be required to submit the quarterly reports through email (Rule1118@aqmd.gov).

Paragraph (j)(16) – Monthly Emissions Reports

Staff proposed a new reporting requirement for the owner or operator of facilities to submit preliminary emissions and operational data every month, in addition to the comprehensive quarterly reports. Monthly reports are required to be submitted through FENS. This proposed requirement is expected to accommodate early public access to preliminary data available sooner than quarterly data reports are prepared and submitted. Staff proposed the allowance for the owners and operators to not being required to submit complete information and details (e.g., cause) in the monthly reports while flag data as "preliminary" with the ability to go back and update data at a later time. Staff will work on implementing changes to FENS after rule adoption to address this requirement. Until those changes have been finalized, facilities will be required to submit the monthly reports through email (Rule1118@aqmd.gov).

Paragraph (j)(17) – Specific Cause Analysis Reports

Staff added a new reporting requirement for specific cause analyses and complete details to be submitted through FENS. Staff will work on implementing changes to FENS after rule adoption to address this requirement. Until those changes have been finalized, facilities will be required to submit SCARs through email (Rule1118@aqmd.gov).

Paragraphs (j)(18) and (j)(19)

Staff added the requirements for electronic submission of annual emissions reporting, annual throughout reporting, quarterly reports, monthly reports, and specific cause analysis report to an electronic address (Rule1118@aqmd.gov) during the FENS downtime or when specific feature(s) is not available on FENS. This provision accommodates the reporting requirements for which the appropriate feature(s) may not be yet available in FENS at the time of rule adoption. Staff will work on implementing changes to FENS after rule adoption to incorporate those features.

Paragraph (j)(20)

Staff added a new requirement for the owner or operator of facilities to report processing capacity if no processing capacity value is listed for the facility in Table C1 of PAR 1118 Attachment C.

Subdivision (k) – Testing and Monitoring Methods

Staff moved up this subdivision to follow Subdivision (j) – Monitoring, Recordkeeping and Reporting Requirements.

Subparagraph (k)(1)(C)

Staff updated the required frequency to verify the accuracy of vent gas flow meters to every calendar year with at least 6 months' time-lag from the last verification procedure.

Paragraph (k)(3)

Staff added the reference to Rule 218.2 and Rule 218.3 to this paragraph, because a CEMS that is subject to Rule 2012 must be certified pursuant to the implementation schedule in paragraph (d)(3) of Rules 218.2 and 218.3.

Subdivision (l) – Flare Event Notification Requirements

Provisions related to quarterly reports were moved to Subdivision (j) – Monitoring, Recordkeeping, and Reporting Requirements (paragraph (j)(13)).

Paragraph (l)(2)

Staff is proposing to require notification of start of a flare event to be reported through FENS within one hour of the start for all flare events (planned and unplanned) that exceed at least one of the following thresholds: 100 pounds of VOC emissions; 500 pounds of sulfur dioxide emissions; or 500,000 standard cubic feet of flared vent gas. Previously, the owner or operator was required to create a notification for a "planned" flare event at least 24 hours before the planned flare event and send a second notification one hour in advance of start time of the flare event. This proposed change was to align the requirements for planned and unplanned events with respect to reporting the start of a flare event.

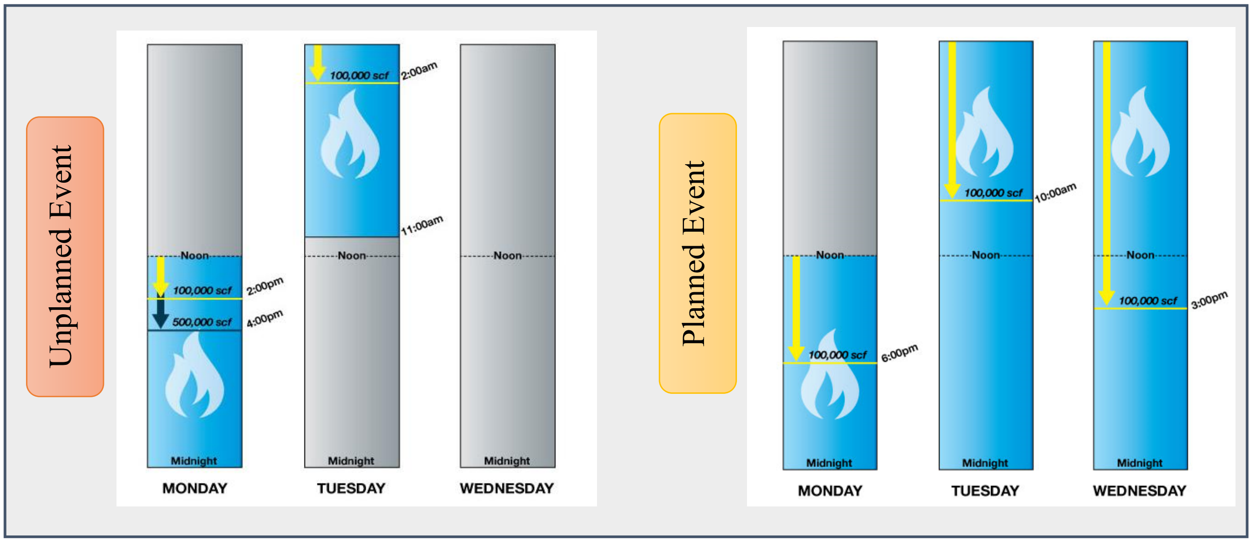


Figure 4-2. Demonstration of Notification Triggers for Unplanned vs. Planned Flare Event

Staff also updated the provision to require the owner or operator of the facilities to provide information about the ending time of flare event and exceedance of flare smokeless capacity during the flare event through FENS within 24 hours of ending the flare event.

Paragraph (l)(3) – Planned Flare Event Notifications

Staff removed the notification requirement within one hour prior to start of a planned flare event to be consistent with the proposed change in paragraph (l)(2). Additional notification is still required for every planned flare event at least 24 hours prior to the start time.

Paragraph (l)(4) – Unplanned Flare Event Notifications

Staff added clarification regarding notification requirements for unplanned flare events that last longer than 24 hours. The operator is required to end such unplanned flare event at the end of the starting calendar day and generate an unplanned flare event notification for every calendar year that flaring continues to occur.

Paragraph (l)(6) – Characterizing and Reporting Flare Events

Staff combined all provisions that are related to characterization of flare events for the purpose of reporting through FENS to this paragraph. These provisions were previously included in the definitions of "Flare Event" and "Planned Flare Event".

Removed Provisions

Staff moved the quarterly reports requirements listed under Flare Event Notification Requirements to Subdivision (j).

Subdivision (m) – Exemptions

Staff updated the references in this subdivision, but there was no change to the language.

Attachment A – Flare Monitoring System Requirements

Staff updated the reference to South Coast AQMD Rule 218.1 to Rule 218.2 and Rule 218.3, as applicable. No other changes were made to flare monitoring system requirements.

Also, staff proposed to allow the owner or operator of facilities to postpone the required calibration of monitoring systems for up to 72 hours during an ongoing flare event. According to Rule 1118, the owner or operator of a facility is required to calibrate the flare and sulfur monitoring systems daily and flare emissions cannot be measurement during calibration procedures which can lead to punitive data substitution procedures. Staff does not think the punitive data substitution procedures should apply for required calibration procedures so is proposing to allow for delayed calibrations during an ongoing flare event.

Attachment B – Guidelines for Calculating Flare Emissions

Section (1) – Emission Calculation Procedures

Staff remove the outdated procedures to calculate air pollutants emissions in the vent gas.

Section (3) – Data Substitution Procedures

Staff updated the some of the terms in the equations for calculation of estimated flow rate, estimated higher heating value, and estimated total sulfur concentration.

Missing data substitution procedures are required pursuant to PAR 1118 Attachment B, and the owner or operator is required to use the maximum flow rate measured and recorded for a flare during the previous 20 quarters preceding the flare event for the purpose of data substitution. Staff added provisions to allow for data substitution (i.e., flow rate, high heating value, and sulfur concentration) using recorded data during one hour before and one hour after the period that data is not recorded, if it lasts for 15 minutes or less.

Attachment C

Staff added a new attachment to list the updated processing capacity for refineries and production capacity for hydrogen production plants. Staff proposed to update the facilities processing capacity used to calculate facility specific SO_2 performance target that was previously referenced to the processing capacity values from 2004. Any facility without publicly available processing capacity information is required to report this value to the Executive Officer pursuant to paragraph (j)(18). The processing capacity is required to be updated after the date of rule adoption if the value changes in the facility's Title V permit, the facility's FMRP, or the California Energy Commission's list of California Oil Refinery Locations and Capacities, or the owner or operator of the facility reports an updated value pursuant to paragraph (j)(18).

Attachment D

Staff added a new attachment to provides guidelines for calculating facility specific SO_2 performance target for a refinery, NOx performance targets for hydrogen production plants, and mitigation fees adjusted based on consumer price index.

Section (3) – Calculations for Baseline Mitigation Fees

Mitigation fees were last updated in 2004. Staff is proposing to adjust the mitigation fees, using the 2022 Consumer Price Index (CPI), according to the schedule in the table below. Staff also proposed to use these updated mitigation fees as baseline mitigation fees.

Table 4-1. Mitigation Fees for Exceeding SO_2 Performance Target

Excess Emissions (%)	Mitigation Fees ($/ton of Excess SO_2)
≤10	25,000
>10 to ≤20	50,000
>20	100,000

Section (4) – Calculations for Adjusted Mitigation Fees

Staff proposed to adjust the mitigation fees annually based on the listed CPI for each year by the State of California Department of Industrial Relations (https://www.dir.ca.gov/OPRL/). The owner or operator of facilities that are required to pat the mitigation fees pursuant to paragraph (f)(3) or (g)(2) must pay the fees as calculated using CPI for the calendar year that the performance target was exceeded, or the most recently available CPI using the equation in PAR 1118 Attachment D.

CHAPTER 5 : IMPACT ASSESSMENT

INTRODUCTION

EMISSIONS INVENTORY AND EMISSION REDUCTIONS

COST-EFFECTIVENESS AND INCREMENTAL COST-EFFECTIVENESS

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INTRODUCTION

Rule 1118 was originally adopted by South Coast AQMD Governing Board on February 13, 1998, to control and reduce emissions from refinery flares. PAR 1118 is expected to impact 31 flares located at 12 facilities with updated requirements for the SO_2 performance target. Four out of 12 facilities (i.e., four flares) are expected to be impacted by the new NOx performance target requirements for clean service flares at hydrogen production plants. Three out of 12 facilities (i.e., three flares) are expected to be impacted by the new throughput threshold requirements for clean service flares at refineries (LPG flares). The requirement for installation of a continuous vent gas flow meter impacts four hydrogen clean service flares and is expected to be in operation consistent with a specified schedule.

EMISSIONS INVENTORY

Flares regulated by Rule 1118 are sources of different pollutant emissions, including SO_2, NOx, VOC, and PM10. The table below shows the level of emitted emissions from all flares since 2012 reported by the facilities.

Table 5-1. Rule 1118 Emissions Estimates from All Facilities (2012–2022)

Year	SO_2 Emissions (ton/year)	NOx Emissions (ton/year)	VOC Emissions (ton/year)	PM_{10} Emissions (ton/year)
2012	122.83	45.15	29.36	9.75
2013	81.62	34.35	19.93	8.00
2014	103.13	22.29	9.12	4.84
2015	180.93	41.56	13.94	7.37
2016	67.29	26.36	13.67	7.79
2017	66.05	19.58	7.09	4.30
2018	63.43	17.54	5.38	2.00
2019	59.02	19.41	22.12	3.07
2020	62.27	18.54	58.39	4.09
2021	116.65	22.35	44.58	4.05
2022	63.14	30.70	99.64	8.27
Average	**73.48**	**21.35**	**56.18***	**4.30**

* Average excludes reported emissions from 2018 and before because of different VOC emission factors.

As part of 2017 amendment to Rule 1118, staff increased the VOC emission factor based on EPA's updated AP-42 guidance by 10-fold (from 0.063 to 0.66 pound of VOC per million Btu). Therefore, reported VOC emissions after 2018 are different in order of magnitude from the level of VOC emissions reported in the prior years.

EMISSION REDUCTIONS

PAR 1118 is expected to achieve emission reductions in all types of emissions (SO_2, VOC, and NOx) and to be aligned with AB 617 CERP actions through establishing the new SO_2 performance target of 0.25 ton per million barrels of processing capacity. The table below shows the expected reduction in different types of emissions from flares based on the level of emissions in 2017 which was established as the baseline year in AB 617 CERP for the Wilmington, Carson, West Long Beach community. The listed values for emission reductions are the average expected reductions for each type of pollutant compared to the emission level in 2017 (AB 617 CERP baseline year) based on the proposed annual SO_2 performance target of 0.25 ton per million barrels of processing capacity.

Table 5-2. Estimated Emission Reductions[a] at Proposed Annual SO_2 Performance Target of 0.25 ton/MMbbl

Pollutant Type	All Facilities		Wilmington, Carson, West Long Beach Facilities		
	Ton per Year	Percent	Ton per Year	Percent	CERP Emission Reductions Target (tpy) by 2030
SO_2	16.6	30	13.8	51[b]	11
VOC	3.3	16	3.3	20[c]	1
NOx	2.2	15	1.8	17[d]	19

[a] Emission reduction values are calculated based on emission level in 2017 (AB 617 CERP baseline year), except for VOC for which values are calculated based on emission levels in 2019 due to updated emission factor for VOC in effect since 2019.
[b] CERP's goal of achieving a minimum of 50 percent SO_2 emission reductions from refineries by 2030 is expected to be achieved through Rule 1118.
[c] CERP's goal of achieving a minimum of 50 percent VOCs emission reductions from refineries by 2030 is expected to be achieved through Rules 1178, 1118, and/or 1173.
[d] CERP's goal of achieving a minimum of 50 percent NOx emission reductions from refineries by 2030 is expected to be achieved primarily through Rule 1109.1 and partially through Rule 1118.

Reductions in SO_2 and VOCs emissions in the Wilmington, Carson, West Long Beach community are expected to exceed CERP emission reductions targets for flaring at refineries by 2030. NOx emission reductions from refinery flares in the Wilmington, Carson, West Long Beach community is estimated to be less than the corresponding CERP emission reductions target by 2030. However, CERP's goal of achieving a minimum of 50 percent NOx emission reductions by 2030 from refineries is expected to be achieved primarily through Rule 1109.1 and partially through Rule 1118. NOx emission reductions from refinery equipment at the Wilmington, Carson, West Long Beach community subject to Rule 1109.1 is estimated to be 1,095-1,460 tons per year by 2030 in CERP. Current Rule 1109.1 is expected to achieve 1,643 tons per year of NOx emission reductions from refineries located at the Wilmington, Carson, West Long Beach community which exceeds the expected NOx emission reductions as established by CERP for this community and compensates for the shortfall in expected NOx emission reductions from Rule 1118.

COST-EFFECTIVENESS

Health and Safety Code Section 40920.6 requires a cost-effectiveness analysis when establishing BARCT requirements. South Coast AQMD routinely conducts cost-effectiveness analyses regarding proposed rules and regulations that result in the reduction of criteria pollutants (NOx, SOx, VOC, PM, and CO). PAR 1118 does not establish BARCT requirements; however, staff conducted a cost-effectiveness analysis of the proposed annual throughput threshold to control NOx emissions from LPG flares, as presented in the table below.

The cost-effectiveness of a control technology is measured in terms of the control cost in dollars per ton of air pollutant reduced for each class and category of equipment. The costs for the control technology include purchasing, installation, operating, and maintaining the control technology. South Coast AQMD typically relies on the Discounted Cash Flow (DCF) method which converts all costs, including initial capital investments and costs expected to be incurred in the present and all future years of equipment life, to a present value. The final cost-effectiveness measure is derived by dividing the present value of total costs by the total emissions reduced over the equipment life of 25 years.

Staff evaluated the minimum annual throughput at which LPG recovery was cost-effective to be equal to 15,000 MMBtu per year. Cost-effectiveness was calculated to be $55,000 per ton of NOx reduced over the lifetime of the auxiliary gas refrigeration/compressor system which is well below the cost-effectiveness threshold of $349,000 (adjusted for CPI) per ton of NOx reduced as established by 2022 AQMP. The annual throughput of 15,000 MMBtu per year or greater is below the cost-effectiveness threshold of $349,000 (adjusted for CPI) per ton of NOx reduced.

INCREMENTAL COST-EFFECTIVENESS

Health and Safety Code Section 40920.6 requires an incremental cost-effectiveness analysis for BARCT rules or emission reduction strategies when there is more than one control option which would achieve the emission reduction objective of the proposed amendments relative to ozone, carbon monoxide, sulfur oxides, oxides of nitrogen, and their precursors. Incremental cost-effectiveness is the difference in the dollar costs divided by the difference in the emission reduction potentials between each progressively more stringent potential control option as compared to the next less expensive control option.

Staff evaluated the cost-effectiveness of reducing the throughput threshold beyond the proposed threshold of 15,000 MMBtu per year to a lower threshold of 3,500 MMBtu per year. The lower threshold would require all three refineries that operate a non-hydrogen clean service flare (LPG flare) to install a larger refrigeration/chiller system regardless of whether a new flare was installed. Staff estimates that the new larger refrigeration/chiller system will need to be twice as large with an estimated cost of approximately $21 MM. The larger system will also require approximately double the electricity usage since a larger compressor will be necessary. This increase in operating cost will negate any potential profit from recovery of the LPG when compared to the cost savings associated with the proposed 15,000 MMBtu per year threshold. Furthermore, since one facility currently recovers nearly all of the LPG, the incremental emission reductions from that the facility is low. The annual throughput of 3,500 MMBtu/year has an incremental cost-effectiveness of $16 MM and low incremental emission reductions of 0.006 tons per year for all three facilities. The table below summarizes both the cost-effectiveness and incremental cost-effectiveness assessment.

Table 5-3. Cost-Effectiveness and Incremental Cost-Effectiveness Analysis for LPG Flares

Equipment Type	Cost-Effectiveness at 15,000 MMBtu/yr	Incremental Cost-Effectiveness at 3,500 MMBtu/yr
LPG Flare	\$58,000 per ton of NOx reduced	\$16 MM per ton of NOx reduced

ANTICIPATED SCHEDULE FOR EMISSION REDUCTIONS

The SO_2 performance target of 0.5 ton per million barrels of processing capacity remains effective upon rule adoption and the owners or operators of facilities are required to meet this target when reporting their SO_2 emissions for calendar year 2024. The SO_2 performance target of 0.35 ton per million barrels of processing capacity becomes effective for reporting SO_2 emissions for calendar year 2025 and is expected to achieve 9.3 tons of SO_2 emission reductions per year in average with respect to baseline year emissions (i.e., 2017). The SO_2 performance target of 0.25 ton per million barrels of processing capacity becomes effective for reporting SO_2 emissions for calendar year 2026 and after and is expected to achieve an extra 7.3 tons of SO_2 emission reductions per year in average, i.e., an average of 16.6 tons of SO_2 per year in total. The table below shows the schedule for expected emission reductions under PAR 1118 in all types of emissions associated with flaring. The presented emission reductions are the average expected emission reductions for each type of pollutant compared to the emission level in 2017 (AB 617 CERP baseline year) based on the corresponding proposed annual SO_2 performance target.

Table 5-4. PAR 1118 Estimated Emission Reductions and Schedule*

Pollutant Type	Calendar Year 2026		Calendar Year 2028 and after	
	Ton per Year	Percent	Ton per Year	Percent
SO_2	9.3	17	16.6	30
VOC	1.9	9	3.3	16
NOx	1.2	8	2.2	15

* Emission reductions are calculated from emissions occurring during the baseline year 2017 as established in the AB 617 CERP for the Wilmington, Carson, West Long Beach community.

SOCIOECONOMIC IMPACT ASSESSMENT

A socioeconomic impact assessment will be conducted and released for public review and comment at least 30 days prior to the South Coast AQMD Governing Board Hearing for PAR 1118, which is anticipated to be heard on April 5, 2024 (subject to change).

CALIFORNIA ENVIRONMENTAL QUALITY ACT ANALYSIS

Pursuant to the California Environmental Quality Act (CEQA) and South Coast AQMD's certified regulatory program (Public Resources Code Section 21080.5, CEQA Guidelines Section 15251(l) and South Coast AQMD Rule 110), the South Coast AQMD, as lead agency, is reviewing the proposed project (PAR 1118) to determine if any potential adverse environmental impacts will occur. Appropriate CEQA documentation will be prepared based on the analysis.

Draft Findings Under Health and Safety Code Section 40727

Health and Safety Code Section 40727 requires that prior to adopting, amending, or repealing a rule or regulation, the South Coast AQMD Governing Board shall make findings of necessity, authority, clarity, consistency, non-duplication, and reference based on relevant information presented at the public hearing, and in the staff report.

Necessity

Proposed Amended Rule 1118 is needed to reduce emissions from flares operated at petroleum refineries and related operations to satisfy the commitment in the resolution from the 2017 amendment of Rule 1118 and to achieve the goals that were set forth by the AB 617 CERP for the Wilmington, Carson, West Long Beach community.

Authority

The South Coast AQMD Governing Board has authority to adopt amendments to Rule 1118 pursuant to Health and Safety Code Sections 39002, 40000, 40001, 40440, 40702, 40725 through 40728, and 41508.

Clarity

Proposed Amended Rule 1118 is written or displayed so that its meaning can be easily understood by the persons directly affected by it.

Consistency

Proposed Amended Rule 1118 is in harmony with the U.S. EPA's Refinery Sector Rule, and not in conflict with or contradictory to, existing statutes, court decisions, or state or federal regulations.

Non-Duplication

Proposed Amended Rule 1118 will not impose the same requirements as any existing state or federal regulations. The proposed amended rule is necessary and proper to execute the powers and duties granted to, and imposed upon, the South Coast AQMD.

Reference

In drafting Proposed Amended Rule 1118, the following statutes which South Coast AQMD hereby implements, interprets, or makes specific are referenced: Assembly Bill 617, Health and Safety Code Sections 39002, 40000, 40001, 40702, 40440(a), 40440(b), 40440(c), 40725 through 40728.5, and 41508.

Comparative Analysis

Under Health and Safety Code Section 40727.2, South Coast AQMD is required to perform a comparative analysis when adopting, amending, or repealing a rule or regulation. The comparative analysis is relative to existing federal requirements, existing or proposed South Coast AQMD rules and air pollution control requirements and guidelines which are applicable to combustion equipment subject to PAR 1118. The comparative analysis for PAR 1118 will be included in the draft staff report released no later than 30 days prior to the scheduled public hearing.