(Adopted February 13, 1998)(Amended November 4, 2005)(Amended July 7, 2017)
(Amended January 6, 2023)

RULE 1118. CONTROL OF EMISSIONS FROM REFINERY FLARES

(a) Purpose and Applicability

The purpose of Rule 1118 is to monitor and record data on refinery and related flaring operations, and to control and minimize flaring and flare related emissions. The provisions of this rule are not intended to preempt any petroleum refinery, sulfur recovery plant and hydrogen production plant operations and practices with regard to safety. This rule applies to all flares used at petroleum refineries, sulfur recovery plants and hydrogen production plants.

(b) Definitions

For the purpose of this rule, the following definitions shall apply:

(1) CLEAN SERVICE STREAM is a gas stream such as natural gas, hydrogen gas and/or liquefied petroleum gas. Other gases with a fixed composition that inherently have a low sulfur content and are vented from specific equipment may be classified as clean service streams if determined to be equivalent and approved in writing by the Executive Officer.

(2) EMERGENCY is a condition beyond the reasonable control of the owner or operator of a flare requiring immediate corrective action to restore normal and safe operation, which is caused by a sudden, infrequent and not reasonably preventable equipment failure, upset condition, equipment malfunction or breakdown, electrical power failure, steam failure, cooling air or water failure, instrument air failure, reflux failure, heat exchanger tube failure, loss of heat, excess heat, fire and explosion, natural disaster, act of war or terrorism or external power curtailment, excluding power curtailment due to an interruptible power service agreement from a utility. For the purpose of this rule, a flare event caused by poor maintenance, or a condition caused by operator error that results in a flare event shall not be deemed an emergency.

(3) ESSENTIAL OPERATIONAL NEED is an activity other than resulting from poor maintenance or operator error, determined by the Executive Officer to meet one of the following:

(A) Temporary fuel gas system imbalance due to:

(i) Inability to accept gas compliant with Rule 431.1 by an electric generation unit at the facility that produces electricity to be used in a state grid system, or

(ii) Inability to accept gas compliant with Rule 431.1 by a third party that has a contractual gas purchase agreement with the facility, or

(iii) The sudden shutdown of a refinery fuel gas combustion device that is not due to an emergency or breakdown;

(B) Venting of streams that cannot be recovered due to incompatibility with recovery system equipment or with refinery fuel gas systems, including supplemental natural gas or other gas compliant with Rule 431.1 that is used for the purpose of maintaining the higher heating value of the vent gas above 300 British Thermal Units per standard cubic foot. Such streams include inert gases, oxygen, gases with low or high molecular weights outside the design operating range of the recovery system equipment and gases with low or high higher heating values that could render refinery fuel gas systems and/or combustion devices unsafe;

(C) Venting of clean service streams to a clean service flare or a general service flare.

(4) FLARE is a combustion device that uses an open flame to burn combustible gases with combustion air provided by uncontrolled ambient air around the flame. When used as a verb means the combustion of vent gases in a flare device. Based on their use, flares are classified as:

(A) CLEAN SERVICE FLARE is a flare that is designed and configured by installation to combust only clean service streams.

(B) GENERAL SERVICE FLARE is a flare that is not a Clean Service Flare.

(5) FLARE EVENT is any intentional or unintentional combustion of vent gas in a flare. The start is determined by the vent gas flow velocity exceeding 0.10 feet per second and the end is determined when the vent gas flow velocity drops below 0.12 feet per second, or when the owner or operator can demonstrate that no more vent gas was combusted based upon the monitoring records of the flare water seal level and/or other parameters as approved by the Executive Officer in the Flare Monitoring and Recording

Plan as described in subdivision (f). For flare events that can be attributed to the same process unit(s) or equipment and has more than one start and end within a 24 hour period, it shall be considered a continuation of the same event, and not a separate or unique event. For a flare event that continues for more than 24 hours, each calendar day of venting of gases shall constitute a flare event.

(6) FLARE GAS RECOVERY SYSTEM is a system comprised of compressors, pumps, heat exchangers, knock-out pots and water seals, installed to prevent or minimize the combustion of vent gas in a flare.

(7) FLARE MINIMIZATION PLAN is a document intended to meet the requirements of subdivision (e).

(8) FLARE MONITORING SYSTEM is the monitoring and recording equipment used for the determination of flare operating parameters, including higher heating value, total sulfur concentration, combustion efficiency, standard volumetric flow rate and/or on/off flow indication.

(9) FLARE TIP VELOCITY is the velocity of flare gases exiting a flare tip averaged over 15 minute time periods, starting at 12 midnight to 12:15 am, 12:15 am to 12:30 am, and so on, concluding at 11:45 pm to midnight, and calculated as the volumetric flow divided by the area of the flare tip.

(10) HYDROGEN PRODUCTION PLANT is a facility that produces hydrogen by steam hydrocarbon reforming, partial oxidation of hydrocarbons, or other processes, using refinery fuel gas, process gas or natural gas, and which supplies hydrogen for petroleum refinery operations.

(11) NATURAL GAS is a mixture of gaseous hydrocarbons, with at least 80 percent methane (by volume), and of pipeline quality, such as the gas sold or distributed by any utility company regulated by the California Public Utilities Commission.

(12) 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.

(13) PETROLEUM REFINERY is a facility that processes petroleum, as defined in the North American Industry Classification System (NAICS) as Industry No. 324110, Petroleum Refineries. For the purpose of this rule, all portions of the petroleum refining operation, including those at non-contiguous locations operating flares, shall be considered as one petroleum refinery.

(14) PILOT is an auxiliary burner used to ignite the vent gas routed to a flare.

(15) PLANNED FLARE EVENT is any flaring as a result from process unit(s) or equipment startup, shutdown, turnaround, maintenance, clean-up, and non-emergency flaring. Flaring from the startup of a process unit or equipment that is more than 36 hours after the end of an unplanned flare event of that same process unit shall be considered a Planned Flare Event.

(16) PURGE GAS is a continuous gas stream introduced into a flare header, flare stack and/or flare tip for the purpose of maintaining a positive flow that prevents the formation of an explosive mixture due to ambient air ingress.

(17) REPRESENTATIVE SAMPLE is a sample of vent gas collected from the location as approved in the Flare Monitoring and Recording Plan and analyzed utilizing test methods specified in subdivision (j).

(18) SHUTDOWN is the procedure by which the operation of a process unit or piece of equipment is stopped due to the end of a production run, or for the purpose of performing maintenance, repair and replacement of equipment. Stoppage caused by frequent breakdown due to poor maintenance or operator error shall not be deemed a shutdown.

(19) SMOKELESS CAPACITY is the maximum vent gas volumetric flow rate or mass flow rate that a flare is designed to operate without visible emissions.

(20) SPECIFIC CAUSE ANALYSIS is a process used by a facility subject to this rule to investigate the cause of a flare event, identify corrective measures and prevent recurrence of a similar event.

(21) STARTUP is the procedure by which a process unit or piece of equipment achieves normal operational status, as indicated by such parameters as temperature, pressure, feed rate and product quality.

(22) SULFUR RECOVERY PLANT is a facility that recovers elemental sulfur or sulfur compounds from sour gases and/or sour water generated by petroleum refineries.

(23) TURNAROUND is a planned activity involving shutdown and startup of one or several process units for the purpose of performing periodic maintenance, repair and replacement of equipment or installation of new equipment.

(24) VENT GAS is any gas generated at a facility subject to this rule that is routed to a flare, excluding assisting air or steam, which are injected in the flare combustion zone or flare stack via separate lines.

(25) VOLATILE ORGANIC COMPOUNDS (VOC) is as defined in Rule 102.

(26) WEB-BASED FLARE EVENT NOTIFICATION SYSTEM is a web page that allows facilities to notify the District about flaring events and to enter information such as the time that flaring begins and ends, vent gas flow rates, and emissions.

(c) Requirements

The owner or operator of a petroleum refinery, sulfur recovery plant or hydrogen production plant subject to this rule shall:

(1) Maintain a pilot flame present at all times a flare is operational.

(2) Operate all flares in a smokeless manner with no visible emissions except for periods not to exceed a total of five minutes during two consecutive hours, as determined by the test method in paragraph (j)(2).

(3) Except as specified in (c)(10), operate all general service flares at petroleum refineries such that the flare tip velocity is less than:

(A) 60 feet per second, or the lesser of 400 feet per second and V_{Max}, where:

$$Log_{10}(V_{Max}) = \frac{Net\ Heating\ Value_{Vent\ Gas} + 1{,}212}{850}$$

and the Net Heating $Value_{Vent\ Gas}$ in British Thermal Units per standard cubic foot is determined pursuant to monitoring required in subdivision (g).

(4) Effective January 30, 2019, general service flares at petroleum refineries shall maintain the net heating value of the flare combustion zone gas (NHV_{cz}) at or above 270 British Thermal Units per standard cubic feet, averaged over a 15-minute period. The owner or operator shall calculate NHV_{cz} as specified in Title 40 of the Code of Federal Regulations Part 63 Subpart CC – National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries.

(5) Conduct an annual acoustical or temperature leak survey of all pressure relief devices connected directly to a flare and repair leaking pressure relief devices no later than the next turnaround. The survey shall be conducted no earlier than 90 days prior to the scheduled process unit turnaround.

(6) Conduct a Specific Cause Analysis for any flare event, excluding planned shutdown, planned startup and turnarounds, when any of the thresholds in (c)(6)(A) through (C) is exceeded. Flare events resulting from non-standard

operating procedure during a planned shutdown, planned startup or turnaround, must also conduct a Specific Cause Analysis when any of the thresholds in (c)(6)(A) through (C) is exceeded.

(A) Emissions exceed 100 pounds of VOC; or

(B) Emissions exceed 500 pounds of sulfur dioxide; or

(C) More than 500,000 standard cubic feet of vent gas are combusted.

(7) Effective January 30, 2019, conduct a Specific Cause Analysis for any flare event at a petroleum refinery when the smokeless capacity of the flare is exceeded and either:

(A) The visible emission limits in paragraph (c)(2) or Rule 401 are exceeded; or

(B) The flare tip velocity limits in subparagraph (c)(3)(A) is exceeded.

(8) Submit all Specific Cause Analyses as required by paragraphs (c)(6) or (c)(7) to the Executive Officer within 30 days of the start of the flare event, identifying the cause and duration of the flare event, and any mitigation and corrective actions taken or to be taken to prevent recurrence of a similar event. The owner or operator may request that the Executive Officer grant an extension of up to 15 days to submit the Specific Cause Analysis.

(9) All corrective actions identified in a Specific Cause Analysis required under paragraph (c)(6) or (c)(7) shall be implemented within 45 days of the flare event for which the Specific Cause Analysis was required. A corrective action identified in a Specific Cause Analysis may be implemented more than 45 days after the flare event if justified in a Specific Cause Analysis by showing the required elements in (c)(9)(A):

(A) An implementation schedule to complete the corrective action as soon as practicable, an explanation of the reason(s) why more than 45 days is needed to complete the corrective action, and a demonstration that the implementation schedule is the soonest practicable.

(B) After reviewing the Specific Cause Analysis, the Executive Officer may request additional information justifying why the implementation schedule beyond 45 days is the soonest practical.

(C) Within 30 days of receipt of all information necessary to evaluate the Specific Cause Analysis, the Executive Officer may require a modification to the corrective action or schedule, including increments of progress, and shall notify the operator in writing with an explanation describing why the corrective action is inadequate or the schedule can be shortened.

(10) Effective January 30, 2019, no flare event at a petroleum refinery shall occur above the smokeless capacity of the flare under the following conditions:

(A) When the limits in clauses (c)(10)(D)(i) or (ii) are exceeded and the flare event is due to operator error or poor maintenance.

(B) Two times at a flare in any consecutive three year period, if the flare events exceed the limits in clauses (c)(10)(D)(i) or (ii) and a Specific Cause Analysis shows the same cause for both flare events from the same equipment.

(C) Three times at a flare in any consecutive three year period, if the flare events exceed the limits in clauses (c)(10)(D)(i) or (ii), and the flare events are due to any cause.

(D) Pursuant to subparagraphs (c)(10)(A) through (C), flare events shall not exceed:

(i) The visibility limits in paragraph (c)(2) or Rule 401; or

(ii) The velocity limits in subparagraph (c)(3)(A).

(E) If more than one flare exceeds the limits in (c)(10)(D)(i) or (ii) during a single event, and a Specific Cause Analysis demonstrates that the flaring events at these flares have the same root cause, then one flaring event at each flare shall be considered to have exceeded these limits.

(F) Notwithstanding the provisions in Rule 430 - Breakdown Provisions and Rule 2004 - Requirements, the prohibitions listed in paragraph (c)(10) of this rule shall be applicable during all periods including breakdowns, with the exception of exemptions listed in subdivision (k).

(11) Conduct an analysis and determine the relative cause of any other flare events where more than 5,000 standard cubic feet of vent gas are combusted. When it is not feasible to determine relative cause, state the reason why it was not feasible to make the determination.

(12) Maintain the following information and submit to the Executive Officer upon request:

(A) Detailed process flow diagrams of all upstream equipment and process units venting to each flare and a complete description and technical specifications for each flare system components such as flares, associated knock-out pots, surge drums, water seals and flare gas recovery systems, and an audit of the vent gas recovery capacity of each flare system, the available storage for excess vent gases and the scrubbing capacity available for vent gases, including any limitations associated with scrubbing vent gases for use as a fuel; and

(B) A description of the equipment, processes and procedures installed or implemented within the last five years to reduce flaring; and

(C) A descriptions of any equipment, processes or procedures the owner or operator plans to install or implement to eliminate or reduce flaring. The description shall specify the scheduled year of installation or implementation.

(13) Submit to the Executive Officer 12 months after July 7, 2017 a Scoping Document that evaluates the feasibility of minimizing flaring emissions that includes the following components:

(A) The Scoping Document shall describe how a facility operator or owner can reduce emissions from all planned flare events and essential operational needs flare events, to emission limits specified in subparagraph (c)(13)(B). The Scoping Document shall describe two potential alternatives for each applicable level in (c)(13)(B)(i) through (iv), and shall include an analysis of the following:

(i) proposed physical controls and/or operating practices,

(ii) technical feasibility constraints,

(iii) approximate cost (initial capital and ongoing),

(iv) timing constraints.

(B) The Scoping Document shall analyze the feasibility of achieving each of the following annual emission levels for planned flare events and essential operational needs as soon as feasible:

(i) 0.10 tons of sulfur oxides per million barrels of a petroleum refinery's 2004 calendar year crude processing capacity,

(ii) 0.05 tons of sulfur oxides per million barrels of a petroleum refinery's 2004 calendar year crude processing capacity, and

(iii) 0.01 tons or lower of sulfur oxides per million barrels of a petroleum refinery's 2004 calendar year crude processing capacity, and

(iv) 0.1 tons per year of volatile organic compounds from flares that only vent clean service streams.

(C) Using the criteria described in clauses (c)(13)(A)(i) through (iv), the Scoping Document shall analyze the feasibility of installing and maintaining at least three physical or automated process controls as soon as feasible that can be used together or separately to avoid or minimize emergency flare events described in (c)(13)(C)(i) through (iv).

(i) A sudden influx of vent gas into a flare gas header. The amount of vent gas is equivalent to the highest vent gas flow rate, averaged over a 15-minute period, vented to the flare gas header from all emergency flare events at that flare since January 1, 2012.

(ii) A sudden loss of the process unit with the highest fuel gas consumption rate of recovered flare gas at that facility, averaged over a 15-minute period, since January 1, 2012.

(iii) A sudden loss of all external electrical power to the facility.

(iv) A sudden loss of all electrical power from any non-backup electrical generation unit that is currently operating at a facility.

(D) For each flare operated at the facility, the Scoping Document shall contain a description of:

(i) The smokeless capacity, and documentation for how the smokeless capacity was determined;

(ii) The maximum vent gas flow rate;

(iii) The maximum supplemental gas flow rate;

(iv) Process flow diagram which shows all gas lines that are associated with the flare (e.g., waste, purge, supplemental gases, assist steam);

(v) Detailed process flow diagrams of all associated upstream equipment and process units venting to each flare, with a general description of components, identifying the type and location of each flare and all associated control equipment including but not limited to knockout drums, flare headers, assist, and ignition systems.

(14) Operate all flares in such a manner that minimizes all flaring and that no vent gas is combusted except during emergencies, shutdowns, startups, turnarounds or essential operational needs.

(15) Prevent the combustion in any flare of vent gas with a hydrogen sulfide concentration in excess of 160 ppm, averaged over three hours, excluding any vent gas resulting from an emergency, shutdown, startup, or process upset.

(d) Performance Targets

The owner or operator of a petroleum refinery subject to this rule shall minimize flare emissions and meet a performance target for sulfur dioxide emissions from flares of less than 0.5 tons per million barrels of crude processing capacity, calculated as an average over one calendar year.

(1) Compliance with this performance target shall be determined at the end of each calendar year based on the facility’s annual flare sulfur dioxide emissions normalized over the crude oil processing capacity in calendar year 2004.

(2) In the event the petroleum refinery specific performance target of subdivision (d) is exceeded for any calendar year, the Executive Officer may issue a Notice of Sulfur Dioxide Exceedance that shall become a part of the refinery compliance record.

(3) In the event the petroleum refinery specific performance target of subdivision (d) is exceeded for any calendar year, the owner or operator of the petroleum refinery shall:

(A) Submit a Flare Minimization Plan pursuant to subdivision (e), and

(B) Pay the District mitigation fees, within 90 days following the end of a calendar year for which the performance target was exceeded, according to the following schedule:

(i) If excess emissions are no more than ten percent of the petroleum refinery specific performance target, $25,000 per ton for all sulfur dioxide emission(s) in excess of the applicable performance target, or

(ii) If excess emissions are greater than ten percent but no more than twenty percent of the petroleum refinery specific performance target, $50,000 per ton of all sulfur dioxide emission(s) in excess of the applicable performance target, or

(iii) If excess emissions are greater than twenty percent of the petroleum refinery specific performance target, $100,000 per ton of all sulfur dioxide emission(s) in excess of the applicable performance target.

(e) Flare Minimization Plan

(4) The owner or operator of a petroleum refinery exceeding the performance target in subdivision (d) shall submit, no later than 90 days after the end of a calendar year with emissions exceeding the annual performance target, a complete Flare Minimization Plan for approval by the Executive Officer. This plan shall constitute a plan pursuant to Rule 221 and fees shall be assessed pursuant to Rule 306. The plan application shall list all actions to be taken by the petroleum refinery to meet the performance target in subdivision (d), and shall include the following information:

(A) A complete description and technical specifications for each flare and associated knock-out pots, surge drums, water seals and flare gas recovery systems;

(B) Refinery policies and procedures to be implemented and any equipment improvements to minimize flaring and flare emissions and comply with the performance target of subdivision (d) for:

(i) Planned turnarounds and other scheduled maintenance, based on an evaluation of these activities during the previous five years;

(ii) Essential operational needs and the technical reason for which the vent gas cannot be prevented from being flared during each specific situation, based on supporting documentation on flare gas recovery systems, excess gas storage and gas treating capacity available for each flare; and

(iii) Emergencies, including procedures that will be used to prevent recurring equipment breakdowns and process upsets, based on an evaluation of the adequacy of maintenance schedules for equipment, process and control instrumentation.

(C) Any flare gas recovery equipment and treatment system(s) to be installed to comply with the performance targets of subdivision (d).

(5) The Executive Officer will make the Flare Minimization Plans available for public review for a period of 60 days and respond to comments received prior to plan approval. The Executive Officer will approve a plan upon determining that it meets the requirements of subdivision (e), or notify the owner or operator in writing that the plan is deficient and specify the required corrective action. If the owner or operator fails to submit an amendment within 45 days to correct the deficiency, the Executive Officer will deny the Flare Minimization Plan. The facility shall be deemed in violation of this rule upon the Executive Officer's denial of the Flare Minimization Plan.

(6) The owner or operator of a petroleum refinery having an existing approved Flare Minimization Plan shall, no later than 90 days after the end of a calendar year, submit for the approval of the Executive Officer a revised Flare Minimization Plan, subject to the provisions of paragraphs (e)(1) and (e)(2), in the event the annual performance target for that calendar year is exceeded.

(7) The owner and operator of a petroleum refinery shall comply with all provisions of an approved Flare Minimization Plan. Violation of any of the terms of the plan is a violation of this rule.

(f) Flare Monitoring and Recording Plan Requirements

(1) The owner or operator of an existing petroleum refinery, sulfur recovery plant or hydrogen production plant, upon modification or replacement of any monitoring equipment included in an approved Flare Monitoring and Recording Plan shall submit a revised Flare Monitoring and Recording Plan, complete with an application and appropriate fees, for each facility to the Executive Officer for approval. This plan shall constitute a plan pursuant to Rule 221 and fees shall be assessed pursuant to Rule 306. Each Flare Monitoring and Recording Plan shall contain the information described in paragraph (f)(4) of this rule.

(2) The owner or operator of an existing petroleum refinery, sulfur recovery plant or hydrogen production plant shall:

(A) Comply with the most current Flare Monitoring and Recording Plan approved by the Executive Officer. The current plan shall remain in effect until any revised Flare Monitoring and Recording Plan, submitted pursuant to paragraph (f)(1) is approved by the Executive Officer.

(B) The owner or operator of a petroleum refinery, sulfur plant or hydrogen plant shall comply with all provisions of an approved Flare Monitoring and Recording Plan. Violation of any of the terms of the plan is a violation of this rule.

(3) The owner or operator of a new or an existing non-operating petroleum refinery, sulfur recovery plant or hydrogen production plant starting or restarting operations that were not shut down from a turnaround or other shut-down as part of normal operations on or after July 7, 2017 shall:

(A) Provide the Executive Officer a written notice of the date of start-up no later than seven (7) days prior to starting or commencing operations.

(B) No later than 180 days prior to the initial startup or resumption of operations, submit a complete application and appropriate fees for a Flare Monitoring and Recording Plan to the Executive Officer for approval. This plan shall constitute a plan pursuant to Rule 221 and fees shall be assessed pursuant to Rule 306. Each Flare Monitoring and Recording Plan shall contain the information described in paragraph (f)(4) of this rule.

(4) Each Flare Monitoring and Recording Plan shall include, at a minimum, the following:

(A) A facility plot plan showing the location of each flare in relation to the general plant layout.

(B) Type of flare service, as defined in paragraph (b)(4), and information regarding design capacity, operation and maintenance for each flare.

(C) The following information regarding pilot and purge gas for each flare:

(i) Type(s) of gas used;

(ii) Actual set operating flow rate in standard cubic feet per minute;

(iii) Maximum total sulfur concentration expected for each type of gas used; and

(iv) Average higher (gross) heating value expected for each type of gas used.

(D) Drawing(s), preferably to scale with dimensions, and an as-built process flow diagram of the flare(s) identifying major components, such as flare header, flare stack, flare tip(s) or burner(s), any bypass line, purge gas system, pilot gas system, ignition system, assist system, water seal, knockout drum and molecular seal.

(E) Detailed process flow diagrams identifying the type and location of each flare and all associated control equipment including but not limited to knockout drums, flare headers, assist, and ignition systems, and a representative flow diagram showing the interconnections of the flare system(s) with vapor recovery system(s), process units and other equipment as applicable.

(F) A complete description of the assist system process control, flame detection system and pilot ignition system.

(G) A complete description of the gas flaring process for an integrated gas flaring system which describes the method of operation of the flares (e.g. sequential, etc.).

(H) A complete description of the flare gas recovery system and vapor recovery system(s) which have interconnection to a flare, such as compressor description(s), design capacities of each compressor and the vapor recovery system, and the method currently used to determine and record the amount of vapors recovered.

(I) Drawing(s) with dimensions, preferably to scale, showing the following information for proposed vent gas:

(i) Sampling locations; and

(ii) Flow meter device(s), on/off flow indicators, higher heating value analyzer, and total sulfur analyzer locations and the method used to determine the location.

(J) A detailed description of manufacturer’s specifications, including but not limited to, make, model, type, range, precision, accuracy, calibration, maintenance, a quality assurance procedure and any other specifications and information referenced in Attachment A for all existing and proposed flow metering devices, on/off flow indicating devices, higher heating value and total sulfur analyzers for vent gas.

(K) A complete description and the data used to determine and to set the actuating and de-actuating and the method to be used for verification of each setting for each on/off flow indicator.

(L) A complete description of proposed analytical and sampling methods or estimation methods, if applicable, for determining higher (gross) heating value and total sulfur concentration of the flare vent gas.

(M) A complete description of the proposed data recording, collection, management, and any other specifications and information referenced in Attachment A for each flare monitoring system.

(N) A complete description of proposed method to determine, monitor and record total volume, higher heating value, and total sulfur concentration of gases vented to a flare for each flare event pursuant to the requirements of this rule.

(O) For new or existing non-operating petroleum refinery, sulfur recovery plant or hydrogen production plant starting or restarting operations, other than from standard turnarounds or process unit shut-downs, on or after July 7, 2017, a schedule for the installation and operation of each flare monitoring system.

(P) A complete description of any proposed alternative criteria to determine a sampling flare event for each specific flare, if any, and detailed information used for the basis of establishing such criteria.

(g) Operation, Monitoring and Recording Requirements

The owner or operator of a flare subject to this rule shall comply with the following:

(1) On or before six (6) months after approval of the Flare Monitoring and Recording Plan or Revised Flare Monitoring and Recording Plan, start monitoring and recording in accordance with subdivision (g) and the provisions in the approved Flare Monitoring and Recording Plan or Revised Flare Monitoring and Recording Plan.

(2) Notwithstanding the provisions in Rule 430 - Breakdown Provisions and Rule 2004 - Requirements, the Operation Monitoring and Recording Requirements of this rule shall be applicable during all periods including breakdowns except as specified in paragraph (g)(5)(A).

(3) Perform monitoring and recording of the operating parameters, as applicable, according to the monitoring and recording requirements and

frequency shown in Table 1 (including footnotes) below, except as specified in paragraph (g)(4) and (g)(5).

TABLE 1

TYPE OF FLARE	OPERATING PARAMETER	MONITORING AND RECORDING
Clean Service	Gas Flow[1]	Measured and Recorded[2] Continuously with Flow Meter(s) and/or On/Off Flow Indicator(s)
	Gas Higher Heating Value [3]	Calculated or Continuously Measured and Recorded with a Higher Heating Value Analyzer
	Total Sulfur Concentration[4]	Calculated or Semi-Continuously Measured and Recorded with a Total Sulfur Analyzer
General Service	Gas Flow[1]	Measured and Recorded[2] Continuously with Flow Meter(s) with or without on/off flow indicator(s)
	Gas Higher Heating Value [3]	Continuously Measured and Recorded with a Higher Heating Value Analyzer
	Total Sulfur Concentration[4]	Semi-Continuously Measured and Recorded with a Total Sulfur Analyzer

1. Standard Cubic Feet per Minute.
2. All flow meters, flow indicators and recorders shall meet or exceed the minimum specifications in Attachment A.
3. Higher (Gross) Heating Value in British Thermal Units per Standard Cubic Foot.
4. Total Sulfur as SO_2, ppmv.

(4) Alternative Flare Vent Gas Sampling

(A) In cases where sampling of vent gas is exempted pursuant to paragraph (k)(1), the owner or operator of a gas flare shall identify for each flare event, the cause of event, the process system(s) involved, date and time event started and duration and any other information related to the type of vent gas (e.g. total sulfur concentration) which is necessary to calculate flare emissions using the guidelines in Appendix B for substituted data. The estimated emissions, subject to approval by the Executive Officer as representative of emissions from that flare event, shall be reported and submitted with the quarterly report as specified in paragraph (i)(4).

(5) Flare Monitoring System

(A) Maintain any flare monitoring system, used to ensure compliance with paragraph (g)(3) of this rule, in good operating condition at all times when the flare that it serves is operational, except when out of service due to:

(i) Breakdowns and unplanned system maintenance, which shall not exceed 96 hours, cumulatively, per quarter for each reporting period; or,

(ii) Planned maintenance, which shall not exceed 14 days per 18 month period commencing the start of flare monitoring and recording, provided that a written notification detailing the reason for maintenance and methods that will be used during the maintenance period to determine emissions associated with flare events is provided to the Executive Officer prior to, or within 24 hours of, removal of the monitoring system from service.

(B) A flare monitoring system may be used to measure and record the operating parameters required in paragraph (g)(3) of this rule for more than one flare provided that:

(i) All the gases being measured and recorded are delivered to the flare(s) for combustion; and,

(ii) If the flare monitoring system is used to measure and record the operating parameters for general service flares, the flare monitoring system shall consist of a continuous vent gas flow meter, a continuous higher heating value analyzer, a total sulfur analyzer and recorder that meet the requirements specified in Attachment A.

(6) Monitor the presence of a pilot flame using a thermocouple or any other equivalent device approved by the Executive Officer to detect the presence of a flame.

(7) Monitor all flares for visible emissions using color video monitors with date and time stamp, capable of recording a digital image of the flare and the flame of flares that are not enclosed, at a rate of no less than one frame per minute. Effective January 30, 2019, monitor all flares for visible emissions using color video monitors with date and time stamp, capable of recording a digital image of the flare, the flame of flares that are not enclosed, and a sufficient area above the flame of all flares that is suitable for visible emissions observations, at a rate of no less than one frame every 15 seconds.

(8) All general service flares shall:

(A) Have a flow meter installed in a manner and at a location that would allow for accurate measurements of the total volume of vent gas to each flare. If the flow meter cannot be placed in the location that would allow for accurate measurement due to physical constraints, the operator shall retrofit or equip the existing flow meters with totalizing capability to indicate the true net volume of gas flow to each flare.

(B) Monitor and record the pilot gas and purge gas flow to each flare using a flow meter or equivalent device approved by the Executive Officer.

(9) No later than January 30, 2019, for all general service flares:

(A) Install, operate, calibrate, maintain, and record data from any monitoring systems required by Title 40 of the Code of Federal Regulations Part 63 Subpart CC – National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries that are not already required by paragraph (g).

(h) Recordkeeping Requirements

The owner or operator of a flare shall maintain records in a manner approved by the Executive Officer for a period of five (5) years for all the information required to be monitored under paragraphs (g)(3), (g)(4), (g)(5), (g)(6), (g)(7), (g)(9), and subparagraph (g)(8)(B) as applicable and make such records available to the Executive Officer upon request.

(i) Notification and Reporting Requirements

The owner or operator of a flare shall:

(1) Provide a 24 hour telephone service for access by the public for inquiries about flare events. The owner or operator shall provide the Executive Officer in writing the name and number of the initial contact and any contact update.

(2) Notify the Executive Officer via the Web-Based Flare Event Notification System within one hour from the start of any unplanned flare event with emissions exceeding either 100 pounds of VOC or 500 pounds of sulfur dioxide, or exceeding 500,000 standard cubic feet of flared vent gas.

(3) Notify the Executive Officer via the Web-Based Flare Event Notification System at least 24 hours prior to the start of a planned flare event with emissions exceeding either 100 pounds of VOC or 500 pounds of sulfur dioxide, or 500,000 standard cubic feet of combusted vent gas. Within one hour of the start of a planned flare event, submit a notification via the Web-Based Flare Event Notification System, referencing the notification number assigned to the planned flare event at the time of the original notification.

(4) Notify the Executive Officer via the Web-Based Flare Event Notification System within one hour after the cumulative daily total amount of flare gas vented from a flare exceeds 100,000 standard cubic feet, if a notification has not already been provided for that day pursuant to paragraphs (i)(2) or (i)(3).

(5) If the Web-Based Flare Event Notification System is not available, or if functions within the Web-Based Flare Event Notification System do not allow facilities to enter the necessary information required in (i)(2) through (i)(4), then notifications shall be made to 800-CUT-SMOG (800-288-7664).

(6) Submit a quarterly report in an electronic format approved by the Executive Officer within 30 days after the end of each quarter. Each quarterly report shall be certified for accuracy in writing by the responsible facility official and shall include the following:

(A) The information required to be monitored under paragraphs (g)(3), (g)(4), (g)(5), (g)(6), and (g)(9), and subparagraph (g)(8)(C) of this rule. Notwithstanding the January 30, 2019 compliance date in paragraph (g)(9), data collected pursuant to paragraph (g)(9) shall be made available in the first quarterly report after the applicable monitors have been certified.

(B) The total daily and quarterly emissions of criteria pollutants from each flare and each flare event along with all information used to calculate the emissions, which includes standard volumes, higher heating values and total sulfur concentration of the vent gases, event duration and emission factors. Identify each reported value of flow rate, higher heating values or sulfur concentration reported using Data Substitution Procedures in Attachment B, and identify the data substitution method used and the date the method was approved by the Executive Officer, if applicable.

(i) Emissions from flares shall be calculated using the Emissions Calculation Procedures outlined in Attachment B: Guidelines for Emissions Calculations.

(ii) During all down time periods of the monitoring system, emissions shall be calculated using the Missing Data Substitution Procedures outlined in Attachment B: Guidelines for Emissions Calculations.

(C) The description of the cause of each flare event as analyzed pursuant to paragraphs (c)(6), (c)(7), and (c)(11) and the category of flare event such as emergency, shutdown, startup or essential operational need or other specific cause(s), and the associated emissions.

(D) Records of annual acoustical or temperature leak survey conducted pursuant to paragraph (c)(5). The record shall include identification of all valves inspected, date of inspections, and the name of the person(s) conducting the inspections.

(E) Flare monitoring system downtime periods, including dates and times and explanation for each period.

(F) A copy of written notices for all reportable air releases related to any flare event, as required by 40 CFR, Part 302 - Designation, Reportable Quantities, and Notification and 40 CFR, Part 355 - Emergency Planning and Notification, if applicable.

(j) Testing and Monitoring Methods

(1) For the purpose of this rule, the test methods listed below shall be used:

(A) The higher (gross) heating value of vent gases shall be determined by:

(i) ASTM Method D4809-13, ASTM Method D 3588-98(2011), ASTM Method D4891-13, or other ASTM standard as approved by the Executive Officer, California Air Resources Board and U.S. Environmental Protection Agency; and

(ii) With a higher heating value analyzer that meets or exceeds the specifications in Attachment A.

(B) The total sulfur concentration, expressed as sulfur dioxide, shall be determined by:

(i) District Method 307-91 or ASTM Method D 5504-12, or other ASTM standard as approved by the Executive Officer, California Air Resources Board and U.S. Environmental Protection Agency; and

(ii) With a total sulfur analyzer that meets or exceeds the specifications in Attachment A.

(C) The vent gas flow shall be determined by a flow measuring device that meets or exceeds the specifications described in Attachment A, as applicable. The accuracy of all flow meters shall be verified every twelve months according to the manufacturers' procedures and the results shall be submitted to the Executive Officer within 30 days after the reports are issued.

(2) Visible emissions pursuant to paragraph (c)(2) shall be determined by US EPA Method 22, 40 CFR Part 60 Appendix A.

(3) Notwithstanding paragraph (j)(1), continuous monitoring systems certified under Rule 2011 - Requirements for Monitoring, Reporting and Recordkeeping of Oxides of Sulfur (SOx) Emissions and Rule 2012 - Requirements for Monitoring, Reporting and Recordkeeping of Oxides of Nitrogen (NOx) Emissions, may be used for the monitoring of vent gases.

(k) Exemption

(1) Notwithstanding a flare monitoring system, consisting of a flow meter, higher heating value analyzer, net heating value analyzer and total sulfur analyzer that is in operation, sampling and analyses of representative samples for higher heating values, net heating values, and total sulfur concentration pursuant to paragraph (g)(3) may not be required for any flare event that:

(A) Is a result of a catastrophic event including a major fire or an explosion at the facility such that collecting a sample is infeasible or constitutes a safety hazard, or

(B) Constitutes a safety hazard to the sampling personnel at the sampling location approved in the Flare Monitoring and Recording Plan during the entire flare event, provided that a sample is collected at an alternative location where it is safe as determined by the facility owner or operator. The owner or operator shall demonstrate to the Executive Officer that the sample collected at an alternative location is representative of the flare event.

(2) Any sulfur dioxide emissions, visible emissions prohibited in paragraph (c)(10), and flare tip velocities that exceed limits in subparagraph (c)(3)(A) from flare events caused by external power curtailment beyond the operator’s control (excluding interruptible service agreements), natural disasters or acts of war or terrorism shall not count towards either:

(A) The performance targets specified in subdivision (d) upon submittal of documentation proving the existence of such events and certified in writing by the petroleum refinery official responsible for emission reporting; or

(B) The prohibitions listed in paragraph (c)(10).

ATTACHMENT A

FLARE MONITORING SYSTEM REQUIREMENTS

The components of each flare monitoring system must meet or exceed the minimum specifications listed below. Components with other specifications may be used provided the owner or operator of a gas flare can demonstrate that the specifications are equivalent and has been approved by the Executive Officer.

1. Continuous Flow Measuring Device

The monitor must be sensitive to rapid flow changes, and have the capability of reporting both instantaneous velocity and totalized flow. Materials exposed to the flare gas shall be corrosion resistant. If required by the petroleum refinery or the hydrogen production plant, the manufacturer must provide an enclosure with an area classification rating of Class 1, Division 2, Groups A, B, C, D, and is FM and CSA approved. The monitor shall (i) feature automated daily calibrations at low and high ranges, and (ii) shall signal alarms if the calibration error or drift is exceeded, provided that the monitor is equipped with such capability. The volumetric flow measuring device may consist of one or more flow meters, and, as combined, shall meet the following specifications.

Velocity Range:	0.1-250 ft/sec
Repeatability:	± 1% of reading over the velocity range
Accuracy:	± 20% of reading over the velocity range of 0.1-1 ft/s and ± 5% of reading over the velocity range of 1-250 ft/s
Installation:	Applicable AGA, ANSI, API, or equivalent standard; hot tap capability. If applicable, the manufacturer must specify the straight-run pipe requirements in terms of the minimum upstream and downstream distances from the nearest flow disturbances to the device
Flow Rate Determination:	Must be corrected to one atmosphere pressure and 68^0 F and recorded as one-minute averages
Data Records	Measured continuously and recorded over one-minute averages. The instrument shall be capable of storing or transferring all data for later retrieval
QA/QC	Shall comply with the flow QA/QC requirements of District Rule 218.1. An annual verification of accuracy

is required, and shall be specified by the manufacturer. Note: A flow RATA is generally infeasible due to safety concerns

2. On/Off Flow Indicator

The on/off flow indicator is a device which is used to demonstrate the flow of vent gas during a flare event, and shall meet or exceed specifications as approved by the Executive Officer. The on/off flow indicator setting shall be verifiable.

3. Data Recording System

All data as generated by the above flow meters and the on/off flow indicators must be continuously recorded by strip chart recorders or computers. The strip chart must have a minimum chart width of 10 inches, a readability of 0.5% of the span, and a minimum of 100 chart divisions. The computer must have the capability to generate one-minute average data from that which is continuously generated by the flow meters and the on/off limit switch.

4. Continuous and Semi-continuous Gaseous Stream Higher Heating Value (HHV) Flare Monitoring Systems

The following is intended to ensure that verifiable, meaningful, and representative data are collected from continuous and semi-continuous gaseous stream HHV flare measurement monitoring devices systems. All procedures are subject to Executive Officer review and approval.

General Requirements:

a. The monitoring system must be capable of measuring HHV within the requirements of the rule.

b. The monitoring system must be capable of adjusting to rapid changes in HHV within a reasonable time meeting the definition of a continuous or semi-continuous monitoring system as defined in the applicable rule and as approved by the Executive Officer.

c. Monitoring system sampling interfaces and analyzers in contact with sample gas must be compatible with sample gases and able to resist flow temperatures and pressures.

d. The sampling inlet system interface must be heated as necessary so as to prevent condensation.

e. Sample gas must be conditioned such that the sample is free of particulate or liquid matter.

f. The sample must flow without impediment through the instrument sampling system sampling interface and analyzer.

g. Use an enclosure with an area classification rating of Class 1, Division 2, Groups A, B, C, D, and is FM or CSA approved. The enclosure must be able to maintain a stable analyzer temperature as required for analyzer performance.

h. The monitoring system must feature automated daily calibrations calibration checks, minimally at mid-range, and preferably at both applicable Federal minimum BTU requirements (low end) and 95% of full scale (high end) ranges at low and high ranges

i. The monitoring system analyzer must include an output compatible with a Data Acquisition System (DAS) or similar system that can process data generated by the analyzer and record the results. A data recorder compatible with analyzer output and capable of recording analyzer output must be supplied with the instrument.

j. Each monitoring system must have a written quality assurance/quality control (QA/QC) plan approved by the Executive Officer and available for District inspection.

k. Maintain a maintenance log for each monitoring system.

l. Perform routine maintenance and repair as recommended by the manufacturer or according to a standard operating procedure submitted and approved by the Executive Officer.

m. The placement and installation of monitoring systems is critical for collecting representative information on HHV gas content. Factors that should be considered in placement of a sampling interface include but are not limited to safety, ensuring the sample is representative of the source, ease of placement and access. Sampling interfaces, conditioning systems and enclosures may be shared with other instrumentation, if appropriate.

n. Perform at monitoring system start-up and on an annual basis a relative accuracy test audit (RATA) which is the ratio of the sum of the absolute mean difference between the monitoring system generated data and the value determined using ASTM D1945-03 and ASTM D3588-91, ASTM D

4891-89, or other ASTM standard as approved by the Executive Officer, California Air Resources Board and U.S. Environmental Protection Agency. See rule 218.1 (a)(23) for calculations.

o. Periodically perform a calibration curve or linearity verification error test according to permitting conditions and or on a schedule approved by the Executive Officer. Typically, this calibration curve will be prepared from standards representing a:

   i. 10-30 percent of the measurement range

   ii. 40-60 percent of the measurement range

   iii. 80-100 percent of the measurement range

p. Analyzers with auto calibration check capability should be checked daily unless a different calibration frequency is approved by the Executive Officer. For analyzers without auto calibration check capability, submit a calibration check frequency request including supporting documentation to the Executive Officer for comment and approval.

q. Periodically perform a zero drift test. Allowed zero drift should be consistent with a properly operating system. See rule 218.1 (a)(32) for calculations.

r. Retain records on the valid data return percentage.

s. Retain records on the availability or up-time of the monitoring system.

t. Retain records on the breakdown frequency and duration of the breakdown.

u. Retain records on excursions beyond quality control limits stated in the QA plan.

5. Continuous and Semi-continuous Gaseous Stream Total Sulfur Monitoring Systems

The following is intended to ensure that verifiable, meaningful, and representative data are collected from continuous and semi-continuous gaseous stream sulfur monitoring systems. All procedures are subject to Executive Officer review and approval.

General Requirements

a. The monitoring system must be capable of measuring total sulfur concentration within the requirements of the rule.

b. The monitoring system must be capable of adjusting to rapid changes in sulfur concentration within a reasonable time as defined in the applicable rule and as approved by the Executive Officer.

c. Monitoring system in contact with sample gas must be inert to sulfur gases and resistant to corrosion.

d. The sampling inlet system interface system must be heated as necessary so as to prevent condensation.

e. Sample gas must be conditioned such that the sample is free of particulate or liquid matter.

f. The sample must flow without impediment through the instrument sampling system sampling interface and analyzer.

g. Use an enclosure with an area classification rating of Class 1, Division 2, Groups A, B, C, D, and is FM or CSA approved. The enclosure must be able to maintain a stable analyzer temperature as required for analyzer performance.

h. The monitoring system must feature automated daily calibrations at low and high ranges, and shall signal alarms if the calibration error or drift is exceeded.

i. The monitoring system must include a Data Acquisition System (DAS) or similar system that can process data generated by the analyzer and record the results.

j. Each monitoring system must have a written quality assurance/quality control (QA/QC) plan approved by the Executive Officer and available for District inspection.

k. Maintain a maintenance log for each monitoring system.

l. Perform routine maintenance as recommended by the manufacturer or according to a standard operating procedure submitted and approved by the Executive Officer.

m. The placement and installation of monitoring systems is critical for collecting representative information on total sulfur gas concentration. Factors that should be considered in placement of a sampling interface include but are not limited to safety, ensuring the sample is representative of the source, ease of placement and access. Sampling interfaces, conditioning systems and enclosures may be shared with other instrumentation, if appropriate.

n. Perform at monitoring system start-up and on an annual basis a relative accuracy test audit (RATA) which is the ratio of the sum of the absolute mean difference between the monitoring system generated data and the value determined using SCAQMD Laboratory Method 307-91, ASTM D5504-01 or other ASTM standard as approved by the Executive Officer, California Air Resources Board and U.S. Environmental Protection Agency. See rule 218.1(a)(23) for calculations.

Note: Facilities are reminded that there are many critical issues for the collection of representative and monitoring system comparable gas samples destined for Method 307-91 or ASTM D5504-01 analysis.

o. Facilities are strongly encouraged to use calibration gases prepared using a NIST hydrogen sulfide SRM, Nederlands Meetinstituut NMi or a NTRM standard as the primary reference.

p. Periodically perform a calibration curve or linearity verification performed according to permitting conditions and/or on a schedule approved by the Executive Officer. Typically, this calibration curve will be prepared from standards representing:

i. 10 to 30 percent of the measurement range

ii. 40 to 60 percent of the measurement range

iii. 80 to 100 percent of the measurement range

q. Analyzers with auto calibration capability shall be calibrated daily unless a different calibration frequency is approved by the Executive Officer. For analyzers without auto calibration capability, submit a calibration frequency request, including supporting documentation to the Executive Officer for comment and approval.

r. Seven Day Calibration Error Test shall be performed by evaluating the analyzer performance over seven consecutive days as necessary. The calibration drift should not exceed five percent of the full-scale range.

s. Analyze daily a control or drift test sample or standard. Adequate system analyzer performance is demonstrated by recoveries of 90 to 110 percent of the theoretical amounts for total reduced sulfur species in the test gas.

t. Periodically perform an analyzer blank test to evaluate the presence of analyzer leaks or wear on sample valves and related components. Replace components as necessary to restore the analyzer to nominal function. A blank should yield results below the monitoring plan approved lower measurement range.

u. Periodically perform a zero drift test. Allowed zero drift should be consistent with a properly operating system analyzer. See rule 218.1(a)(32) for calculations.

v. Retain records on the valid data return percentage.

w. Retain records on the availability or up-time of the monitoring system.

x. Retain records on the breakdown frequency and duration of the breakdown.

y. Retain records on excursions beyond quality control limits stated in the QA plan.

Gas Chromatograph (GC) Based System Analyzer Specific Requirements

a. The following performance tests specific to GC based sulfur analyzers are part of an overall QA program. This list is not all inclusive. The specific performance tests that are required under rule compliance will be based upon analyzer configuration, data requirements, practical concerns such as safety and are subject to approval by the Executive Officer.

i. Whenever a calibration is performed and whenever a calibration drift test is performed, examine retention times for each calibration component. Compare the retention times against historically observed retention times. Retention time drift should be better than within five percent. Compare the retention times to analyzer and DAS parameters such as time gates to ensure compatibility. These parameters including the analysis time may need to be updated on occasion.

ii. Verify daily that the analyzer response drift for individual sulfur species does not exceed ten percent of the control information.

Total Sulfur Analyzer System Requirements

a. The following performance tests specific to total sulfur based analyzers are part of an overall QA program. This list is not all inclusive. The specific performance tests that are required under rule compliance will be based upon instrument analyzer configuration, data requirements, practical concerns such as safety and are subject to approval by the Executive Officer.

i. Verify daily that the analyzer response drift for the concentration of total sulfur, expressed as sulfur dioxide does not exceed ten percent of the control information.

ATTACHMENT B

GUIDELINES FOR CALCULATING FLARE EMISSIONS

The following methods shall be used to calculate flare emissions. An alternative method may be used, utilizing facility-specific data such as monitoring and/or gas composition data, provided it has been approved as equivalent in writing by the Executive Officer.

1. Emission Calculation Procedures

Petroleum refinery, sulfur recovery plant or hydrogen production facility operators shall use the following equations and emission factors to calculate emissions from vent gas, natural gas, propane and butane:

Effective No Later Than January 30, 2019, or As Soon As Monitors Are Installed and Certified That Can Measure Net Heating Value

Vent Gas

Air Pollutant	Equation	Emission Factor
ROG	E = V x NHV x EF	0.66 lb/mmBTU
NOx[1]	E = V x HHV x EF	0.068 lb/mmBTU
CO	E = V x NHV x EF	0.31 lb/mmBTU
PM10	E = V x EF	21 lb/mmSCF
SOx	E = V x Cs x 0.1662	Note (2)

Effective Until January 30, 2019, or Until Monitors Are Installed and Certified That Can Measure Net Heating Value

Air Pollutant	Equation	Emission Factor
ROG	E = V x HHV x EF	0.063 lb/mmBTU
NOx[1]	E = V x HHV x EF	0.068 lb/mmBTU
CO	E = V x HHV x EF	0.37 lb/mmBTU
PM10	E = V x EF	21 lb/mmSCF
SOx	E = V x Cs x 0.1662	Note (2)

Where:

E = Calculated vent gas emissions (lbs)

V= Volume flow of vent gas, as measured in million standard cubic feet at 14.7 psia and 68^0 Fahrenheit

HHV = Higher Heating Value, as measured in British Thermal Unit per standard cubic foot

NHV = Net Heating Value, as measured in British Thermal Units per standard cubic foot

EF = Emission Factor

Cs = The concentration of total sulfur in the vent gas, expressed as sulfur dioxide, as measured in part per million by volume using the methods specified in this rule.

Note (1) For vent gas streams of pure hydrogen, only the emission factor for NOx should be used.

Note (2) If an approved total sulfur analyzer is used in accordance with this rule, Cs is the concentration of total sulfur in the vent gas, averaged over 15 minutes or less, if the event duration is shorter than 15 minutes.

Natural Gas

Air Pollutant	Equation	Emission Factor (lb/mmSCF)
ROG	E = V x EF	7
NOx	E = V x EF	130
CO	E = V x EF	35
PM10	E = V x EF	7.5
SOx	E = V x EF	0.83

Propane and Butane

Air Pollutant	Equation	Emission Factor (lb/mmBTU)
ROG	E = V x 3500 x EF	0.009
NOx	E = V x 3500 x EF	0.145
CO	E = V x 3500 x EF	0.082
PM10	E = V x 3500 x EF	0.002
SOx(1)	E = V x 3500 x EF	0.047

Note (1) If the concentration of total sulfur in the vent gas or in the process streams vented to the flare is measured, the operator shall use E = V x Cs x 0.1662 to estimate the SOx emissions.

Single On/Off Flow Indicator Switch

The flow rate setting of the on/off flow indicator switch if the switch is not actuated or the maximum design capacity of the flare for the flow rate for each flare event.

Multiple On/Off Flow Indicator Switch

a) The flow rate setting of the first stage on/off flow indicator switch if the switch is not actuated.

b) When an on/off switch is actuated assume the flow rate is the flow rate that would actuate the on/off switch set at the next highest flow rate.

c) Use the maximum design capacity of the flare for the flow rate when the on/off switch set for the highest flow rate is actuated.

Flow Meters Only

a) Use the recorded flow meter data until the maximum range is exceeded.

b) When the maximum range of the flow meter is exceeded, assume the flow rate is the maximum design capacity of the flare(s), unless the owner or operator demonstrates and the Executive Officer approves a calculated flow based upon operational parameters and process data that represent the flow during the period of time that the flow exceeded the maximum range of the flow meter.

c) When the flow rate is below the valid lower range of the flow meter, assume the flow rate is at the lower range.

Combination of Flow Meters and On/Off Flow Indicator Switches

a) Use the recorded flow meter data until the maximum range is exceeded.

b) When the maximum range of the flow meter is exceeded, assume the flow rate is the flow rate that would actuate the on/off switch set at the next highest flow rate.

c) Use the maximum design capacity of the flare for the flow rate when the on/off switch set for the highest flow rate is actuated.

d) When the flow rate is below the valid lower range of the flow meter, assume the flow rate is at the lower range.

e) When the flow rate is below the valid lower range of the flow meter and the set flow rate of an on/off switch, assume the flow rate is the flow rate that would actuate the on/off switch.

2. Data Substitution Procedures

For any time period for which the vent gas flow, the higher heating value or the total sulfur concentration, expressed as sulfur dioxide, are not measured, analyzed and recorded pursuant to the requirements of this rule, unless the owner or operator of a petroleum refinery, sulfur recovery plant or hydrogen production plant demonstrates using verifiable records of flare water seal level and/or other parameters as approved by the Executive Officer in the Flare Monitoring and Recording Plan or the Revised

Flare Monitoring and Recording Plan that no flare event occurred during the period these parameters were not measured, analyzed or recorded, the operator shall substitute and report the following values:

a) If the flow rate is not measured or recorded for any flare event, the totalized flow shall be calculated from the methodology in section 2(a)(i) below, unless the Executive Officer approves the method specified in Section 2(a)(ii).

i) The totalized flow shall be calculated from the product of the flare event duration and the estimated flow rate. The flow rate shall be calculated using the following equation for the period of time the flow meter was out of service:

$$FR = Max.\ FR - 0.5(Max.\ FR - Avg.\ FR)$$

Where:

FR = Estimated Flow Rate (standard cubic feet per minute)

Max FR = Maximum flow rate that was measured and recorded for that flare during the previous 20 quarters preceding the flare event. This maximum value is based on the average flow rate during an individual flare event, not an instantaneous maximum value.

Avg FR = Average flow rate for all measured and recorded flow rates for all sampled flare events for that flare, during the previous 20 quarters preceding the subject flare event.

The duration of a flare event during periods when the flow meter is out of service shall be determined using an alternate method approved by the Executive Officer in the Flare Monitoring and Recording Plan or Revised Flare Monitoring and Recording Plan.

In the absence of an approved alternate method to determine the duration of the flare event during periods when the flow meter is out of service, the operator shall report the flare to be venting for the entire time the flow meter is out of service.

ii) Alternate methods using recorded and verifiable operational parameters and/or process data, including reference to similar events that have previously occurred, approved by the Executive Officer to be representative of the volume of vent gas, may be used to determine the flow rate in lieu of the method specified above.

b) If the higher heating value is not measured or recorded for any flare event pursuant to the requirements of this rule, the higher heating value shall be calculated from the methodology in section 2(b)(i) below, unless the Executive Officer approves the method specified in Section 2(b)(ii).

i) The higher heating value shall be calculated using the following equation for the period of time this parameter was not measured or recorded:

$$HHV = Max\ HHV - 0.5(Max\ HHV - Avg\ HHV)$$

Where:

HHV	=	Estimated higher heating value (Btu/scf)
Max HHV	=	Maximum HHV measured and recorded for that flare during the previous 20 quarters preceding the flare event.
Avg HHV	=	Average value of all HHV measured and recorded for that flare for all sampled flare events during the previous 20 quarters preceding the flare event.

ii) Alternate methods using recorded and verifiable operational parameters, sampled data, and/ or process data, including reference to similar events that have previously occurred, approved by the Executive Officer to be representative of the HHV of the vent gas, may be used to determine the HHV in lieu of the method specified above.

c) If the total sulfur concentration, expressed as sulfur dioxide, is not measured or recorded for any flare event pursuant to the requirements of this rule, it shall be calculated from the methodology in section 2(c)(i) below, unless the Executive Officer approves the method specified in Section 2(c)(ii).

i) The total sulfur concentration expressed as sulfur dioxide shall be calculated using the following equation for the period of time this parameter was not measured or recorded:

$$SFE = Max\ SFE - 0.5(Max\ SFE - Avg\ SFE)$$

Where:

SFE	=	Estimated total sulfur concentration, expressed as sulfur dioxide (ppmv)
Max SFE	=	Maximum total sulfur concentration expressed as sulfur dioxide measured and recorded for that flare during the previous 20 quarters preceding the flare event.

Avg SFE = Average value of all total sulfur concentrations measured and recorded for that flare for all sampled flare events during the previous 20 quarters preceding the flare event.

ii) Alternate methods using recorded and verifiable operational parameters, sampled data, and/ or process data, including reference to similar events that have previously occurred, approved by the Executive Officer to be representative of the total sulfur concentration of the vent gas expressed as sulfur dioxide, may be used to determine the total sulfur concentration in lieu of the method specified above.