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 FLARE is a flare that is designed and configured by installation to combust only natural gas, hydrogen gas and/or liquefied petroleum gas, or any other gas(es) with a fixed composition vented from specific equipment which has been 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, 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 repetitive event from the same equipment caused by poor maintenance, or a condition caused by operator error that results in a flare event shall not be deemed an emergency.

(3) EMERGENCY SERVICE FLARE is a flare other than clean service flare that is designed and configured by installation to combust only vent gases as a result of any situation arising from sudden and unforeseeable events beyond the reasonable control of the owner or operator of the gas flare which require immediate corrective action to restore normal and safe operation including emergency process 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.

(4) ESSENTIAL OPERATIONAL NEED is an activity 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 for reasons other than poor maintenance or operator error;

(B) Relief valve leakage due to malfunction;

(C) 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;

(D) Venting of clean service streams to a clean service flare or a general service flare;

(E) Intermittent minor venting from:
   (i) Sight glasses;
   (ii) Compressor bottles;
   (iii) Sampling systems; or
   (iv) Pump or compressor vents; or

(F) An emergency situation in the process operation resulting from the vessel operating pressure rising above pressure relief devices’ set points, or maximum vessel operating temperature set point.
(5) 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. This consists of both ground and elevated flares. When used as a verb means the combustion of vent gases in a flare device.

(6) FLARE EVENT is any intentional or unintentional combustion of vent gas in a flare. The flare event ends when the 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. For a flare event that continues for more than 24 hours, each day of venting of gases shall constitute a flare event.

(7) 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.

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

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

(10) GENERAL SERVICE FLARE is a flare that is not defined in paragraphs (b)(1) or (b)(3) that is designed and configured by installation to combust vent gases as a result of any situation including, but not limited to, relief of excess operating pressures, tank vapor displacement, start-ups, shutdowns, process unit turnarounds and blowdowns, and scheduled and unscheduled maintenance and clean up.

(11) 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.

(12) 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.
(13) 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.

(14) PETROLEUM REFINERY is a facility that processes petroleum, as defined in the Standard Industrial Classification Manual as Industry No. 2911, Petroleum Refining. 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.

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

(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) SAMPLING FLARE EVENT is any flare event for a specific flare exceeding either a flow rate of 330 standard cubic feet per minute continuously for a period greater than 15 minutes, or any other flare event, as requested by the petroleum refinery and approved in writing by the Executive Officer. Sampling flare events that occur within 15 minutes of each other are considered a single event if the facility can demonstrate to the satisfaction of the Executive Officer that the events had a common cause and the release of vent gas originated from the same process unit.

(19) 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.

(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, 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.

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

(1) Effective January 1, 2006:

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

(B) 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)(3).

(C) 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.

(D) Conduct a Specific Cause Analysis for any flare event, excluding planned shutdown, planned startup and turnarounds, with emissions exceeding either:

(i) 100 pounds of VOC;

(ii) 500 pounds of sulfur dioxide;

(iii) 500,000 standard cubic feet of vent gas combusted,

(E) 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.
(2) Effective September 1, 2006, submit the following information to the Executive Officer:

(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.

(3) Effective January 1, 2007, submit to the Executive Officer an evaluation of options to reduce flaring during planned shutdowns, startups and turnarounds, including, but not limited to slower vessel depressurization, storing vent gases.

(4) Effective January 1, 2007, 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. Notwithstanding the effective date above, for the owner or operator of a facility subject to this rule that must install flare gas recovery and treatment system(s) to comply with the requirements of this paragraph, the effective date for a flare directly associated with the proposed flare gas recovery and treatment system shall be January 1, 2009, provided the owner or operator submits a complete application to construct and operate a flare gas recovery and treatment system(s) by July 1, 2006. For a facility installing flare gas treatment and recovery system(s) for more than two flares, the owner or operator may request an extension of the compliance date specified in this paragraph for the flare gas recovery and treatment system serving the additional flares to no later than January 1, 2010. The Executive Officer may grant an extension
Rule 1118 (Cont.)

provided that the owner or operator submits a request in writing to the Executive Officer prior to January 1, 2007, and the facility demonstrates that an extension is necessary due to operational needs.

(5) Effective January 1, 2009, 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, process upset or relief valve leakage. Notwithstanding the effective date above, for the owner or operator of a facility installing flare gas treatment and recovery system(s) for more than two flares to comply with the requirements of paragraph (c)(4), the owner or operator may request an extension of the compliance date specified in this paragraph for the flare gas recovery and treatment system serving the additional flares to no later than January 1, 2010. The Executive Officer may grant an extension provided that the owner or operator submits a request in writing to the Executive Officer prior to January 1, 2007, and the facility demonstrates that an extension is necessary due to operational needs.

(d) Performance Targets

(1) The owner or operator of a petroleum refinery subject to this rule shall minimize flare emissions and meet the following performance targets:

(A) Beginning with calendar year 2006, minimize sulfur dioxide emissions from flares to less than 1.5 tons per million barrels of crude processing capacity, calculated as an average over one calendar year;

(B) Beginning with calendar year 2008, minimize sulfur dioxide emissions from flares to less than 1 ton per million barrels of crude processing capacity, calculated as an average over one calendar year;

(C) Beginning with calendar year 2010, minimize sulfur dioxide emissions from flares to less than 0.7 tons per million barrels of crude processing capacity, calculated as an average over one calendar year;

(D) Beginning with calendar year 2012, minimize sulfur dioxide emissions from flares to less than 0.5 tons per million barrels of
crude processing capacity, calculated as an average over one calendar year.

Compliance with the performance targets above 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 targets of paragraph (d)(1) are 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 targets of paragraph (d)(1) are 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, and

(iv) Notwithstanding the mitigation fee schedule of this subparagraph, the mitigation fee for a petroleum refinery for a calendar year will not exceed $4,000,000.

(e) Flare Minimization Plan
(1) The owner or operator of a petroleum refinery exceeding the performance targets in paragraph (d)(1) shall submit, no later than 90 days from 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 targets in subdivision (d), including the following:

(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) Detailed process flow diagrams of all upstream equipment and process units venting to each flare, identifying the type and location of all control equipment;

(C) Refinery policies and procedures to be implemented and any equipment improvements to minimize flaring and flare emissions and comply with the performance targets of paragraph (d)(1) 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 upset, based on an evaluation of the adequacy of maintenance schedules for equipment, process and control instrumentation.

(D) Any flare gas recovery equipment and treatment system(s) to be installed to comply with the performance targets of paragraph (d)(1).

(2) 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 will be deemed in violation of this rule upon the Executive Officer’s denial of the Flare Minimization Plan.

(3) The owner or operator of a petroleum refinery having an existing approved Flare Minimization Plan shall, no later than 90 days from 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.

(4) 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, as of November 4, 2005, shall:

(A) On or before June 30, 2006, 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)(3) of this rule.

(B) Comply with the most current Flare Monitoring and Recording Plan approved by the Executive Officer and in effect prior to November 4, 2005. The Executive Officer will amend the plan to include Rule 1118 as adopted on February 13, 1998, to become part of the plan and will issue the amended plan within 30 days of November 4, 2005. The amended plan shall remain in effect until the Revised Flare Monitoring and Recording Plan, submitted
pursuant to subparagraph (f)(1)(A) is approved by the Executive Officer.

(C) 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.

(2) 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 on or after February 13, 1998 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)(3) of this rule.

(3) Each Flare Monitoring and Recording Plan or Revised 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 subdivision (b), 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), purge gas system, pilot gas system, ignition system, assist system, water seal, knockout drum and molecular seal.

(E) 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 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, 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 deactuating 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 and 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) 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.

(Q) A request to use the alternative sampling program pursuant to subparagraph (g)(4)(C), if applicable, with a complete description of proposed Quality Assurance/Quality Control procedures to be used in a test program to determine the correlation between the results from the alternative sampling program and the testing and monitoring methods specified in subdivision (j).

(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), in accordance with 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 subparagraph (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**

**Effective until June 30, 2007**

<table>
<thead>
<tr>
<th>TYPE OF FLARE</th>
<th>OPERATING PARAMETER</th>
<th>MONITORING AND RECORDING</th>
</tr>
</thead>
<tbody>
<tr>
<td>Clean Service</td>
<td>Gas Flow¹</td>
<td>Measured and Recorded² Continuously with Flow Meter(s) and/or On/Off Flow Indicator(s)</td>
</tr>
<tr>
<td></td>
<td>Gas Higher Heating Value³</td>
<td>Calculated or Representative Sample for Each Flare Event⁴</td>
</tr>
<tr>
<td></td>
<td>Total Sulfur Concentration⁵</td>
<td>Calculated or Representative Sample for Each Flare Event</td>
</tr>
<tr>
<td>Emergency Service</td>
<td>Gas Flow¹</td>
<td>Measured and Recorded² Continuously with Flow Meter(s) and/or On/Off Flow Indicator(s)</td>
</tr>
<tr>
<td></td>
<td>Gas Higher Heating Value</td>
<td>One Daily Representative Sample for a Flare Event and a Representative Sample for Each Sampling Flare Event⁴; or Continuously Measured and Recorded with a Higher Heating Value Analyzer</td>
</tr>
<tr>
<td></td>
<td>Total Sulfur Concentration⁵</td>
<td>One Daily Representative Sample for a Flare Event and a Representative Sample for Each Sampling Flare Event⁴; or Semi-Continuously Measured and Recorded with a Total Sulfur Analyzer</td>
</tr>
<tr>
<td>General Service</td>
<td>Gas Flow¹</td>
<td>Measured and Recorded² Continuously with Flow Meter(s) with or without on/off flow indicator(s)</td>
</tr>
<tr>
<td></td>
<td>Gas Higher Heating Value³</td>
<td>One Daily Representative Sample for a Flare Event and a Representative Sample for Each Sampling Flare Event⁴; or Continuously Measured and Recorded with a Higher Heating Value Analyzer</td>
</tr>
<tr>
<td>TYPE OF FLARE</td>
<td>OPERATING PARAMETER</td>
<td>MONITORING AND RECORDING</td>
</tr>
<tr>
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</tr>
<tr>
<td>General Service</td>
<td>Total Sulfur Concentration 5</td>
<td>One Daily Representative Sample for a Flare Event and a Representative Sample for Each Sampling Flare Event 4; or Semi-Continuously Measured and Recorded with a Total Sulfur Analyzer</td>
</tr>
</tbody>
</table>

1. Standard Cubic Feet per Minute.
2. All flow meters, flow indicators and recorders shall meet or exceed the minimum specifications listed below upon rule adoption or those in Attachment A by January 1, 2007:
   (i) Velocity Range: 1-250 ft/sec
   (ii) Repeatability: ± 1% of reading over the velocity range
   (iii) Accuracy: ± 5% of reading over the velocity range
   (iv) Installation: Applicable AGA, ANSI, API, or equivalent standard; hot tap capability.
   (v) Flow Rate Determination Applicable AGA, ANSI, API, or equivalent standard.
3. Higher (Gross) Heating Value in British Thermal Units per Standard Cubic Foot.
4. Sample shall be taken within 30 minutes of the start of each flare event. Only one representative sample is required each day for flare events that are not sampling flare events. A representative sample collected for a sampling flare event on that day may be used to satisfy this requirement. Sampling flare events that occur within 15 minutes of each other are considered a single event if the facility can demonstrate to the satisfaction of the Executive Officer that the events had a common cause and the release of vent gas originated from the same process unit. For flare events lasting 15 minutes or less, no representative sample is required and emission shall be calculated according to the procedure in Attachment B Section 1 Note (2). A sample shall not be required if the operator demonstrates vent gas is not routed to a flare based on 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. The requirement for daily representative sample shall be effective January 1, 2006.
5. Total Sulfur as SO₂, ppm.

Effective July 1, 2007

<table>
<thead>
<tr>
<th>TYPE OF FLARE</th>
<th>OPERATING PARAMETER</th>
<th>MONITORING AND RECORDING</th>
</tr>
</thead>
<tbody>
<tr>
<td>Clean Service</td>
<td>Gas Flow 1</td>
<td>Measured and Recorded 2 Continuously with Flow Meter(s) and/or On/Off Flow Indicator(s)</td>
</tr>
<tr>
<td></td>
<td>Gas Higher Heating Value 3</td>
<td>Calculated or Representative Sample for Each Flare Event</td>
</tr>
<tr>
<td></td>
<td>Total Sulfur Concentration 4</td>
<td>Calculated or Representative Sample for Each Flare Event</td>
</tr>
<tr>
<td>TYPE OF FLARE</td>
<td>OPERATING PARAMETER</td>
<td>MONITORING AND RECORDING</td>
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<tr>
<td>-------------------</td>
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</tr>
<tr>
<td>Emergency Service</td>
<td>Gas Flow&lt;sup&gt;1&lt;/sup&gt;</td>
<td>Measured and Recorded&lt;sup&gt;2&lt;/sup&gt; Continuously with Flow Meter(s) and/or On/Off Flow Indicator(s)</td>
</tr>
<tr>
<td></td>
<td>Gas Higher Heating Value&lt;sup&gt;3&lt;/sup&gt;</td>
<td>Continuously Measured and Recorded with a Higher Heating Value Analyzer</td>
</tr>
<tr>
<td></td>
<td>Total Sulfur Concentration&lt;sup&gt;4&lt;/sup&gt;</td>
<td>Semi-Continuously Measured and Recorded with a Total Sulfur Analyzer</td>
</tr>
<tr>
<td>General Service</td>
<td>Gas Flow&lt;sup&gt;1&lt;/sup&gt;</td>
<td>Measured and Recorded&lt;sup&gt;2&lt;/sup&gt; Continuously with Flow Meter(s) with or without on/off flow indicator(s)</td>
</tr>
<tr>
<td></td>
<td>Gas Higher Heating Value&lt;sup&gt;3&lt;/sup&gt;</td>
<td>Continuously Measured and Recorded with a Higher Heating Value Analyzer</td>
</tr>
<tr>
<td></td>
<td>Total Sulfur Concentration&lt;sup&gt;4&lt;/sup&gt;</td>
<td>Semi-Continuously Measured and Recorded with a Total Sulfur Analyzer</td>
</tr>
</tbody>
</table>

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 SO₂, ppm.

(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).
(B) The owner or operator of a flare may comply with the vent gas sampling requirements of paragraph (g)(3) based on alternative criteria for determining a sampling flare event for each specific flare, provided that such alternative criteria are submitted as part of the Flare Monitoring and Recording Plan in subparagraph (f)(3)(P), and are approved in writing by the Executive Officer.

(C) During the interim period, which is after the approval of the Flare Monitoring and Recording Plan or Revised Flare Monitoring and Recording Plan and until in compliance with paragraph (g)(1), an alternative sampling program for sampling flare events for each flare may be used provided the following requirements are met:

(i) A request to use an alternative sampling program has been submitted by the flare owner or operator as part of the Flare Monitoring and Recording Plan pursuant to subparagraph (f)(3)(Q) and approved as equivalent by the Executive Officer. The Executive Officer must make a finding, in the case of an existing facility, that compliance with subparagraph (f)(1)(B) is not feasible.

(ii) The vent gas(es) to each flare shall be sampled and analyzed, if applicable, for total sulfur and higher (gross) heating value in accordance with methods specified in subdivision (j), once a day. If there is a sampling flare event in any day, the sampling and analysis shall also be conducted during such event in addition to the daily sampling requirement.

(iii) In addition to the samples collected and analyzed pursuant to the requirements in clause (g)(4)(C)(ii), the vent gas(es) to each flare shall be sampled and analyzed in accordance with Table 1, as follows:

(I) Once a day during each sampling flare event other than the flare event specified in clause (g)(4)(C)(ii), if such a sampling event occurs during that day.

(II) For all sampling flare events that are the result of any process unit shutdown.

(iv) The vent gas(es) to each flare shall be sampled and analyzed for all other sampling flare events to measure
hydrogen sulfide concentrations in the vent gas using a colorimetric method or other methods as specified in the Flare Monitoring and Recording Plan pursuant to subparagraph (f)(3)(Q) and as approved in writing by the Executive Officer.

(D) After the interim period of monitoring and recording pursuant to subparagraph (g)(4)(C), the owner or operator of a flare may, based on the monitoring data, request a change in the vent gas sampling requirement of paragraph (g)(3) and/or propose an equivalent alternative criteria for determining a sampling flare event for each specific flare, provided that the owner or operator of the flare submits an application for the modification to the Flare Monitoring and Recording Plan and can demonstrate, and obtain written approval of the Executive Officer that an alternative vent gas sampling and/or an alternative criteria for determining a sampling flare event for each specific flare is equivalent to the sampling requirement of paragraph (g)(3) and is adequate to determine the quality of vent gas(es) and to calculate emissions from all such flare events.

(E) After the interim period of monitoring and recording pursuant to subparagraph (g)(4)(C), the Executive Officer may revise any alternative criteria for determining a sampling flare event for each specific flare or any alternative vent gas sampling which have been previously proposed by the owner or operator of a flare and approved by the Executive Officer, if the Executive Officer determines that the alternative(s) is not adequate based on the monitoring data or other information to determine the quality of vent gas(es) and to calculate emissions from all such flare events. The owner or operator of the flare shall use the revised criteria for determining a sampling flare event or vent gas sampling to monitor and record flare events no later than 30 days after written notification by the Executive Officer.

(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) Effective July 1, 2007, if the flare monitoring system is used to measure and record the operating parameters for emergency service flares, as well as 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) Effective July 1, 2006, 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 flame at a rate of no less than one frame per minute.

(8) Effective January 1, 2007, for all emergency and general service flares:

(A) Install each flow meter 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) Install an automated sample collection system at each flare, capable to alert personnel that a sample is being collected following the start of a sampling flare event, unless total sulfur is monitored with a certified analyzer approved by the Executive Officer.

(C) 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.

(h) Recordkeeping Requirements
The owner or operator of a flare shall maintain records in a manner approved by the Executive Officer for all the information required to be monitored and make such records available to the Executive Officer upon request:

(1) For a period of 90 days for the information required under paragraph (g)(7); and

(2) For a period of five (5) years for all the information required under paragraphs (g)(3), (g)(4), (g)(5), (g)(6) and subparagraph (g)(8)(C) as applicable.

(i) Notification and Reporting Requirements
Effective January 1, 2006, 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 by telephone within one hour 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, and

(3) Submit a Specific Cause Analysis as required by subparagraph (c)(1)(D) to the Executive Officer within 30 days, identifying the cause and duration of the unplanned flare event, and any mitigation and corrective actions
taken. The owner or operator may request the Executive Officer to grant an extension of up to 30 days to submit the Specific Cause Analysis.

(4) Notify the Executive Officer 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.

(5) 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 paragraph (g)(3), (g)(4), (g)(5), (g)(6) and subparagraph (g)(8)(C) of this rule.

(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 subparagraphs (c)(1)(D) and (c)(1)(E) 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 subparagraph (c)(1)(C). 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.
Alternative test methods may be used if it is determined to be equivalent
and approved in writing by the Executive Officer, and, if applicable by the
California Air Resources Board, and the U.S. Environmental Protection
Agency.

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

(i) ASTM Method D 2382-88, ASTM Method D 3588-91 or
ASTM Method D 4891-89, and

(ii) Effective July 1, 2007, 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 5504-01, and

(ii) Effective July 1, 2007, with a total sulfur analyzer that
meets or exceeds the specifications in Attachment A.

(C) The 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) Until the continuous and semi-continuous analyzers are certified by the
Executive Officer and operational, analyses for higher (gross) heating
value and total sulfur concentration shall be:

(A) Conducted by a District approved lab; or
(B) Conducted by the owner or operator of a gas flare if the District has provided prior written approval of QA/QC and standard operating procedures. All analytical reports shall be signed by the facility official responsible for analytical equipment to certify the accuracy of the reports.

(3) Visible emissions pursuant to subparagraph (c)(1)(B) shall be determined by US EPA Method 22, 40 CFR Part 60 Appendix A.

(4) Notwithstanding paragraph (j)(1) and (j)(2), 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) Exemptions

(1) Notwithstanding a flare monitoring system, consisting of a flow meter, higher heating value analyzer and total sulfur analyzer that is in operation, sampling and analyses of representative samples for higher 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 from flaring 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 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.
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°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 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. See rule 218 (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(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. See rule 218(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(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, 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:

<table>
<thead>
<tr>
<th>Air Pollutant</th>
<th>Equation</th>
<th>Emission Factor</th>
</tr>
</thead>
<tbody>
<tr>
<td>ROG</td>
<td>E = V \times HHV x EF</td>
<td>0.063 lb/mmBTU</td>
</tr>
<tr>
<td>NOx</td>
<td>E = V \times HHV x EF</td>
<td>0.068 lb/mmBTU</td>
</tr>
<tr>
<td>CO</td>
<td>E = V \times HHV x EF</td>
<td>0.37 lb/mmBTU</td>
</tr>
<tr>
<td>PM10</td>
<td>E = V \times EF</td>
<td>21 lb/mmSCF</td>
</tr>
<tr>
<td>SOx</td>
<td>E = V \times Cs \times 0.1662</td>
<td>Note (1)</td>
</tr>
</tbody>
</table>

Where:

- $E =$ Calculate vent gas emissions (lbs)
- $V =$ Volume flow of vent gas, as measured in million standard cubic foot at 14.7 psia and 68° Fahrenheit
- HHV = Higher Heating Value, as measured in British Thermal Unit 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) 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.

Note (2) For a flare event where a representative sample or other sampling method is not required pursuant to Table 1 of this rule, use HHV and/or Cs from any representative sample of a flare event on the same day. If no representative sample is taken that day, use HHV and/or Cs from the last representative sample taken prior to the flare event.

<table>
<thead>
<tr>
<th>Air Pollutant</th>
<th>Equation</th>
<th>Emission Factor (lb/mmSCF)</th>
</tr>
</thead>
<tbody>
<tr>
<td>ROG</td>
<td>E = V \times EF</td>
<td>7</td>
</tr>
<tr>
<td>NOx</td>
<td>E = V \times EF</td>
<td>130</td>
</tr>
<tr>
<td>CO</td>
<td>E = V \times EF</td>
<td>35</td>
</tr>
<tr>
<td>PM10</td>
<td>E = V \times EF</td>
<td>7.5</td>
</tr>
<tr>
<td>SOx</td>
<td>E = V \times EF</td>
<td>0.83</td>
</tr>
</tbody>
</table>
Propane and Butane

<table>
<thead>
<tr>
<th>Air Pollutant</th>
<th>Equation</th>
<th>Emission Factor (lb/mmBTU)</th>
</tr>
</thead>
<tbody>
<tr>
<td>ROG</td>
<td>$E = V \times 3500 \times EF$</td>
<td>0.003</td>
</tr>
<tr>
<td>NOx</td>
<td>$E = V \times 3500 \times EF$</td>
<td>0.13</td>
</tr>
<tr>
<td>CO</td>
<td>$E = V \times 3500 \times EF$</td>
<td>0.032</td>
</tr>
<tr>
<td>PM10</td>
<td>$E = V \times 3500 \times EF$</td>
<td>0.0014</td>
</tr>
<tr>
<td>SOx</td>
<td>$E = V \times 3500 \times EF$</td>
<td>0.047</td>
</tr>
</tbody>
</table>

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.

d) 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.

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:

\[
FR = \text{Max. FR} - 0.5(\text{Max. FR} - \text{Avg. FR})
\]

Where:

- \( FR \) = Estimated Flow Rate (standard cubic feet per minute)
- \( \text{Max FR} \) = 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.
- \( \text{Avg FR} \) = 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:

\[ HHV = \text{Max HHV} - 0.5(\text{Max HHV} - \text{Avg HHV}) \]

Where:

\begin{align*}
\text{HHV} & = \text{Estimated higher heating value (Btu/scf)} \\
\text{Max HHV} & = \text{Maximum HHV measured and recorded for that flare during the previous 20 quarters preceding the flare event.} \\
\text{Avg HHV} & = \text{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.}
\end{align*}

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 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:

\[ SFE = \text{Max SFE} - 0.5(\text{Max SFE} - \text{Avg SFE}) \]

Where:

\begin{align*}
\text{SFE} & = \text{Estimated total sulfur concentration, expressed as sulfur dioxide (ppmv)} \\
\text{Max SFE} & = \text{Maximum total sulfur concentration expressed as sulfur dioxide measured and recorded for that flare during the previous 20 quarters preceding the flare event.} \\
\text{Avg SFE} & = \text{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.}
\end{align*}

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 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.
FINAL STAFF REPORT FOR

PROPOSED AMENDED RULE 1118 — CONTROL OF EMISSIONS FROM REFINERY FLARES

Dated: October 2005

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TABLE OF CONTENTS

EXECUTIVE SUMMARY  ---------------------------------------------------------------------------------------------------------- ES-1

CHAPTER I – BACKGROUND --------------------------------------------------------------------------------------------------------- I-1

A. RULE HISTORY  ------------------------------------------------------------------------------------------------------------- 1-1
B. OTHER CALIFORNIA DISTRICTS FLARE RULES  ----------------------------------------------------------------------------------- I-2
C. US EPA REGULATIONS  ---------------------------------------------------------------------------------------------------------- I-3
D. EQUIPMENT AND OPERATION  ----------------------------------------------------------------------------------------------------- I-4
E. APPLICABLE RULES REVIEW  ----------------------------------------------------------------------------------------------------- I-5
F. AFFECTED FACILITIES  ---------------------------------------------------------------------------------------------------------- I-6

CHAPTER II – CONTROL TECHNOLOGY  ------------------------------------------------------------------------------------------------ II-1

A. CONTROL OPTIONS  ------------------------------------------------------------------------------------------------------------- II-1
B. FLARE MINIMIZATION PLANS  --------------------------------------------------------------------------------------------------- II-1
C. FLARE GAS RECOVERY SYSTEMS  --------------------------------------------------------------------------------------------- II-2

CHAPTER III – PROPOSED RULE AMENDMENTS  --------------------------------------------------------------------------------------- III-1

A. DEFINITIONS  --------------------------------------------------------------------------------------------------------------- III-1
B. REQUIREMENTS  --------------------------------------------------------------------------------------------------------------- III-3
C. PERFORMANCE TARGETS  -------------------------------------------------------------------------------------------------------- III-4
D. FLARE MINIMIZATION PLAN REQUIREMENTS  -------------------------------------------------------------------------------------- III-7
E. FLARE MONITORING AND RECORDING PLANS  --------------------------------------------------------------------------------------- III-28
F. OPERATION MONITORING AND RECORDING  ------------------------------------------------------------------------------------------ III-8
G. RECORDKEEPING REQUIREMENTS  ----------------------------------------------------------------------------------------------- III-910
H. NOTIFICATION AND REPORTING  ----------------------------------------------------------------------------------------------- III-910
I. TEST METHODS  --------------------------------------------------------------------------------------------------------------- III-10
J. EXEMPTIONS  --------------------------------------------------------------------------------------------------------------- III-1011
CHAPTER IV – EMISSION INVENTORY

A. CONTRIBUTING SOURCES

B. EMISSION INVENTORY

CHAPTER V – EMISSION REDUCTIONS

CHAPTER VI – COST-AND COST EFFECTIVENESS

A. COSTS

B. COST-EFFECTIVENESS

CHAPTER VII – COMPARATIVE ANALYSIS

CHAPTER VIII – DRAFT FINDINGS

CHAPTER IX – COMMENTS AND RESPONSES

APPENDIX A – REFERENCES

APPENDIX B – CALIFORNIA AIR RESOURCES BOARD RESOLUTION 86-60
EXECUTIVE SUMMARY
Rule 1118 – Emissions from Refinery Flares was originally adopted by the South Coast Air Quality Management District (AQMD) on February 13, 1998, with the purpose of monitoring, recording and reporting data on petroleum refinery flaring and related operations. This represented Step I of Control Measure CMB-07 of the 1997 Air Quality Management Plan (AQMP) that targets emission reductions from refinery flares, also found in the 2003 AQMP. Pursuant to the AQMD Board’s direction upon the adoption of the rule, staff analyzed the monitoring data submitted by refineries in the time period from October 1, 1999 through December 31, 2003 and compiled the “Evaluation Report on Emissions from Flaring Operations at Refineries”.

Staff presented the report at the September 3, 2004 AQMD Board Meeting and concluded that emissions from refinery flares were significant enough to warrant the implementation of controls. The report suggests possible ways of reducing emissions through the prevention of flaring of excess fuel gas, the elimination of leaks from pressure relief devices and the reduction of emissions during routine flaring. These objectives can be achieved by installing flare gas recovery systems and gas treating systems, expanding current capacities of flare gas recovery and treatment systems already in place, and conducting surveys to detect leaking pressure relief devices. The report also recommended improvements in the measurement of flare vent gas flows and the installation of continuous monitoring systems to measure the total sulfur gas concentration and the higher heating value of the flared gas, as well as the standardization of methodologies for flow and emissions calculations and for missing data substitution. Following the report presentation, the AQMD Board directed staff to amend Rule 1118 – Emissions from Refinery Flares, and implement Step II of Control Measure CMB-07. Step II of the control measure aims to reduce emissions of criteria pollutants from refinery flares by identifying and requiring the most feasible and cost-effective control options available.

The air quality objective for the Proposed Amended Rule (PAR) 1118 is to help AQMD attain state and federal air quality standards by minimizing emissions of criteria air contaminants and their precursors from flaring activities at petroleum refineries. The proposed amendment would eliminate the flaring of vent gases except for those resulting from emergencies, shutdowns and startups, turnarounds and essential operational needs; establish operational requirements of diagnostic practices to minimize flaring.

The proposed amendment establishes refinery specific performance targets for flare-related total sulfur emissions, calculated as sulfur dioxide, at 1.5 tons per million barrels of crude processed capacity in calendar year 2006, 1 ton per million barrels of crude processed capacity in calendar year 2008, 0.7 tons per million barrels of crude processed capacity in calendar year 2010, and 0.5 tons per million barrels of crude processed capacity in calendar year 2012, respectively, based on the 2004 industry-wide throughput processing capacity. During the rule development process, industry identified an inequity of using crude throughput versus crude processing capacity to establish annual SO2 performance targets. In any one year, any refinery could be conducting a shutdown or turnaround of a major crude processing unit, which could reduce crude throughput for that baseline year reflecting an artificially low baseline throughput for that refinery. Whereas crude processing capacity more accurately allocates refinery emissions based on normal refinery operations. Local refineries are operating at near capacity; therefore, the difference in emissions impact and reductions based on throughput or capacity are minimal. Excess flare related total sulfur emissions would be subject to mitigation fees of $25,000, $50,000 or $100,000 per ton, depending on whether excess emissions are no more than ten percent, greater than twenty percent but less than twenty percent,
or more than twenty percent, respectively, of the annual performance targets. Excess emissions would also trigger the submittal of a flare minimization plan by the refinery and a possible issuance of a Notice of Sulfur Dioxide Exceedance by the Executive Officer. Emissions resulting from external power curtailment, natural disasters or acts of war or terrorism will be exempt from being counted towards these limits.

The proposed amendment, in keeping with the recommendations from the “Evaluation Report on Emissions from Flaring Operations at Refineries”, will also enhance monitoring requirements to improve data reporting accuracy, primarily requiring the use of higher heating value analyzers and also total sulfur analyzers pending the result of a pilot test feasibility study taking place at one of the refineries. Until the analyzers are installed, but no later than July 1, 2007, the sampling frequency of flare events would be increased to daily from weekly. In addition, the rule will require the flare gas flow meters to be installed in a representative location or be upgraded with totalizing capability such that only an accurate flow to the flare is registered. The amended rule will also establish uniform missing data procedures and calculations for reporting emissions during monitors’ downtime periods.

The amended rule will set new notification requirements for flaring events, as well as reporting, which will require quarterly reports to be submitted in an electronic format certified by the facility official and approved by the Executive Officer. Each petroleum refinery will submit a detailed technical description of the flare system, including an audit of vent gas recovery capacity, a summary of the flaring emissions reductions achieved to date and future planned flare emission reductions.

The emissions reductions associated with proposed amendments are estimated to be 1.18 tons per day of SO\(_2\) and 1.44 tons per day overall for all criteria pollutants, excluding carbon monoxide, from the emissions baseline average (2002-2004) to 2012. The cost-effectiveness is estimated to be between $3,922,524 and $6,926,620 per ton of SO\(_2\) reduced. When considering additional reductions in NO\(_x\), VOC and PM10, the cost effectiveness ranges between $3,442,527 and $5,675,063 per ton of pollutant reduced.

The proposed amended Rule 1118 is considered a “project” as defined by the California Environmental Quality Act (CEQA), and the AQMD is the designated lead agency. Pursuant to CEQA and AQMD Rule 110, the AQMD prepared an environmental assessment (EA) evaluating potential adverse significant impacts associated with implementing the proposed amended rule. The EA concluded that implementing PAR 1118 would have no significant impacts on the environment. An environmental impact is defined as an impact to the physical conditions that exist within the area which would be affected by the proposed project.
CHAPTER I

BACKGROUND
A. **RULE HISTORY**

The concept of reducing emissions from petroleum refinery operations was originally formalized in the 1982 Air Quality Management Plan (AQMP) as Measure A15. Measure A15 proposed increasing the use of blowdown and vapor recovery systems to reduce emissions from flares. Consideration of adoption in 1985 was postponed to provide additional time to collect background information regarding flaring operations and alternative control options. Measure A15 has been carried over through subsequent AQMPs and in the 2003 AQMP takes the form of Control Measure CMB-07.

In 1984, the Citizens for a Better Environment (CBE) petitioned the California Air Resources Board (CARB) to make a determination of the technological feasibility, availability and economic reasonableness of continuous emission monitors for refinery flares. CARB granted the CBE request and contracted a study with an engineering firm to evaluate the feasibility of continuously monitoring flaring operations at petroleum refineries. The study found that no refinery in California accurately monitored flow rates to its flares. Several types of flow meters had been installed on refinery flares, but the instrumentation could only provide relative flow information because the gas density varies and gas constituent data is necessary to calculate flow accurately. The study concluded that continuous monitoring of flare gas flow rates, gas composition and remote monitoring of flare plumes were practicable but would require substantial further development before they could be considered ready to use for accurate and precise measurements on flares at a reasonable cost.

Despite concluding that the aforementioned devices still required substantial development, the study found that devices which constantly monitored the on/off status of refinery flares were not only practicable, but were also ready to use at a relatively inexpensive cost. In 1986, CARB determined that monitoring devices were technologically feasible, available and economically reasonable for limited applications to identify and record continuously the on/off status of refinery flares in order to better quantify flare emissions. This finding was formalized and adopted by CARB as Resolution No. 86-60. CARB also encouraged local air pollution control districts to adopt rules requiring refineries to install on/off status monitors and collect flare gas composition data so that a suggested control measure for the control of emissions from refinery flares could be developed.

In 1987 through 1988, refineries in the South Coast Air Basin participated in a flare study resulting from CARB Resolution No. 86-60. The results of this study met with limited success. Staff’s review of the available data has determined that the results of the study are insufficient to quantify the emissions from petroleum refineries, especially in light of the recent refinery modifications to produce clean fuels. In addition, the previous monitoring equipment used in this study was found to be maintenance intensive and is no longer used by the refineries.

Since 1988, staff has tracked the development of available technology that could accurately monitor gas flare parameters which would result in sufficient data to quantify emissions. Recent advances in technology have resulted in devices that can now accurately monitor gas flare parameters. Staff has found that these monitoring devices are currently being used in various industries that use gas flares with favorable results.

In 1993 and 1994, staff required two refineries to conduct flare system studies as a result of frequent complaints of odor from emissions associated with their gas flaring operations. Recommendations based on these studies were implemented and resulted in a significant reduction in violations of Rule 402 – Public Nuisance. These studies and subsequent
implementation of recommendations showed that each refinery flare system is complex and unique, but that opportunities do exist to reduce nuisance problems associated with refinery flare systems.

On February 13, 1998, the AQMD Board adopted Rule 1118 with the purpose of monitoring, recording and reporting data on refinery and related flaring operations. Upon rule adoption, the AQMD Board passed a resolution directing staff to a) collect and analyze the data submitted by subject refineries to determine if flare emissions are significant, and b) recommend whether further controls are needed.

After evaluating the data submitted to the AQMD from October 1, 1999 through December 31, 2003, staff compiled the “Evaluation Report on Emissions from Flaring Operations at Refineries”, which was presented to the AQMD Board on September 3, 2004. The report recommended amending Rule 1118, concluding that, although refineries had made important progress in reducing emissions since Rule 1118 was originally adopted, flare emissions, especially oxides of sulfur (SOx), were still significant enough to warrant further controls. The report suggest various ways to reduce flare emissions, such as the elimination of leaks from pressure relief devices, the installation of flare gas recovery systems and gas treating systems. In addition to focus on minimization of flare emissions, the report emphasized the potential of the amendment to improve the monitoring, reporting and emission calculation methodology in order to increase the accuracy of the data collected.

B. OTHER CALIFORNIA DISTRICTS FLARE RULES

Several other air pollution control districts in California also have flare rules. The Bay Area Air Quality Management District’s (BAAQMD) Rule 12-11, adopted in June 2003, is comparable to AQMD’s current Rule 1118. Rule 12-11 – Flare Monitoring at Petroleum refineries applies to refineries in the San Francisco area. The rule requires the monitoring and recording of the vent gas and the composition as well as continuously recording digital video images of the flare tip for each flare. Refineries are required to submit monthly reports in electronic format, containing daily flows and gas composition and corresponding calculated emissions of methane, non-methane hydrocarbons and sulfur compounds resulting from combustion, as well as the archived video pictures of the flares. A complementary rule, Rule 12-12 which seeks to minimize flare emissions through the use of Flare Minimization Plans was adopted in June 2005, and is similar in some respects to PAR 1118.

The Santa Barbara Air Pollution Control District (SBAPCD) also regulates flares based upon its own Rule 359 - Flares and Thermal Oxidizers, adopted on June 28, 1994. This rule applies to oil and gas production, petroleum refineries and related sources, natural gas services and transportation sources and wholesale trade in petroleum/petroleum products that operate flares or thermal oxidizers. Rule 359 specifies sulfur content limits, technology-based standards for flares and thermal oxidizers, and emission standards for oxides of nitrogen (NOx) and reactive organic compounds (ROC) and operational limits. The rule also incorporates a Flare Minimization Plan, monitoring, recordkeeping, reporting and source test requirements for ground flares. However, a review of the staff report for Rule 359 indicates that there are no petroleum refinery operations in Santa Barbara similar to the petroleum refinery operations in the South Coast Air Basin and that Rule 359 applies to non-refinery petroleum operations such as oil and gas exploration and bulk loading terminals.
Ventura County Air Pollution Control District (VCAPCD) Rule 54 - Sulfur Compounds is similar to the SBAPCD Rule 359. While Rule 54 does apply to flares, as in the case with the SBAPCD rule, Rule 54 also applies to non-refinery petroleum operations and AQMD staff is not aware of any petroleum refinery operations in the jurisdiction of VCAPCD.

C. U.S. EPA REGULATIONS (EPA)

The EPA New Source Performance Standards (NSPS), under 40CFR 60.18 – General Control Device Requirements, contains provisions for flares that control vent gases from storage tanks built after July 23, 1984, subject to 40CFR 60 Subpart Kb and from piping components that were installed after January 4, 1983, subject to Subpart GGG. The federal regulation requires flares to operate without visible emissions, to maintain a pilot flame present at all times the flare is in operation and observe certain limits for the net heating value and exit velocity of the gases being combusted. The regulation also requires monitoring of the flares to ensure that they are operated in compliance with these requirements.

Another NSPS regulation, 40CFR 60 Subpart J – Standards of Performance for Petroleum Refineries, covers operation of combustion devices such as flares, that were built or modified after June 11, 1973 under 40CFR 60.104(a). This regulation limits the concentration of the hydrogen sulfide (H$_2$S) in the vent gases routed to flares to 160 ppm, averaged over three hours. However, vent gases that are combusted due to startup, shutdown, process upset or relief valve leakage are exempt from this requirement.

In 1998, EPA launched a program called “The Petroleum Refinery Initiative” consisting of a series of investigations at refineries under a multi-faceted compliance approach. One of the refinery activities targeted by the investigation was excessive flaring of acid gas (gas with high H$_2$S content generated during the oil refining process and from the sour water stripper) that results in large amounts of sulfur dioxide being released into the atmosphere. Also investigated was excessive hydrocarbon flaring. EPA’s position, as stated in the Enforcement Alert newsletter of October 2000, is that routine or non-emergency flaring does not constitute good air pollution practice and may be a violation of the Clean Air Act. In the newsletter, EPA states that refineries should have adequate capacity to recover and treat sour gases routinely generated in their process without resorting to flaring. Good air pollution practices also include investigating the root cause of a flaring incident and taking corrective actions to prevent recurrence in the future. In the newsletter, EPA states that a properly designed, operated and maintained flare gas recovery system is one way to minimize or avoid flaring.

In an effort to reduce excessive flaring of acid gas and emissions of SOx and NOx, EPA, to date, has entered into 15 global settlements with petroleum refiners representing more than 65% of domestic refinery capacity. The settlements now cover 76 refineries and conferences are currently ongoing with 11 more petroleum refiners who represent an additional 24 refineries. Refineries effected by the global settlements are subject to a consent degree requiring them to prepare and submit plans to minimize hydrocarbon flaring, conduct root cause analyses of flaring events and implement control options such as installing flare gas recovery systems, rerouting hydrocarbon streams away from flares or making hydrocarbon flares compliant with the provisions of 40CFR 60.104(a). By stipulating to consent decrees with EPA, the refineries agreed to undertake certain remediation and mitigation actions, pay fines and provide affirmative relief by completing environmentally beneficial projects. These aforementioned requirements of
the consent decrees are, in part, the concepts on which the proposed amendment to Rule 1118 is based.

Four refineries within the AQMD’s jurisdiction have entered consent decrees with EPA: Equilon Enterprises, BP West Coast Products, Chevron Products Company and Conoco Phillips. As a result of the settlements, these companies pledged to reduce SOx and other air contaminants emissions to the environment by minimizing acid gas and hydrocarbon flaring and by agreeing to subject their flares to the requirements of 40CFR 60.104 for combustion devices.

D. EQUIPMENT AND OPERATION

Flares are combustion devices used extensively in the petroleum industry to burn and dispose of excess combustible gases that are generated as part of the production processes or during a process upset. Flares are also used as safety devices to reduce the potential for fires and explosions due to unburned gaseous hydrocarbon releases. Blowdown systems are designed and installed at petroleum refineries to provide for safe containment or safe release of liquids and gases that must be disposed of in the refining process. Such systems generally consist of a series of venting manifolds which lead from the process equipment to a blowdown recovery system (i.e., storage tank, wastewater system, compressor) and flares.

Flares can be elevated like a stack where the combustion, or burn-off, takes place at the tip of the flare and the flames are visible from a distance. They can also be of the ground-flare type where the burners are concentrically located near the ground level in a shrouded, refractory lined enclosure. Both types of flares are capable of destruction of hydrocarbons and other combustible gases. However, as with any type of combustion equipment, they generate air pollutants such as NOx, SOx, carbon monoxide (CO), and particulate matter (PM), in addition to the release of reactive organic gases (ROG) which have not been completely combusted. Also, similar to any other combustion device, flares have the potential to generate toxic emissions depending on the type of gases burned and operating parameters.

Flares have a design capacity, usually expressed in pounds per hour, which represents the maximum design flow of a specific composition, temperature and pressure of vent gas that can be combusted in a particular flare. Due to federal and local regulations, most flares are designed for smokeless operation over a specified flow range, which is achieved by injecting steam or air at the flare tip to increase turbulence and allow ambient air to better mix with the hydrocarbons. The federal requirement allows refinery flare operators to operate a flare with visible emissions for up to five minutes in any two consecutive hour time period. The smokeless capacity of a flare is defined as the maximum flow to a flare that can be burned without smoke and is also expressed in pounds per hour of a specific gas composition, temperature and pressure. Typically, flares are operating in a smokeless manner in a range up to 20 percent of their maximum design flow; at higher flows the size of the pipe that would be required to provide adequate steam injection at the flare tip becomes a design challenge. Another factor contributing to visible emissions is the nature of the hydrocarbons being combusted. Paraffins have the least tendency to smoke, whereas unsaturated and aromatic hydrocarbons have a higher tendency to smoke.

A flare must have the pilot burners on at all times to ensure ignition of the vent gas generated in the process system it serves whenever it is in operation. A stream of combustible gas, called purge gas, is continuously flowing into the flare to prevent air from entering the flare header.
which can create an unsafe explosive mixture of air and hydrocarbons. Depending on the flare design and size, the amount of purge gas needed to keep the flare safe varies considerably. Although the quantities are relatively small, the burning of pilot and purge gases represent a continuous source of emissions.

In a refinery setting, a gas flare may be installed for only one process area or it can be used to serve a number of process units for a wide variety of purposes ranging from controlling a small stream of leaks or vent gas from a piece of equipment to the disposal of large quantities of gases during an emergency. Therefore, depending on how a flare is designed and used, in Rule 1118 flares are classified into three distinctive categories: clean service, emergency service, and general service.

A clean service flare is used to only burn natural gas, hydrogen, liquefied petroleum gas, or other gases with a fixed composition vented from specific equipment. These gases contain little or no sulfur, and the quality (i.e., heat content and sulfur content) of the gas is usually predictable regardless of the flaring situations. In the basin, there are four clean flares, which are associated with three liquefied propane and butane storage areas and a hydrogen generating plant each.

An emergency service flare is a flare that receives vent gas only during emergencies. The quality and volume of the vent gases vary depending on the source and duration of the emergency release. Nevertheless, an emergency flare is usually in a standby mode and does not create emissions except for those associated with pilot and purge gases, and during actual emergencies.

The most common and complicated flare configuration is the general service flare. In addition to the services described above, flares in a refinery are also used to dispose of gases from routine or non-routine operations including purged gas streams, non-emergency releases of excess pressures, venting of storage tanks or wastewater sumps and equipment leaks, startups and shutdowns, turnaround activities, etc.

**E. APPLICABLE RULES REVIEW**

In addition to Rule 1118, flares are also subject to general AQMD prohibitory rules, such as Rule 401 – Visible Emissions, Rule 402 – Public Nuisance and Rule 431.1 – Sulfur Content of Gaseous Fuels. Flares built after June 11, 1973, are subject to 40CFR 60 Subpart J - New Source Performance Standards (NSPS); flares may also be subject to 40CFR 60.18 – General Control Device Requirements if either vent gases from storage tanks subject to 40CFR 60 Subpart Kb or from components subject to 40CFR 60 Subpart GGG are routed to them.

In order to maintain a smokeless operation, flares at refineries are equipped with steam jets (steam assisted) to provide good mixing of the flare gas with air. Within the smokeless range of operation of a flare, if not enough steam is used during a flaring event, smoking may occur due to pockets of incomplete combustion that are formed in the combustion zone. Rule 401 prohibits visible emissions in excess of Ringelmann 1 or 20 percent opacity for periods exceeding more than three aggregate minutes within any hour. 40CFR 60.18 requires flares to have no visible emissions except for periods of time up to five minutes during two consecutive hours. The two standards are not identical, since they use different methods to determine visible emissions: Rule 401 uses USEPA Reference Method 9 and 40CFR 60.18 uses USEPA Reference Method 22.
If combustion is incomplete, as denoted by visible emissions, odorous materials may be emitted, affecting the area downwind of the flare and potentially resulting in a public nuisance. Odors could also be emitted if the heat content of the flared gas is very low resulting in the flame temperature not being hot enough to ensure complete destruction of odorous materials. The flare operator should supplement combustion with high BTU content gas to prevent this problem. A steam- or air-assisted flare should not be used for disposal of gases with less than 300 BTU/scf.

Although flares operate within refineries subject to Regulation XX - RECLAIM, they are not included in this program and their emissions do not count towards refineries’ RECLAIM SOx and NOx allocations. The total sulfur content of the flare pilot gas and the purge gas, which maintain the flare operating continuously, is limited to a concentration of 40 ppm calculated as H$_2$S, averaged over a four hour period per Rule 431.1 – Sulfur Content of Gaseous Fuels. Most of the flares in the basin use natural gas for purge and pilots in order to comply with this requirement. The total sulfur content of the vent gas routed to a flare due to an emergency is exempt from the rule requirements. The federal regulation, 40CFR 60 Subpart J, has a limit of 160 ppm H$_2$S, averaged over a rolling three hour period, for purge and pilot gas combusted in a flare, whereas emergency vent gases and relief valve leakage are exempt from this requirement.

F. AFFECTED FACILITIES

The types of refinery operations subject to this rule are: petroleum refineries, sulfur recovery plants that recover sulfur compounds from acid gases and sour water generated by petroleum refineries, and hydrogen production plants that produce hydrogen from refinery gas and supply it for petroleum refinery operations. Presently, in the AQMD, there are seven operating petroleum refineries, one sulfur recovery plant and one hydrogen production plant, with a total of 10 distinct physical locations. The following facilities operate 27 flares subject to Rule 1118:

- Air Products (Hydrogen Production Plant)
- BP West Coast Products (Refinery)
- Chevron Products Company (Refinery)
- ConocoPhillips Company (Refinery – Carson Plant)
- ConocoPhillips Company (Refinery – Wilmington Plant)
- Equilon Enterprises, LLC, Shell Oil Products US (Los Angeles Refinery)
- Equilon Enterprises, LLC, Shell Oil Products US (Sulfur Recovery Plant)
- ExxonMobil Oil Corporation (Refinery)
- Paramount Petroleum Corporation (Refinery)
- Ultramar Inc. (Refinery)

Table I-1 shows the subject facilities and an inventory of their flares. Since ConocoPhillips and Equilon Shell Oil submit one quarterly Rule 1118 report for both their facilities (Carson
Plant/Wilmington Plant and L.A. Plant/SRU, respectively) the table shows eight reporting facilities.

<table>
<thead>
<tr>
<th>Reporting Facility</th>
<th>Number of Flares</th>
<th>Type of flare</th>
<th>Clean</th>
<th>Emergency/General Service</th>
</tr>
</thead>
<tbody>
<tr>
<td>A</td>
<td>4</td>
<td>Elevated</td>
<td>1</td>
<td>3</td>
</tr>
<tr>
<td>B</td>
<td>1</td>
<td>Ground Flare</td>
<td>1</td>
<td></td>
</tr>
<tr>
<td>C</td>
<td>2</td>
<td>Elevated</td>
<td></td>
<td>2</td>
</tr>
<tr>
<td>D</td>
<td>2</td>
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</tr>
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<td>5</td>
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<td>5</td>
</tr>
<tr>
<td>F</td>
<td>1</td>
<td>Elevated</td>
<td></td>
<td>1</td>
</tr>
<tr>
<td>G</td>
<td>6</td>
<td>Elevated</td>
<td></td>
<td>6</td>
</tr>
<tr>
<td>H</td>
<td>6</td>
<td>Elevated</td>
<td>1</td>
<td>5</td>
</tr>
</tbody>
</table>

8 Facilities 27 Flares

<table>
<thead>
<tr>
<th>Type of Service</th>
</tr>
</thead>
<tbody>
<tr>
<td>Clean</td>
</tr>
<tr>
<td>4</td>
</tr>
</tbody>
</table>
CHAPTER II

CONTROL TECHNOLOGY
A. **CONTROL OPTIONS**

At petroleum refineries, flares have historically been used to dispose of combustible gases resulting from emergency relief, overpressure, process upsets, startups, shutdowns and other operational and safety reasons to prevent direct release of toxic and/or odorous substances to the atmosphere. In recent years, U.S. Occupational Safety and Health Administration (OSHA) and U.S. EPA have become more concerned with refinery operation, resulting in tighter regulations on safety and emissions control and enforcement actions such as Consent Decrees, as shown before. Furthermore, smoke, noise, glare and odors sometimes associated with refinery operations may, and at times have impacted the surrounding communities, leading to an increase in the involvement of community and environmental groups in the regulatory process of controlling refinery flares.

There are two alternatives to control flare emissions: post-combustion and pre-combustion controls. Possible post-combustion controls could be selective catalytic reduction (SCR) units, Lo-NOx burners, scrubbers and bag houses. While post-combustion control technology exists, the unpredictability of the flare operation and the fact that combustion takes place at the tip of an flare 150 to 200 feet above the ground make such control devices impractical for elevated flares.

Controlling flue gases would be very costly under these circumstances and results would not be guaranteed. Therefore, the best way to control and minimize flare emissions is through the use of pre-combustion control, which prevents the formation and reduces the amount of vent gases routed to refinery flares, or recover the vent gases prior to combustion at the flare.

B. **FLARE MINIMIZATION PLANS**

Refineries can obtain meaningful results in their effort to minimize the volume of vent gases routed to the flare by setting up and implementing flare minimization plans. It is possible to achieve significant reductions in the volume of vent gas generated by process units at refineries. Listed below are several possible alternatives of minimizing flare emissions that could be incorporated in flare minimization plans:

- **Better engineering and equipment design**
  A reevaluation of existing process flow and equipment allowing changes in operating parameters such as temperature and pressure settings may result in reduced volumes of vent gas being generated.

- **Diverting or eliminating streams vented to the flares**
  Certain streams that routinely are directed to the flare may be rerouted and either treated for use as fuel gas or recycled back in the process.

- **Installation of redundant equipment to increase reliability**
  By installing redundant equipment, in case of a breakdown, the spare can be put on line, thus avoiding a process upset that results in gas being routed to the flare.

- **Installation of flow monitors for vent gas generated at each process unit**
  Installation of flow monitors on process units flare headers is a useful tool that allows the operator to quickly identify the origin of increased flare flows and take immediate corrective actions, potentially avoiding a flare event.
- Periodic monitoring maintenance programs of pressure relief valves that identify leaks to the blowdown system, such as acoustic or thermal surveys

Pressure relief devices may develop leaks in time, due to the corrosive nature of the process, due to chattering or improper reseating. Given the extended periods of time between turnarounds, leaks may result in significant emissions, even at small rates. By conducting acoustical or thermal surveys of relief devices connected to the flare, the operators can identify and, with detection equipment currently available, even quantify the amount of leak-through gas that escapes to the flare. Upon identification of leaking relief devices, the operator can prioritize their maintenance and repair in order to reduce flare emissions. This program is especially valuable for those flares that are not equipped with flare gas recovery because these leaks end up being combusted in the flare for extended periods of time until the next scheduled turnaround.

- Conducting Specific Cause Analysis of significant flaring incidents

This investigative procedure is used to identify the cause of significant flaring events and whether any equipment and/or operational changes are needed to prevent future reoccurrences. Once the investigation is completed, corrective measures need to be taken and implemented. It is important to communicate the findings to all parties involved and create a mechanism to track corrective actions in order to prevent future events. This analytical process enables a facility to shift the focus on preventing flaring events rather than reacting to them.

- Operator training for environmental awareness

Making the operators aware of the impact of flare events on the environment and teaching them procedures that minimize venting to flares needs to be part of the facility’s training program and should have full management support.

- Optimization of turnaround schedules

Coordination of turnaround schedules for different units can result in reducing flaring activity and minimize emissions associated with these periodic maintenance activities.

- Developing startup and shutdown procedures that do not use flaring

For certain units, it is possible to develop procedures that avoid flaring during shutdown and startup, such as using reduced loads, recycling feeds, better decontamination procedures, etc. Sometimes more time is necessary for a startup or shutdown, or physical modifications achieve this purpose.

C. FLARE GAS RECOVERY SYSTEMS

An alternative control option to minimizing the volume of vent gases routed to flares is to simply prevent the vent gases from being combusted in the flare by recovering them with a flare gas recovery system. In light of increasing environmental concerns, this flare gas recovery system control option is becoming popular, especially since there is an economic incentive due to recovery of valuable gas. The system usually consists of a set of compressors, a heat exchanger, a phase separator and associated pumps. The vent gas is compressed, cooled and routed to an amine scrubber for removal of sulfur compounds, and subsequently may be used as fuel gas or feed for refinery processes. A flare system generally consists of a header or manifold that collects the flare gases from various sources, a knockout drum, a liquid seal (usually water)
drum, and the flare itself. A flare gas recovery system unit connection is typically located between the knockout vessel and the flare water seal.

The primary control variable of the flare gas recovery system is the flare system pressure. As vent gases from various process units collect in the flare header, pressure reaches a predetermined pressure control set point, triggering the start up of the recovery compressor. The suction pressure of the compressor is set lower than that of the water seal, such that under normal operation, there is not enough pressure in the flare header to break through the liquid seal and all gas is recovered. During major upsets, if the flow exceeds the compressor capacity, the flare header pressure increases, breaking the liquid seal and the vent gases reach the flare, where they are combusted. Therefore, the safety function of the flare system is maintained in the event of process upset conditions.

In order to have a high recovery rate, the compressor station should be sized with a capacity two to three times the normal flare flow (Oil and Gas Journal, December 7, 1992). API Guideline 520 states that the normal flow rate is some average flare load or a frequently encountered maximum load and that the recovery system should be designed to operate over a wide range of dynamically changing loads. API 520 goes on to say that often these systems are installed to comply with local regulatory limits and therefore, must be sized to conform to any such limits.
CHAPTER III

PROPOSED RULE AMENDMENTS
CHAPTER III – PROPOSED AMENDMENTS

PROPOSED AMENDMENTS

Staff proposes amending Rule 1118 as follows:

- Add, modify or delete definitions.
- Add new operational requirements for flares and establish diagnostic practices to minimize flaring.
- Prohibit the flaring of gases other than those resulting from emergencies, shutdowns, startups, turnarounds and essential operational needs and require minimization of such flaring.
- Establish refinery specific performance targets for minimizing flare emissions based on annual crude throughput.
- Require refineries to pay a mitigation fee for exceedances of a refinery specific performance target.
- Require a Flare Minimization Plan and possible issuance of a Notice of Sulfur Dioxide Exceedance when flare SOx emissions exceed the facility specific target for a given year.
- Add and modify requirements for the Flare Monitoring and Recording Plan.
- Add and modify requirements for the operation monitoring and recording.
- Modify the recordkeeping requirements.
- Add new notification and reporting requirements.
- Expand and update the test methods.
- Modify and add exemptions.
- Enhance and update monitoring specifications in Attachment A – Flare Monitoring System Requirements.
- Modify and enhance Attachment B – Guidelines for Calculating Flare Emissions which include missing data substitution procedures.

A. DEFINITIONS

The following definitions are new:

- Emergency - is defined as a condition that requires immediate attention to restore normal operation, caused by a sudden, infrequent and unavoidable event. An emergency may be caused by equipment breakdown, natural disaster or an act of war or terrorism. If a repetitive flare event from the same equipment is caused by poor maintenance or a flare event results from careless operation, it will not be deemed an emergency.
- Essential Operational Need – is defined as flare event caused by a specifically listed operational or maintenance related activity where due its quality or quantity, the vent gas cannot be reasonably recovered, treated, used or delivered for sale with existing equipment. Examples of Essential Operational needs as determined by the Executive Officer are:

  Temporary fuel gas imbalances caused by inability of a customer to receive sales gas used for generation of electricity for a state grid or a third party contractual...
gas purchase agreement, or due to sudden shutdown of a combustion device for reasons other than operator error or poor maintenance;
Leakage of relief valves due to malfunction;
Venting of gas streams that are incompatible with the operation of the flare gas recovery equipment (e.g., molecular weight outside the design range) or that could pose a safety hazard to the fuel gas system (e.g., very low or very high BTU content that causes temperature swings in combustion devices, upsetting the process). Whenever the vent gas has a low BTU content a refinery may use supplemental natural gas or other clean gas that is compliant with Rule 431.1 to ensure high combustion efficiency;
Venting of clean gas streams to either a clean service flare or a general service flare;
Intermittent minor venting from sight glasses, compressor bottles, sampling equipment and pumps or compressors casings;
Emergency situations when the pressure vessel operating pressure rises above the set point of the pressure relief valve(s).

- Flare Gas Recovery System - is defined as any system designed to prevent or minimize the combustion of vent gases in a flare, composed of, but not limited to, compressors, heat exchangers, pumps, water seal drums, etc.
- Flare Minimization Plan is defined as a document that meets specific rule requirements in subdivision (e).
- Natural Gas - is defined as 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.
- Notice Of Sulfur Dioxide Exceedance – is defined as a notice that may be issued by the Executive Officer to a refinery in the event an annual performance target is exceeded and remains in its compliance record.
- Pilot - is defined as an auxiliary burner used to ignite the vent gas routed to a flare.
- Purge Gas - is defined as a continuous gas stream introduced in the 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.
- Sampling Flare Event – this definition replaces Recordable Flare Event and applies to flare events with a flow rate of at least 330 scfm for fifteen consecutive minutes or more, or any other flare event as approved in writing by the Executive Officer upon request from a facility, due to specific operational parameters of a flare. Sampling flare events that occur within 15 minutes of each other are considered a single event if the facility can demonstrate to the satisfaction of the Executive Officer that the events had a common cause and the release of vent gas originated from the same process unit.
- Shutdown - is defined as the procedure by which the operation of a process unit or piece of equipment is stopped at the end of a production run or for the purpose of performing maintenance, repair or replacement of equipment.
- Specific Cause Analysis - is defined as an investigation used to identify the cause of certain flare events with emissions exceeding either 100 pounds of VOC or 500 pounds of sulfur dioxide, or 500,000 standard cubic feet of flared gas, provide corrective measure(s), and prevent recurrence of a similar event.
- **Startup** - is defined as the procedure by which a process unit or piece of equipment achieves operational status. The attainment of normal operational status may be substantiated by parameters such as temperature, pressure, feed rate and also by products meeting quality specifications.

- **Turnaround** - is defined as a planned activity involving shutdown and startup of one or several process units for the purpose of performing periodic maintenance, repair, replacement of equipment, or installation of new equipment.

- **VOC** – is defined as in Rule 102 of AQMD Rules and Regulations.

The following definitions were modified:

- **Flare Event** - clarifies that an event takes place when vent gas is combusted in a flare and ends when the vent gas velocity drops below 0.12 feet per second, or when no more vent gas is combusted as demonstrated by the water seal monitoring record or other parameters as approved by the Executive Officer in the Flare Monitoring and recording Plan.

- **Flare Monitoring System** - was expanded to include, in addition to the flow meter, a continuous higher heating value analyzer and a total sulfur analyzer.

- **Gas Flare** - was shortened by removing “Gas” since this rule addresses flares used to dispose of gases only.

- **Hydrogen Plant** - was expanded to include the processes used to generate hydrogen.

- **Representative Sample** - was modified by deleting part of the definition that no longer applies or was moved under monitoring requirements.

- **Petroleum Refinery** – was expanded, for the purpose of this rule, to clarify that all portions of the petroleum refining operation, including those at non-contiguous locations operating flares, shall be considered as one petroleum refinery.

- **Sulfur Recovery Plant** - was expanded to also include sour gases as process feed.

- **Vent Gas** - was redefined as any gas generated at a refinery that is routed to a flare excluding assisted air or steam injected directly into the stack or flare combustion zone via a line separate from the flare header.

The following definition was deleted:

- **Recordable Flare Event** - was removed due to the new monitoring requirements and was replaced with “sampling flare event”.

**B. REQUIREMENTS**

Staff has added new requirements for flares, arranged by the date they become effective.

The following requirements become effective on January 1, 2006:

- A flare must have the pilot flames present any time the system it serves is in operation.

- All flares must operate without visible emissions, as determined by US EPA Method 22. The method allows for visible emissions for no longer than five minutes within a two consecutive hour period.
- All pressure relief devices (PRDs) connected directly to flares must have an annual inspection using acoustical or thermal surveys in order to detect leaks. The requirement applies only to PRDs venting directly to flares (gases that are not collected or controlled with flare gas recovery and treatment. The inspection has to be conducted within 90 days prior to a scheduled turnaround, if one is scheduled for that calendar year.

- The owner or operator of a flare having a flaring event with emissions exceeding either 100 pounds of VOC or 500 pounds of sulfur dioxide, or 500,000 standard cubic feet of vent gas combusted is required to conduct a Specific Cause Analysis of the event. Flare events associated with planned shutdowns, planned startups, and turnarounds are exempt from this requirement since their cause is known and therefore no investigation is necessary.

- The owner or operator of a flare has to identify the cause, where feasible, of any flare event where at least 5,000 standard cubic feet of vent gas was released to the flare. For some smaller releases, the owner or operator may not have sufficient data to determine the cause of the flare event.

The following requirements are effective January-September 1, 2007:

- The owner or operator of a refinery subject to this rule shall submit the technical detail of each flare system, including an audit of vent gas recovery capacity, an assessment of the flare gas reductions achieved since the adoption of Rule 1118 in 1998 and the planned future flare emission reductions.

The following requirements are effective January 1, 2007:

- The owner or operator of a refinery subject to this rule shall submit an evaluation of options to reduce flaring during planned events such as shutdowns, startups and turnarounds. The evaluation shall include, but is not limited to such options as slowing the depressurization of vessels, storing vent gases, etc.

- Owners or operators have to operate flares such that only vent gases resulting from an emergency, shutdown, startup, turnaround or essential operational need are combusted and have to minimize flare emissions during these events.

- Staff acknowledges that some refineries will install gas recovery and treatment system(s) to comply with this requirement, and that the refineries will need time to connect and operate these systems. In recognition of this need staff proposes to establish a compliance date of no later than January 1, 2009, or January 1, 2010 if more than two flares are to be controlled, provided that those refinery operators submit an application to construct and operate the control equipment for approval by the Executive Officer prior to January 1, 2007.

The following requirement is effective on January 1, 2009:

- Any vent gas combusted in a flare, except for vent gas resulting from an emergency, shutdown, startup, process upset or relief valve leakage, cannot exceed 160 ppm H₂S concentration, averaged over three hours. Staff believes that by January 1, 2009, most refineries will have sufficient vent gas recovery and treatment capacity to be able to comply with this requirement during essential operational needs, for which this requirement would essentially apply. Refineries needing to install gas recovery and treatment system(s) for more than two flares to comply with the requirements to limit and
Proposed Amended Rule 1118

minimize flaring under paragraph (c)(3), as well as this requirement to limit the H₂S concentration in the vent gas, will be granted a compliance date of January 1, 2010, to be consistent with the requirements of paragraph (c)(3), provided that those refinery operators submit an application to construct and operate the control equipment for approval by the Executive Officer prior to January 1, 2007.

C. PERFORMANCE TARGETS

PAR 1118 prohibits flaring of gases other than those resulting from emergencies, shutdowns, startups, turnarounds, and essential operational needs. It also sets decreasing flare total sulfur performance targets for the allowed flaring activities, calculated and reported as sulfur dioxide (SO₂), for subject refineries, based on 2004 throughput, with the purpose of capturing emission reductions achieved since the rule was adopted and to ensure that these and future emission reductions are enforceable, permanent, real, and verifiable. During the rule development process, industry identified an inequity of using crude throughput versus crude capacity based on a fixed year of 2004 to establish annual SO₂ performance targets. In any one year, any refinery could be conducting a shutdown or turnaround of a major crude processing unit, which could reduce crude throughput for that baseline year reflecting an artificially low baseline throughput for that refinery. Whereas crude processing capacity more accurately allocates refinery emissions based on normal refinery operations. Local refineries are operating at near capacity; therefore, the difference in emissions impact and reductions based on throughput or capacity are minimal. Total SO₂ reductions will be determined annually for each calendar year. To determine compliance with the SO₂ Performance Targets, the annual emissions will be divided by the 2004 refinery throughput, with the purpose of capturing emission reductions based on normal refinery operations. The performance targets proposed and the corresponding milestones, starting with year 2006, are as shown in Table III - 1:

<table>
<thead>
<tr>
<th>Year</th>
<th>2006</th>
<th>2008</th>
<th>2010</th>
<th>2012</th>
</tr>
</thead>
<tbody>
<tr>
<td>SO₂ Performance Target</td>
<td>1.5</td>
<td>1</td>
<td>0.7</td>
<td>0.5</td>
</tr>
</tbody>
</table>

In the event that a refinery exceeds the specified performance target in any calendar year, it will have to pay a mitigation fee for each ton of sulfur dioxide over the limit based on the following levels of exceedance: $25,000 for each and every ton where the exceedance is up to ten percent over the performance target, $50,000 for each and every ton where the exceedance is greater than ten percent but no more than twenty percent over the annual performance target, or $100,000 for each and every ton where the exceedance is greater than twenty percent over the applicable performance target. The mitigation cannot exceed $4,000,000 dollars per each petroleum refinery in any one year. Any mitigation fees paid would be used to implement emission reduction projects in the area impacted by the excess emissions.

It is expected that refineries will implement the procedures and install the equipment necessary to achieve compliance with the annual sulfur dioxide performance targets. However, since the operation of flares is variable based upon periodic events, some of which may be unforeseeable,
it is possible that a refinery could exceed a performance target in any one year. The mitigation fee provision offers the refinery an alternative compliance option in that circumstance and allows the opportunity for the refinery to take those actions necessary to ensure the performance targets are met in future years. For each year an annual performance target is exceeded, the Executive Officer may also issue a Notice of Sulfur Dioxide Exceedance that will become part of the petroleum refinery’s compliance record.

In establishing the appropriate monetary amount for the mitigation fees, staff considered two larger petroleum refineries that currently have no or limited controls on their flares. Historical flare sulfur dioxide (SO\(_2\)) emissions and flare vent gas flows for the two facilities for the years 2002, 2003 and 2004 and the three year average are shown in Table III - 2.

<table>
<thead>
<tr>
<th>Table III – 2</th>
<th>Historical Data</th>
</tr>
</thead>
<tbody>
<tr>
<td>Refinery 1</td>
<td>2002</td>
</tr>
<tr>
<td>SO(_2) (tons/year)</td>
<td>59</td>
</tr>
<tr>
<td>Flow (million cubic feet per year)</td>
<td>804</td>
</tr>
<tr>
<td>Refinery 2</td>
<td>2002</td>
</tr>
<tr>
<td>SO(_2) (tons/year)</td>
<td>77</td>
</tr>
<tr>
<td>Flow (million cubic feet per year)</td>
<td>308</td>
</tr>
</tbody>
</table>

As part of their 2004 Emissions Fee Billing (EFB) submittal, Refinery 1 and Refinery 2 reported processing of approximately 95 and 51, million barrels of crude oil during the 2003-2004 fiscal year, respectively. Table III-3 is a summary of the permitted annual crude oil throughput (in million barrels of crude oil per year), the 2010 SO\(_2\) performance target for each petroleum refinery target (in tons SO\(_2\)), and the amount of SO\(_2\) exceedance at twenty percent over the 2012 annual SO\(_2\) performance target of 0.5 tons per million barrels of crude oil.

<table>
<thead>
<tr>
<th>Table III – 3</th>
<th>Analysis</th>
</tr>
</thead>
<tbody>
<tr>
<td>Facility</td>
<td>Annual Crude Oil Throughput (million barrels)</td>
</tr>
<tr>
<td>Refinery 1</td>
<td>93</td>
</tr>
<tr>
<td>Refinery 2</td>
<td>50</td>
</tr>
</tbody>
</table>

To estimate the vent gas flow associated with the 10 tons and 5 tons of sulfur dioxide excess emissions, staff will use the ratio of three year average of vent gas flow to SO2 emissions. Staff believes that the total flow and SO2 emissions for any year will average the high and low flows and SO2 emissions that will be used to determine the approximate vent gas flow for the sulfur dioxide excess emissions.

Therefore, the flow associated with the yearly exceedance, in million standard cubic feet per year (mmscfy) and calculated as daily, averaged over 365 days (mmscfd) is:
Refinery 1:

Flow$_1$ = 10 tons * 755 mmscfy / 54 tons = 140 mmscfy = 0.38 mmcf/d

Refinery 2:

Flow$_2$ = 5 tons * 307 mmscfy / 47 tons = 33 mmscfy = 0.09 mmcf/d

To prevent future exceedances, it is assumed that the two facilities would have to install flare gas recovery and treating systems to control this amount of vent gas associated with the SO$_2$ exceedance. The capacity of the control system should be two to three times the vent gas flow rate; staff has determined the cost of a flare gas recovery and treating system to be $2.17 million per million standard cubic feet per day (mmcf/d) of vent gas recovery/treatment (see discussion in Chapter VI).

The cost to install vent gas recovery and treatment to control the incremental amount of sulfur dioxide that caused the exceedance of the annual performance target is:

Refinery 1

Control Cost = 0.38 mmcf/d * 2 * $2.17 million per mmcf/d / 10 tons per day
= $164,920 per ton SO$_2$ reduced

Refinery 2

Control Cost = 0.09 mmcf/d * 2 * $2.17 million per mmcf/d / 5 tons per day
= $78,120 per ton SO$_2$ reduced

The average cost to control the incremental amount of sulfur dioxide that caused the exceedance of the annual performance target is $121,520. As previously stated, the operation of flares and resultant emissions are variable based upon periodic events. Therefore, a mitigation fee of $100,000 per ton of SO$_2$ for annual exceedances of more than twenty percent of the annual performance target is appropriate. The mitigation fee for exceedances less than twenty percent are less than the cost of vent gas recovery and treatment and therefore would be considered reasonable.

D. FLARE MINIMIZATION PLAN REQUIREMENTS

Each refinery that exceeds an annual performance target must submit a Flare Minimization Plan to the AQMD for approval from the Executive Officer, along with appropriate fees pursuant to Rule 306 but no later than 90 days from the end of the calendar year when the performance target was exceeded that demonstrates the actions to be taken to achieve the performance targets. The main required elements of the plan are:

- A complete description and technical specifications for each flare at a facility;
- Detailed process flow diagrams of upstream equipment venting to each flare and an identification of all control equipment;
- Policies and procedures, as well as any additional equipment, to be used to minimize vent gases during emergencies, shutdowns, startups and turnarounds and during essential operational needs; and

- A complete description of a flare gas recover and treatment system(s) to be installed to meet the performance target(s).

The AQMD will make available the Flare Minimization Plans, less any confidential information, for public comments for a period of 60 days and respond to them prior to taking action on the plans. Any facility that exceeds it annual sulfur dioxide emission limit during a subsequent calendar year will have to submit to the AQMD a revised Flare Minimization Plan within 90 days from the end of the calendar year, in which it will detail additional measures for preventing future exceedance. If the Executive Officer deems the plan deficient, the facility has 45 days to correct and resubmit it. Failure to do so would cause the Executive Officer to deny the plan and issue the facility a Notice of Violation.

A facility may, without exceeding the performance targets and on a voluntary basis, submit a Flare Minimization Plan for approval to the Executive Officer. The plan would be subject to the same provisions as a mandatory plan, but if denied no Notice of Violation would be issued to the facility.

E. FLARE MONITORING AND RECORDING PLANS

Each existing facility currently in operation must submit a revised Flare Monitoring and Recording Plan by June 30, 2006 for approval by the AQMD, along with appropriate fees pursuant to Rule 306. Any new facility or non-operating facility that starts operating after the rule is amended will have to submit a Flare Monitoring and Recording Plan and appropriate fees at least 180 days prior to initial start-up and notify the AQMD seven days prior to startup or resumption of operations. The current monitoring plans submitted pursuant to Rule 1118, adopted February 13, 1998 will be in effect until the revised plans are approved by the AQMD. The revised plans must provide, in addition to the existing information, details on installed heat content analyzers, total sulfur analyzers and upgraded flow meters, where applicable.

F. OPERATION MONITORING AND RECORDING

The proposed amendment has several new requirements for flare monitoring and recording. The new requirements will be phased in as follows:

Effective upon rule amendment January 1, 2006:

- The presence of a flare pilot flame has to be monitored using a thermocouple or an equivalent device, such as infrared or ultraviolet cameras.

- Refineries will have to use video monitors equipped with date and time stamp to monitor the flares for visible emissions. The video recording will have to be maintained at the facility for a period of 90 days and submitted to AQMD personnel upon request.

Effective January 1, 2006:

- Facilities subject to this rule are required to take a daily representative sample. Only one representative sample is required each day for flare events that are not sampling flare events. A representative sample collected for a sampling flare event on that day may be used to satisfy this requirement. For flare events lasting 15 minutes or less, no
representative sample is required. A sample shall not be required if the operator demonstrates vent gas is not routed to a flare based on 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.

Effective July 1, 2006:
- Refineries will have to use video monitors equipped with date and time stamp to monitor the flares for visible emissions. The video recording will have to be maintained at the facility for a period of 90 days and submitted to AQMD personnel upon request.

Within six months from approval of the Flare Monitoring and Recording Plan, but no later than July 1, 2007:
- Continuous higher heating value and semi-continuous total sulfur analyzers are required for emergency and general service flares to eliminate problems related to sampling and data accuracy, as recommended in the Evaluation Report on Emissions from Flaring Operations at Refineries. The use of analyzers will provide a more realistic picture of flare emissions by providing more data points for the heat content and total sulfur content of the vent gases, thus increasing the accuracy and reliability of emission reporting, that is currently achieved by using data from weekly samples. Refineries must begin monitoring within six months from approval of the Revised Flare Monitoring and Recording Plan by the AQMD. Until the analyzers are installed and certified by the Executive Officer, the refineries will be required to measure and sample for both higher heating value and total sulfur daily (an increase from the current weekly sampling requirement) in addition to collecting representative samples during a sampling flare event, using a step by step procedure outlined in Table 21 (Effective Until June 30, 2007), footnote 4 of the proposed amended rule. However, if no flare event takes place during the day, as demonstrated by water seal level records or other parameters as approved in the Flare Monitoring and Recording Plan, no sample is required. In the event that samples cannot be taken due to an exempt occurrence and emissions are estimated, the methods are those in the missing data procedures included in an appendix to the rule and estimated emissions have to be reported as such in the quarterly flare report.

Effective January 1, 2007:
- Flow meters are required for monitoring and recording the purge gas and pilot gas flow rates for all emergency and general service flares and have to be approved by the AQMD.
- All emergency and general service flare flow meters will have to be installed at a representative location to indicate an accurate flow to the flare. This requirement was necessary since there are flow meters located upstream of water seals at flares equipped with flare gas recovery systems that may indicate a flow that actually is recovered and not breaking the water seal. The operators monitor the water seal level to determine whether an actual flare event took place. There are also problems at low flows, when ambient heat creates a gas flow inside the large diameter flare headers, resulting in a “ghost” reading on the flow meter. In order to eliminate these problems, flow meters have to be installed downstream of water seals or, if this is not feasible due to physical
constraints, they need to be equipped with totalizing capability that discounts reverse flows to a recovery compressor or due to turbulence created by ambient heat.

- Each emergency and general service flare that is not equipped with a total sulfur analyzer will have to be equipped with an automated sampling system capable of alerting the operator that a sampling event has started.

G. RECORDKEEPING REQUIREMENTS

The proposed amendment requires that video recordings of all flares be kept for 90 days and all other records mandated by the rule be kept for a period of five years.

H. NOTIFICATION AND REPORTING

The proposed amendment has new notification requirements and enhanced reporting requirements, as follows:

- Facilities subject to this rule will have to 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.

- Refineries will have to notify the AQMD by telephone within one hour of a flare event exceeding 100 pounds of VOC, 500 pounds of total sulfur emissions calculated as sulfur dioxide, or 500,000 standard cubic feet of vent gas. The one-hour time requirement starts at the time the refinery operator facility knows or should have known that the aforementioned mass levels may have been emitted or the vent gas as measured by the flow meter is determined to exceed 500,000 standard cubic feet of vent gas. A “specific cause analysis”, identifying the cause and duration of the event, mitigation and corrective actions taken, has to be submitted to the AQMD within 30 days.

- A 24-hour advance notice to the AQMD is required for scheduled planned flare events that have the potential to exceed 100 pounds of VOC or 500 pounds of total sulfur, calculated as sulfur dioxide or 500,000 standard cubic feet of vent gas.

- The quarterly reports will have to be submitted in an electronic format approved by the AQMD and certified in writing by a responsible facility official that the information is true and accurate. Emissions will have to be calculated or, in case of missing data, substituted using the guidelines in Attachment B to the rule. The refineries will also have to include in the quarterly report a categorization of flare events by cause and the associated emissions. Lastly, records of leak surveys done in the quarter for pressure relief devices connected to flares will have to be reported, including identification of the devices, dates of inspection and the person(s) conducting the surveys.

I. TEST METHODS

The following are additions and modifications to this section of the rule:

- The higher heating value of the flare vent gas has to be monitored with a semi-continuous analyzer meeting or exceeding the specifications in Attachment A to the rule.

- Total sulfur concentration calculated as sulfur dioxide may be monitored with a semi-continuous total sulfur analyzer meeting or exceeding the requirements in Attachment A.
to the rule. Until such time as the monitor is certified by the Executive Officer, the samples collected by the refinery operator shall be determined using AQMD Method 307-91 or updated ASTM Method 5504-01.

- The accuracy of the flare flow meters has to be verified annually according to manufacturer’s procedures.
- For determining visible emissions from flares, refineries have to use procedures outlined in U.S. EPA Method 22, 40CFR Part 60 Appendix A.

**J. EXEMPTIONS**

An exemption was added for excluding the flare-related total sulfur emissions, calculated as sulfur dioxide, resulting from external power curtailments excluding interruptible service agreements, natural disasters and acts of war or terrorism, from the annual facility emissions established under Performance Targets since these events are beyond the reasonable control of the refinery operator. In addition, has added language to clarifying that sampling and analyses of representative samples for higher heating values and the concentration of total sulfur, expressed as sulfur dioxide, pursuant to paragraph (g)(3) may not be required for any flare event when collecting a sample is unfeasible or constitutes a safety hazard.

**K. ATTACHMENT A**

Attachment A was enhanced by incorporating additional specifications for the continuous flow measuring device and adding new specifications for the heat content analyzer and the total sulfur analyzer.

**L. ATTACHMENT B – GUIDELINES FOR CALCULATING FLARE EMISSIONS**

Attachment B was modified to include equations and emission factors for calculating flare emissions for vent gas, natural gas, propane and butane, thus making reporting uniform among refineries, sulfur recovery plants and hydrogen production plants. Another addition provides the methodology to be used for data substitution during flow meter, sampling and analyzer down periods or when the representative samples are not measured and recorded pursuant to the rule requirements. Data substitution is not required if it can be demonstrated to the satisfaction of the Executive Officer that there was no flow to the flare during the flow meter and/or analyzer outage or a sample was not taken and analyzed. Footnote 4 in Table 1 of Rule 1118 further explains that samples specified in Table 1 will not be required if the operator demonstrates that vent gas is not being routed to a flare based on 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 Revised Flare Monitoring and Recording Plan.

Once the methodology and parameters used to demonstrate that the vent gas is not being routed to a flare is included in the approved Flare Monitoring and Recording Plan or Revised Flare Monitoring and Recording Plan, it is considered to be to the satisfaction of the Executive Officer for the purpose of making the above demonstration. If there was flow, the method shown in equation (1) shall be used to calculate the substituted data, unless an alternate method using recorded and verifiable operational parameters and/or process data is approved by the Executive Officer to be representative of the missing parameters, including reference to similar events that occurred previously. The goal of the data substitution methodology was to provide a conservative estimate based on the operational history of the flare.
\[ MP = P_{\text{Max}} - 0.5 \times (P_{\text{Max}} - P_{\text{Avg}}) \]  

Equation (1)

where:

\[ MP = \text{The missing parameter for which data was not recorded.} \]

\[ P_{\text{Max}} = \text{Maximum measured and recorded value of the missing parameter over a 5 year period.} \]

\[ P_{\text{Avg}} = \text{Average measured and recorded value of the missing parameter over a 5 year period.} \]

This methodology was developed based on the reported flare event data for refineries operating in the South Coast Air Basin (including a sulfur plant) between October 1, 1999 through June 30, 2005. The data reported by the refineries and utilized in the analysis included:

- The duration of each individual flare event;
- The total volume of gas released during the flare event;
- The higher heating value of the flared gas;
- Basis for which the higher heating value (HHV) of the flared gas was determined (lab measurement, average of previous events, etc.);
- The sulfur content of the flared gas; and
- Basis for which the concentration of total sulfur, expressed as sulfur dioxide, of the flared gas was determined (lab measurement, average of previous events, etc.).

Data whose origin was not based on a discrete measurement was discarded. It was discarded so the entirety of the data being analyzed would be representative of actual flare events. This would prevent variability in the data being attenuated through the introduction of substitute data based on an average.

The data for each recorded flare event between October 1999 and June 2005 for each flare were plotted as a function of time. These plots revealed:

- The concentration of total sulfur, expressed as sulfur dioxide, in the flared gas showed a high degree of data scatter that varied randomly over a potential range of 200,000 ppm.
- The volume of gas flared in terms of rate and total volume released showed a high degree of data scatter which varied randomly over a potential range of 39,000 MSCF.
- The HHV of the flared gas exhibited the lowest degree of data scatter, but still varied randomly. The magnitude of the variation was over a potential range of 5000 Btu/scf.

The large range and randomness exhibited by the population of data posed the following difficulties in creating a methodology for estimating substitute data:
• Requiring the facility to report substitute data based on the single highest historical measured value would result in the facility grossly over-estimating their emissions. The emission would be grossly over-estimated as a result of the majority of the flares having a single point outlier for each data set that was orders of magnitude greater that the majority of the population.

• Requiring the facility to report an average value would result in a significant portion of the data falling above the mean value. There would be a large portion of data above the mean value due to the high degree of data scatter exhibited by the population of data.

• A methodology based on a short term sample of data could result in substitute data being under-estimated. The data would be under-estimated if the short term sample happened to be taken from a period where the values of the short term population were on a down-trend. There were flares in the analyzed data set, which included 23 consecutive quarters (5 years, 9 months) of reported data that demonstrated cyclic behavior. Coincidently, the refineries have stated that they turnaround their units every five years. This behavior showed surges in the value of a given parameter, followed by a lull. Any data that were estimated based on the lull period would provide under-estimated results during the surge, which is contrary to the goal of the substitution methodology.

The method shown in Equation (1) accounted for the problems listed above. This method accounts for the average value of the population with respect to the deviation from the mean. The use of a five year (20 quarters) averaging period also eliminates the potential of under-estimating substitute data due to basing it’s value on a short term period where the value of the population could be in a lull. The 0.5 multiplier in equation (1) was empirically determined by fitting the equation to the population of data. The equation was fit multiple times with the multiplier incrementally increased between a range of 0.4 and 0.7. The 0.5 multiplier provided the desired result. This value provided a result that generally captured 98% of the population of data, but was sufficiently less than the single point outliers that were present in some populations of data.
CHAPTER IV

EMISSION INVENTORY
A. CONTRIBUTING SOURCES

As shown in Chapter I, in the AQMD there are seven petroleum refineries, one sulfur plant and one hydrogen generating plant accounting for 27 flares categorized as emergency flares, clean flares and general purpose flares. The breakdown by flare, as reported in the September 2004 Evaluation Report, including flare system design and flare gas recovery capacities, is shown below in Table IV – 1.

<table>
<thead>
<tr>
<th>Flare ID</th>
<th>Capacity (lbs/hr)</th>
<th>Vapor Recovery Capacity (MMscfd)</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>Flare No. 1</td>
<td>41,000</td>
<td>0.36</td>
<td></td>
</tr>
<tr>
<td>Flare No. 2</td>
<td>232,281</td>
<td>6.96*</td>
<td></td>
</tr>
<tr>
<td>Flare No. 3</td>
<td>1,120,000</td>
<td>1.4*</td>
<td></td>
</tr>
<tr>
<td>Flare No. 4</td>
<td>600,000</td>
<td>None</td>
<td></td>
</tr>
<tr>
<td>Flare No. 5</td>
<td>343,900</td>
<td>None</td>
<td>Clean Flare</td>
</tr>
<tr>
<td>Flare No. 6</td>
<td>1,300,000</td>
<td>2</td>
<td></td>
</tr>
<tr>
<td>Flare No. 7</td>
<td>250,000</td>
<td>None</td>
<td></td>
</tr>
<tr>
<td>Flare No. 8</td>
<td>1,040,000</td>
<td>4.8</td>
<td></td>
</tr>
<tr>
<td>Flare No. 9</td>
<td>956,000</td>
<td>None</td>
<td></td>
</tr>
<tr>
<td>Flare No. 10</td>
<td>133,950</td>
<td>6.96*</td>
<td></td>
</tr>
<tr>
<td>Flare No. 11</td>
<td>825,000</td>
<td>None</td>
<td></td>
</tr>
<tr>
<td>Flare No. 12</td>
<td>6,000</td>
<td>None</td>
<td>Clean Flare</td>
</tr>
<tr>
<td>Flare No. 13</td>
<td>1,300,000</td>
<td>6</td>
<td></td>
</tr>
<tr>
<td>Flare No. 14</td>
<td>26,718</td>
<td>None</td>
<td>Clean Flare</td>
</tr>
<tr>
<td>Flare No. 15</td>
<td>3,540,000</td>
<td>9.8</td>
<td></td>
</tr>
<tr>
<td>Flare No. 16</td>
<td>176,000</td>
<td>None</td>
<td></td>
</tr>
<tr>
<td>Flare No. 17</td>
<td>960,000</td>
<td>6</td>
<td></td>
</tr>
<tr>
<td>Flare No. 18</td>
<td>1,400,000</td>
<td>6</td>
<td></td>
</tr>
<tr>
<td>Flare No. 19</td>
<td>173,000</td>
<td>None</td>
<td></td>
</tr>
<tr>
<td>Flare No. 20</td>
<td>188,000</td>
<td>None</td>
<td></td>
</tr>
<tr>
<td>Flare No. 21</td>
<td>1,220,000</td>
<td>1.25</td>
<td></td>
</tr>
<tr>
<td>Flare No. 22</td>
<td>655,000</td>
<td>1.4*</td>
<td></td>
</tr>
<tr>
<td>Flare No. 23</td>
<td>26,000</td>
<td>None</td>
<td></td>
</tr>
<tr>
<td>Flare No. 24</td>
<td>335,847</td>
<td>6.96*</td>
<td></td>
</tr>
<tr>
<td>Flare No. 25</td>
<td>498,000</td>
<td>None</td>
<td></td>
</tr>
<tr>
<td>Flare No. 26</td>
<td>1,407,000</td>
<td>6</td>
<td></td>
</tr>
<tr>
<td>Flare No. 27</td>
<td>70,000</td>
<td>0.06</td>
<td>Clean Flare</td>
</tr>
</tbody>
</table>

* These flares share a flare gas recovery system

Table IV – 1
Flare Inventory
B. EMISSION INVENTORY

According to the 2003 AQMP, the SO\textsubscript{2} emissions inventory for refinery flares, based on the 1997 annual reports for emissions fee billing (EFB), is 4.14 tons per day (the initial number, based on unaudited data at the time the AQMP was published, was 4.4 tons per day). For 2006 and 2010, this inventory is projected to be reduced by 50 percent through the implementation of Step II of control measure CMB-07, and the AQMP assumes concurrent emission reductions for the other criteria pollutants. The proposed amendment of Rule 1118 will implement Step II of the control measure and further reduce emissions to the extent feasible.

Flare emissions are reported on a quarterly basis per current requirements in Rule 1118, and are calculated based on flare vent gas flows and weekly samples that are analyzed to determine the concentration of total sulfur, expressed as sulfur dioxide, and the higher heating value (HHV) of the vent gas. It has to be noted that these emissions are different from the annual emissions reported under EFB program, where reported flare emissions are calculated based on crude throughput and the amount of elemental sulfur produced at each facility, using appropriate emission factors.

A summary of the quarterly reports, showing Rule 1118 annual flare emissions, from 2000 through 2003, extracted from the September 2004 report presented to the Governing Board and the reported flare emissions for 2004 is shown in Table IV – 2.

<table>
<thead>
<tr>
<th>Year</th>
<th>Flow (mmscf)</th>
<th>NOx</th>
<th>VOC</th>
<th>CO</th>
<th>PM10</th>
<th>SOx</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>2000</td>
<td>4,085</td>
<td>136</td>
<td>125</td>
<td>733</td>
<td>43</td>
<td>2,633</td>
<td>3,670</td>
</tr>
<tr>
<td>2001</td>
<td>8,324</td>
<td>380</td>
<td>456</td>
<td>2,058</td>
<td>87</td>
<td>1,793</td>
<td>4,774</td>
</tr>
<tr>
<td>2002</td>
<td>2,440</td>
<td>83</td>
<td>78</td>
<td>450</td>
<td>25</td>
<td>754</td>
<td>1,390</td>
</tr>
<tr>
<td>2003</td>
<td>2,235</td>
<td>79</td>
<td>75</td>
<td>423</td>
<td>23</td>
<td>735</td>
<td>1,335</td>
</tr>
<tr>
<td>2004</td>
<td>2,392</td>
<td>93</td>
<td>70</td>
<td>364</td>
<td>27</td>
<td>352</td>
<td>906</td>
</tr>
</tbody>
</table>

The data in the table shows that flare emissions have decreased in the years following the adoption of the rule in 1998, as the refineries became more sensitive to flaring issues and implemented voluntary measures to reduce the vent gas flow combusted in the flares and better managed flare operations. It is important to note that these voluntary reductions in flare gas flow and associated emission reductions were generally not achieved through the installation or modification of gas recovery capacity or flare gas treatment systems. Since 1998, only one local refinery has installed control equipment in 2001; a flare gas recovery system for one of its flares that resulted in significantly reduced emissions from that flare.
Another reason for the drop in emissions was found to be the correct measurement of flare flows. A refinery discovered it had erroneous flare flow readings that led to reporting inflated emissions. An investigation of the problem concluded that the flow meter located before the water seal was counting both the flow towards the flare and the reverse flow to a recovery compressor, although no actual vent gas was going past the water seal and combusted in the flare. The refinery relocated the flow meter in the flare stack and eliminated the problem. Therefore, in order to get reliable emission data, it is necessary that the flow meters be located in a representative location after the water seals to ensure that a true flow to the flare is registered, or they must be equipped with totalizing capability to subtract any reverse flows to flare gas recovery systems.

The rest of the reductions resulted primarily from voluntary changes in operations, such as extending the time for shutting down or starting up units to minimize flaring, training operators to avoid routine flaring, as well as a commitment from management to minimize flaring. However, none of these measures are required by the current rule and as such, are not considered enforceable and permanent.

An analysis of the flare flow, events, and emissions data submitted to the AQMD since 1999 clearly shows a downward trend, it also shows variability from year to year. This variability is due in large part to emergencies, the specific unit(s) that undergo turnaround(s) in that year, other startups and shutdowns, and essential operational needs. Since these events can vary year to year, so will the number and type of flare events and the flare emissions. Therefore, it is appropriate to average the annual flare emissions to develop a representative baseline emissions inventory for emissions reductions and cost analysis calculations. Based on an analysis of the data submitted and discussions with refinery representatives, staff concluded that the 2000 data may not be very reliable due to compliance issues and because of problems related to the implementation of this recently adopted flare monitoring rule. Also, one refinery installed additional vent gas recovery in 2001; this installation would result in permanent emissions reductions from 2002 and beyond. Therefore, staff has determined that the most representative data for these variable flare operations and future releases are from years 2002, 2003 and 2004.

<table>
<thead>
<tr>
<th>Year</th>
<th>NOx (TPY)</th>
<th>NMHC (TPY)</th>
<th>CO (TPY)</th>
<th>PM10 (TPY)</th>
<th>SO2 (TPY)</th>
<th>Total (TPY)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Average Emissions</td>
<td>85</td>
<td>74</td>
<td>412</td>
<td>25</td>
<td>613</td>
<td>1,209</td>
</tr>
<tr>
<td>Average Emissions (TPD)</td>
<td>0.23</td>
<td>0.20</td>
<td>1.13</td>
<td>0.07</td>
<td>1.68</td>
<td>3.31</td>
</tr>
</tbody>
</table>

Based on emissions data from Table IV – 2, Table IV – 3 shows the flare emissions average for the period 2002 through 2004. The Rule 1118 average reported SO2 emissions is 613 tons or 1.68 tons per day, while the average emissions total for all the criteria pollutants is 1,209 tons, or 3.31 tons per day. This inventory will be used as the baseline for calculating the emission reductions associated with the proposed amended rule and its cost effectiveness.
CHAPTER V

EMISSION REDUCTIONS
As shown in the previous chapter, flare emissions have trended lower since the rule was first adopted in 1998. As monitoring of flare flows was initiated to comply with the rule, refinery operators became aware of the high amounts of vent gas routed to flares and implemented procedures to minimize emissions. Although the reductions are substantial, staff believes that further emission reductions are feasible for the industry. In September 2004, after staff presented the “Evaluation Report on Emissions from Flaring Operations at Refineries”, the AQMD Governing Board directed staff to initiate the amendment of Rule 1118. The performance targets in this rule amendment will result the installation of additional controls for flaring operations, as recommended in the Evaluation Report, to prevent backsliding in the emissions that have been reduced over the last several years.

The proposed amended rule requires refineries to gradually lower their annual sulfur dioxide emissions from a baseline average of approximately 1.68 tons per million barrels of crude processed to 1.5 tons per million barrels of crude processed in calendar year 2006, 1.0 ton per million barrels of crude processed in calendar year 2008, 0.7 ton per million barrels of crude processed in calendar year 2010 and 0.5 ton per million barrels of crude processed in calendar year 2012. The total processing capacity of the refineries in the basin, based on industry data, is approximately 1 mmbbl/day, therefore projected annual sulfur dioxide emissions for 2012 are 430.7 tons.

These reductions can be achieved by establishing a requirement that limits the use of flares only for emergencies, shutdowns and startups and certain essential operational needs and elimination of routine flaring. To ensure that total industry emissions will stay below the limit and prevent backsliding, the proposed amended rule has a mitigation fee provision in place. However, staff believes that by year 2012, flare sulfur dioxide emissions will be well below 0.5 ton per day and does not expect that any facility will have to pay mitigation fees, based on the current downtrend in emissions and the effect of the controls in the proposed rule amendment.

As the refineries minimize the amount of vent gas sent to flares, there will be concurrent emission reductions of other criteria pollutants. This is due to the fact that concurrent emissions are calculated as a function of the flare vent gas volume and the heating value of the flare gas. It is assumed that, since the average heating value of the vent gas is expected to stay constant, the lower vent gas volume will translate into proportionally lower emissions of NOx, CO, ROG and PM10.

Refineries E and H have reported significantly higher flare flows when compared to other refineries since the rule was adopted. During the interviews staff had conducted with all refineries subject to PAR 1118, Refinery H has informed staff that it has completed a flare gas optimization project in 2004 and that an additional flare gas recovery system will also be installed by 2008; moreover, Refinery E has also committed to the AQMD to increase its vapor recovery and gas treating capacity and to install flare gas recovery systems to significantly reduce flare emissions.

Staff has calculated the average total flare flow and a breakdown of the reasons for venting for 2001 through 2003, which can be found in Table V – 1. This information was based on data from the September 2004 “Evaluation Report on Flares at Petroleum Refineries.” For the same reason as explained before, the data for year 2000 and 2001 was not included in the calculation of the average flow since the 2000 flow data was determined to be unreliable and a flare gas recovery system was installed at one refinery in 2001, which significantly reduced emissions from one of its’ flares.
As stated in Table V – 1, emergencies, maintenance, start-ups and shutdowns, turnaround activities, process vent and fuel gas imbalances represent approximately 53 percent of the total flow. The remaining 47 percent represents the volume of non-recordable and unknown non-emergency events that has a potential to be recovered/minimized.

Based on an analysis of the reported flare data and discussions with two “larger” of the three facilities that have been identified in the staff report as needing additional gas recovery and treatment system capacity to comply with PAR 1118, staff has determined that Refineries E, F and H will install flare vent gas recovery and treatment systems with a maximum capacity of 13.3 million standard cubic feet per day (mmscfd). The average capacity of 9 mmscfd is equivalent to 3,285,000 mscf per year (see Chapter VI – Cost and Cost Effectiveness for additional discussion and analysis of these vent gas recovery and treatment systems). This average recovery and treatment capacity represents more than 100 percent of the average annual flare flow, as found in Table V-1. Staff anticipates other refineries will initiate additional measure to minimize vent gases being sent to the flares. Therefore, with the increase in vent gas recovery and treatment capacity and additional voluntary flare minimization measures to be implemented, staff has determined that the baseline (three year average) emissions of criteria air contaminants other that sulfur dioxide will be reduced by 75 percent or more. Sulfur dioxide emissions will be reduced from the baseline of 1.68 tons per year to 0.5 ton per year by year 2012.

From the baseline emissions inventory representing the 2002-2004 annual emissions averages and using the emissions reduction analysis above, the projected 2012 flare emissions are as shown in Table V – 2. Although actual sulfur dioxide emission reductions are anticipated to be significantly higher than what it is assumed in this table, for the purpose of this analysis, emission reduction estimates were based on the 2012 annual sulfur dioxide performance target of 0.75 ton per million barrels of crude processed for PAR 1118.
Table V-2
Summary of AQMD Emission Reductions (Tons per Year)

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>Year</th>
<th>Emissions Reductions</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Baseline</td>
<td>2012</td>
</tr>
<tr>
<td>SO₂</td>
<td>613</td>
<td>183</td>
</tr>
<tr>
<td>NOx</td>
<td>85</td>
<td>38</td>
</tr>
<tr>
<td>PM10</td>
<td>25</td>
<td>10</td>
</tr>
<tr>
<td>VOC</td>
<td>74</td>
<td>41</td>
</tr>
<tr>
<td>CO</td>
<td>412</td>
<td>198</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>1,209</strong></td>
<td><strong>470</strong></td>
</tr>
</tbody>
</table>
CHAPTER VI

COST AND COST-EFFECTIVENESS
CHAPTER VI – COST AND COST EFFECTIVENESS

FINAL STAFF REPORT

A. COSTS

The proposed amendment seeks to implement the most feasible and cost-effective control options in order to reduce flare emissions. This chapter presents an overview of the costs refineries will have to incur in order to comply with the new requirements and the cost-effectiveness of implementing these requirements.

Since the proposed rule will only allow venting of vent gases during an emergency, shutdown, startup, turnaround or essential operational need and to minimize flaring, it is assumed that some refineries will need to install new flare gas recovery and gas treating systems, whereas other refineries may have to increase their existing flare gas recovery and treating capacity in order to comply with this proposed rule requirement. These are technologically feasible pre-combustion controls that were suggested in the conclusion of the “Evaluation Report on Emissions from Flaring Operations at Refineries” presented to the AQMD Board on September 3, 2004.

As shown in Table IV-1, of the seven oil refineries subject to the rule, three do not have any flare gas recovery for their flares. Staff expects these three refineries to install flare gas recovery systems and additional gas treating capacity. Based on the last four years, the other four refineries have adequate flare gas recovery capacity and are not expected to incur significant control equipment costs to comply with the proposed amended rule.

In order to meet the monitoring requirements, the refineries where the flow meters are located before the water seals at flares equipped with flare gas recovery compressors will need to upgrade the flow meters with totalizing and low flow measurement capability to accurately indicate the actual vent gas flow to the flare. Also, flow meters will need to be installed on all flares for the measurement of the purge and pilot gas flow. All refineries will have to equip their emergency and general purpose flares with heat content analyzers and total sulfur analyzers.

Until the analyzers are certified by the Executive Officer, refinery operators will be required to conduct sampling for both higher heating value and total sulfur daily. If the total sulfur analyzer pilot program to be conducted in 2006 demonstrates that the current sulfur monitoring technology is not feasible, an additional cost for automated sampling systems and the processing of samples for total sulfur content must be included in the costs to implement PAR 1118.

Staff will calculate the costs associated with the proposed amendment; two scenarios will be considered. Costs common to both scenarios include additional vent gas recovery and treatment systems (capacity), upgrade flare gas flow meters, install purge/pilot gas flow meters, and annual costs associated with the newly installed equipment (parts and maintenance), surveys of pressure relief devices, conducting flow meter tests and Specific Cause Analyses. In Scenario 1, it will be assumed that all of refineries will install heat content and total sulfur analyzers. In Scenario 2, it will be assumed that only heat content analyzers are installed along with automated sampling systems and that the concentration of total sulfur, expressed as sulfur dioxide, of the vent gas will be determined by laboratory analysis.

Scenario 1

Capital Costs

Under the first scenario, it will be assumed that:

- The three refineries that currently do not have flare gas recovery systems (for eight flares) will install a total of four flare gas recovery and gas treating systems. Staff assumes that
at the first refinery, two systems will be installed; one system will control three flares and the other two flares. Another system serving a pair of flares will be installed at the second refinery. The third refinery will install one control system for its one flare.

- Refineries will install 23 heat content analyzers for the emergency/general service flares;
- Refineries will install 23 total sulfur analyzers for the emergency/general service flares;
- Refineries will install 50 purge/pilot gas flow meters (one for each emergency/general service flare); and
- Refineries will upgrade the emergency/general service flare flow meters with totalizing and low flow capability.

A synopsis of the projected rule required changes for emergency and general service flares is shown in Table VI-1.

### Table VI – 1
**Scenario I Rule Required Modifications**

<table>
<thead>
<tr>
<th>Flare ID</th>
<th>Flare Gas Recovery</th>
<th>Gas Treatment</th>
<th>Higher Heating Value Analyzer</th>
<th>Total Sulfur Analyzer</th>
<th>Flow Meter Upgrade</th>
<th>Purge/Pilot Flow Meter</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>1</td>
<td>1</td>
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<td><strong>23</strong></td>
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</table>

* Common flare gas recover and treatment system serving two flares
** Common flare gas recover and treatment system serving three flares
*** System consisting of two flares in cascade (common flow meter)

The cost for a flare recovery and gas treating system will be estimated based on data submitted to the AQMD by two local refineries as part of an application for permits to construct and operate, and data obtained from the Montana Department of Environmental Quality (DEQ) for a petroleum refinery located in Billings, Montana.
One local refinery installed a 10 million standard cubic feet per day (mmscfd) flare gas recovery system in 1993 for $10 million and a 48 mmscfd gas treating system for $23.2 million. The other local refinery installed in 2001 a flare gas recovery system with a capacity of 6 mmscfd for $9.2 million. The Billings, Montana refinery installed a flare gas recovery and gas treating system with a design capacity of 4 mmscfd for $7.7 million in 2003. Staff will determine the average normalized cost of the three examples studied to calculate the cost of flare gas recovery and gas treating systems needed to comply with the requirements and annual emission targets of PAR 1118.

Based on the first case study, installed in 1993, the cost for a flare recovery system and gas treating unit, normalized per one mmscfd, was $1.48 million ($1 million and $0.483 million respectively). In 2005 dollars, based on the Nelson Farrar Index published in the Oil and Gas Journal, the cost would be $1.43 million and $0.734 million respectively, for a total of $2.16 million per mmscfd.

Based on the second case study, installed in 2003, the normalized cost of the flare gas recovery system and corresponding gas treating system per one mmscfd was $1.93 million, of which $1.52 million was for flare gas recovery and $0.41 million was for the gas treating system. In 2005 dollars, based on the Nelson-Farrar Index, the cost would be $1.6 million and $0.48 million, respectively, or $2.08 million per mmscfd.

Based on the third case study, installed in 2001, the normalized cost for a flare gas recovery compressor per one mmscfd was $1.53 million. In 2005, this cost, based on the Nelson Farrar Index, would be $1.645 million. No gas treating system was installed in conjunction with this flare gas recovery system. However, based on the two other case studies, the cost of a flare gas recovery system is approximately 72 percent of the cost of a system consisting of both flare gas recovery and gas treating which is calculated as $0.635 million. Therefore, the total cost of a complete system would be $2.28 million per mmscfd.

Based on the above case studies, the average cost to install a flare gas recovery and treating system, based on three different system capacities of 4 mmscfd, 6, mmscfd and 10 mmscfd, is $2.17 million per mmscfd (2005 dollars).

Staff reviewed the Rule 1118 quarterly reports for the year 2003 and selected the quarters with the highest flows for the eight flares without flare gas recovery systems, then calculated the daily average flows for those quarters. API 521 guidelines recommends that the capacity of a flare gas recovery system be able to handle a wide variation in flow rates, and an Oil and Gas Journal article published on December 7, 1992, recommends the recovery capacity to be 2-3 times the average flow rate.

Based on this information, staff has estimated that for the first refinery, one system with a maximum capacity of 6 mmscfd, serving three flares, and a second system serving two flares with a maximum capacity of 4 mmscfd would be adequate. For the second refinery, staff projected that a system with a capacity of 3 mmscfd serving two flares would be adequate. For the third refinery staff estimated that a system with a capacity of 0.3 mmscfd for its flare would be adequate.

The costs to install the flare gas recovery and treating systems are estimated by using the average $2.17 million per mmscfd factor times the projected capacities needed by the refineries with no control on their emergency/general service flares to comply with PAR 1118. The costs are summarized in Table VI – 2:
Table VI – 2  
Total Installed Cost for Flare Gas Recovery and Gas Treatment

<table>
<thead>
<tr>
<th>Flare ID</th>
<th>Maximum Capacity (mmscfd)</th>
<th>Total Installed Cost ($)</th>
</tr>
</thead>
<tbody>
<tr>
<td>19, 20 and 25</td>
<td>6</td>
<td>13,020,000</td>
</tr>
<tr>
<td>9 and 16</td>
<td>4</td>
<td>8,680,000</td>
</tr>
<tr>
<td>4 and 7</td>
<td>3</td>
<td>6,510,000</td>
</tr>
<tr>
<td>11</td>
<td>0.3</td>
<td>651,000</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>13.3</strong></td>
<td><strong>$28,861,000</strong></td>
</tr>
</tbody>
</table>

The breakdown by flares of the projected installations, with the highest average daily flows and maximum capacities is shown in Table VI-3

Table VI – 3  
2003 Highest Quarterly Flows and Daily Average Flows

<table>
<thead>
<tr>
<th>Flare ID</th>
<th>Highest 2003 Quarterly Flow (mmscf)</th>
<th>Daily Average Flow (mmscfd)</th>
<th>Projected Treatment Capacity (mmscf)</th>
</tr>
</thead>
<tbody>
<tr>
<td>25</td>
<td>Common System</td>
<td>87.03</td>
<td>0.97</td>
</tr>
<tr>
<td>20</td>
<td>Common System</td>
<td>59.6</td>
<td>0.66</td>
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<td>1.13</td>
</tr>
<tr>
<td>4</td>
<td>Common System</td>
<td>49.43</td>
<td>0.55</td>
</tr>
<tr>
<td>7</td>
<td>Common System</td>
<td>48.53</td>
<td>0.54</td>
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<td>9.01</td>
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<tr>
<td><strong>Total</strong></td>
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<td><strong>4.93</strong></td>
<td><strong>4.93</strong></td>
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</tbody>
</table>

The cost of installing flow meters for purge gas and pilot gas is estimated by assuming that these devices would be connected to computerized control systems and therefore, will need data transmitters. An orifice plate flow meter and transmitter combination was quoted at $2,280 by a parts supplier, and labor is estimated at 10 hours at a rate of $35 per hour each. The total installed cost, assuming an additional 10 percent for software, instrumentation, and taxes is therefore estimated at $2,858 per flow meter and for 50 flow meters the total cost will be $142,900.
CHAPTER VI – COST AND COST EFFECTIVENESS

The proposed rule requires the flare gas flow meters to be upgraded with totalizing and low flow capability. This upgrade was quoted at $10,000 per flow meter by GE Panametrics, therefore the total cost for 23 flow meters will be $230,000.

The cost of the heat content analyzers was quoted at $70,775 each by Cosa Instruments. Assuming that the total installed cost, including a sample conditioning unit, shelter, piping, electrical, taxes, permitting and certification will be $150,000, the total installed cost for 23 analyzers is estimated at $3,450,000.

The cost of a total sulfur analyzer, including taxes, shipping, startup/commissioning was quoted by ThermoElectron at $79,308. The additional cost of installation for the total sulfur analyzer to the heat content analyzer and sample conditioning system is estimated at $5,000. Therefore the total installed cost is estimated at $84,308 each and $1,939,084 for 23 analyzers.

In order to calculate the cost effectiveness of the rule, the capital costs of the proposed amendment will need to be determined. It will be assumed that the flare gas recovery systems, gas treating systems and flow meters have an equipment life of 25 years, whereas the heat content analyzers and total sulfur analyzers have a 10 year equipment life. In order to have a common basis for equipment life to calculate the cost effectiveness, the cost of the analyzers will be referenced to a 25 year equipment life. For this purpose, it is assumed that during a 25 year period three sets of analyzers will have to be purchased. The cost of this expenditure is calculated below:

\[
C_{\text{analyzers}} = C_1 + C_2 + C_3
\]

1st Set Cost is at current cost:

\[
C_1 = $3,450,000 + $1,939,084 = $5,389,084
\]

The 2nd set is to be purchased after 10 years. Its cost in today’s dollars is calculated assuming a 4% real interest rate at ten years using the corresponding present worth factor of 0.6756 will be:

\[
C_2 = $5,389,084 \times 0.66756 = $3,640,865
\]

The 3rd set of analyzers is to be purchased after 20 years. The cost in today’s dollars, at 4% real interest rate at twenty years using the corresponding a present value factor of 0.4564 will be:

\[
C_3 = $5,389,084 \times 0.4564 = $2,459,578
\]

The total cost of the analyzers will therefore be, over a 25 year period:

\[
C_{\text{analyzers}} = C_1 + C_2 + C_3 = $11,489,527
\]

The flare gas recovery and gas treatment systems will require a permit to construct and operate from the AQMD. The permit application evaluation fee for one system is $7,233. As previously stated, the staff has determined that four control systems will need to be installed and operated to meet the annual sulfur dioxide performance targets in PAR 1118. Therefore, the permit application fees/cost to the refineries is $28,932.
A one-time CEMS certification fee is also required. The certification fee includes the initial application approval, approval of the test protocol and approval of the performance test results. The maximum fee is $7,693 for a monitoring system consisting of up to four components. The system required to comply with PAR 1118 consists of three (flow, higher heating value and total sulfur). The industry will install 23 higher heating value and total sulfur analyzer systems to comply with the monitoring requirements in PAR 1118. Therefore, the cost to certify the analyzer systems will be $176,939.

Under Scenario 1, the total estimated capital costs associated with the rule, based on the assumptions stated above, are summarized in Table VI-4.

Table VI – 4
Total Capital Costs Scenario 1

<table>
<thead>
<tr>
<th>Equipment</th>
<th>Cost ($)</th>
</tr>
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<tbody>
<tr>
<td>Flare Gas Recovery/Treatment Systems</td>
<td>28,861,000</td>
</tr>
<tr>
<td>Higher Heating Value/Total Sulfur Analyzers (Initial + 2 replacements)</td>
<td>11,489,527</td>
</tr>
<tr>
<td>Pilot/Purge Gas Meters</td>
<td>142,900</td>
</tr>
<tr>
<td>Flow Meter Upgrades</td>
<td>230,000</td>
</tr>
<tr>
<td>Permit Processing Fees</td>
<td>28,932</td>
</tr>
<tr>
<td>Analyzer (CEMS) Certification Fees</td>
<td>176,939</td>
</tr>
<tr>
<td><strong>Total Capital Cost</strong></td>
<td><strong>$40,929,298</strong></td>
</tr>
</tbody>
</table>

**Annual Costs**

The refineries will also incur annual costs associated with the newly installed equipment (parts and maintenance), surveys of pressure relief devices, conducting flow meter tests and Specific Cause Analyses.

Assuming that annual cost, such as for parts, maintenance, repairs, calibration gases, taxes, insurance and power represent 10 percent of the capital cost (including only the initial purchase of analyzers), the annual cost is estimated as $3,482,886.

Another annual cost will be for conducting surveys of the pressure relief devices connected to flares. These surveys can be conducted concurrently with the Rule 1173 quarterly inspections and it is estimated that on average an additional 200 hours per refinery and 100 hours for the hydrogen plant will be spent per year for this task. At $25 per hour, for seven refineries and a hydrogen plant, the annual cost will be $37,500.

Another annual cost will be for verifying the accuracy of flow meters. Flow verification costs were quoted at $1,500 per day for up to two flares. The annual cost for flow verification is estimated as $25,000 as shown below:
Table VI – 5
Annual Cost for Flow Meter Verification

<table>
<thead>
<tr>
<th>Facility</th>
<th>No. of Flares</th>
<th>Estimated Annual Cost ($)</th>
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<td>A</td>
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<tr>
<td>B</td>
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<td>1,500</td>
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<tr>
<td>C</td>
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</tr>
<tr>
<td>D</td>
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<td>F</td>
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<tr>
<td>G</td>
<td>6</td>
<td>4,500</td>
</tr>
<tr>
<td>H</td>
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<tr>
<td><strong>Total</strong></td>
<td><strong>27</strong></td>
<td><strong>$25,500</strong></td>
</tr>
</tbody>
</table>

The proposed rule will require refineries to conduct Specific Cause Analyses (SCA) for flaring events exceeding 500 pounds of sulfur dioxide, 100 pounds of VOC or 500,000 scf of vent gas. The investigation of flaring events exceeding 500 pounds of sulfur dioxide would not represent an additional cost since this is a requirement under federal law.

A review of the 2003 flaring events meeting these criteria stated in the previous paragraph found 980 flare events that had less than 500 pounds of sulfur dioxide emissions. However, these flaring events, representing 80 percent of the vent gas flow, included shutdowns and startups, turnaround activities or fuel gas balancing. The facilities subject to PAR 1118 are not required to submit an SCA for these categories of vent gas release under the proposed rule. Therefore, assuming that a corresponding 80 percent of these 980 events would not be required to submit an SCA, approximately 200 additional events would need to be investigated. The local refineries have estimated that the time needed to complete an SCA ranges from 40 to 200 hours. Based on this information, staff has estimated that a refinery would spend an average of 80 hours conducting SCA investigations, at an average rate of $50 per hour. The total annual cost of conducting an additional 200 SCA investigations that may be required as part of the proposed amended rule is therefore estimated at $800,000. The total annual costs associated under Scenario 1, as calculated above, are summarized in Table VI - 6:

Table VI -6
Total Annual Costs Scenario 1

<table>
<thead>
<tr>
<th>Item</th>
<th>Annual Cost ($)</th>
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<tr>
<td>Maintenance/Parts for Controls Equipment, Flow Meters, and Higher Heating Value and Total Sulfur Analyzers</td>
<td>3,482,886</td>
</tr>
<tr>
<td>Leak Surveys</td>
<td>37,500</td>
</tr>
<tr>
<td>Flow Meter Verification</td>
<td>25,500</td>
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<tr>
<td>Specific Cause Analyses</td>
<td>800,000</td>
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<tr>
<td>Control Equipment Annual Operating Fee</td>
<td>2,951</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>$4,348,836</strong></td>
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</table>
For scenario 2, the estimated capital costs will be identical to Scenario 1, except that it will not include the installation and operation of total sulfur analyzers but will include the addition of 23 automated sampling devices. A summary of the proposed rule requirements is shown in Table VI-7:

<table>
<thead>
<tr>
<th>Flare ID</th>
<th>Flare Gas Recovery</th>
<th>Gas Treating</th>
<th>HHV Analyzer</th>
<th>Automated Sampler</th>
<th>Flow Meter Upgrade</th>
<th>Purge/Pilot Flow Meter</th>
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<td>2</td>
</tr>
<tr>
<td>22</td>
<td>1</td>
<td>1</td>
<td>1</td>
<td>1</td>
<td>2</td>
<td></td>
</tr>
<tr>
<td>23</td>
<td>1</td>
<td>1</td>
<td>1</td>
<td>1</td>
<td>2</td>
<td></td>
</tr>
<tr>
<td>24</td>
<td>1</td>
<td>1</td>
<td>1</td>
<td>1</td>
<td>2</td>
<td></td>
</tr>
<tr>
<td>25</td>
<td>0.5*</td>
<td>0.5*</td>
<td>1</td>
<td>1</td>
<td>1</td>
<td>2</td>
</tr>
<tr>
<td>26</td>
<td>0.5*</td>
<td>0.5*</td>
<td>1</td>
<td>1</td>
<td>1</td>
<td>2</td>
</tr>
<tr>
<td>Total</td>
<td>4</td>
<td>4</td>
<td>23</td>
<td>23</td>
<td>23</td>
<td>50</td>
</tr>
</tbody>
</table>

* Common system serving two flares  
** System consisting of two flares in cascade (common flow meter)

The total installed cost of the automated sampling system is estimated at $5,000, and for 23 flares the cost will be $115,000.

As in Scenario 1, the cost of the 23 heat content analyzers will have to be referenced to a 25 year equipment life cycle; therefore it is assumed that 3 sets of analyzers have to be purchased during this period of time.

The cost for the initial set will be:

\[ C_1 = \$150,000 \times 23 = \$3,450,000 \]
After 10 years, in today’s dollars, the cost of the second set in today’s dollars will be:

\[ C_2 = 3,450,000 \times 0.6756 = 2,330,820 \]

After 20 years the cost of the third set of analyzers in today’s dollars will be:

\[ C_3 = 3,450,000 \times 0.4564 = 1,574,580 \]

The total cost of the analyzers, assuming a 25 years life, will be:

\[ C_{\text{analyzers}} = C_1 + C_2 + C_3 = 7,355,400 \]

The capital costs under Scenario 2 are summarized in Table VI-8:

<table>
<thead>
<tr>
<th>Equipment</th>
<th>Cost ($)</th>
</tr>
</thead>
<tbody>
<tr>
<td>FGRS/Amine Scrubbers</td>
<td>28,861,000</td>
</tr>
<tr>
<td>Heat Content Analyzers</td>
<td>7,355,400</td>
</tr>
<tr>
<td>Pilot/Purge Gas Meter</td>
<td>142,900</td>
</tr>
<tr>
<td>Flow Meter Upgrade</td>
<td>230,000</td>
</tr>
<tr>
<td>Automated Sampling System</td>
<td>115,000</td>
</tr>
<tr>
<td>Permit Processing Fees</td>
<td>28,932</td>
</tr>
<tr>
<td>Analyzer (CEMS) Certification Fees</td>
<td>176,939</td>
</tr>
<tr>
<td><strong>Total Capital Cost</strong></td>
<td><strong>36,910,171</strong></td>
</tr>
</tbody>
</table>

Under Scenario 2, all refineries will be required to take six additional daily samples for total sulfur per flare during the week, incurring additional annual costs. Assuming that the cost of processing a sample will average $350, the annual cost of sampling will be:

\[ \text{Annual Sampling Cost} = 23 \text{ flares} \times 6 \text{ samples/wk} \times 52 \text{ wks} \times $350/\text{sample} = 2,511,600 \]

The cost of maintenance, parts, power, insurance and taxes for equipment is assumed to be 10 percent of the total capital cost (including only the initial purchase of analyzers). Therefore, the total annual cost for the equipment and analyzers will be $3,300,477.

A summary of the annual costs under Scenario 2 is presented in Table VI – 9.
### Recovered Vent Gas - Cost Savings

The flare gas recovery systems will recover vent gases that otherwise would be combusted in the flares. The recovered gas, after treatment, can be used as fuel gas or process feed, thus reducing operating costs for the refineries. Additional savings are realized by using less steam for the flare operations and extended flare tip life, minimizing repair costs; for this calculation, only the payback value of the recovered gas to be used as fuel gas or process feed is considered. This would represent annual savings that can lower the annual costs.

The following assumptions will be made:

- The annual average recovered gas volume is \(3.2852,337\ \text{mmscf}\) (see Chapter V – Emission Reductions)
- On average, only 60 percent of the recovered gas volume is valuable product (based on review of recovered gas samples from a local refinery)
- The value of recovered gas is estimated at \$2\ per \text{mmBtu}\ (\text{www.johnzink.com}\text{ – Flare Gas Recovery payback analysis})
- The average heat content of the recovered gas is 1,000 Btu/scf

\[
\text{Annual Savings} = 3.2852,337 \times 10^6 \text{ scf} \times 0.6 \times 1,000 \text{ Btu/scf} \times \frac{\$2}{10^6} \text{ Btu} = 3,909,600,280,400
\]

As emissions will decrease, the refineries will pay reduced annual emission fees to the AQMD, reducing their annual costs. Table VI – 10 lists the estimated annual emission fees savings by pollutant and the total savings for the industry.
Table VI – 10
Estimated Annual Emission Fees Savings

<table>
<thead>
<tr>
<th>Pollutant</th>
<th>Fees* ($/ton)</th>
<th>Projected Reduction (tons)</th>
<th>Estimated Savings ($)</th>
</tr>
</thead>
<tbody>
<tr>
<td>ROG</td>
<td>944.16</td>
<td>33</td>
<td>31,157</td>
</tr>
<tr>
<td>NOx</td>
<td>543.73</td>
<td>47</td>
<td>25,555</td>
</tr>
<tr>
<td>CO</td>
<td>4.64</td>
<td>214</td>
<td>993</td>
</tr>
<tr>
<td>PM10</td>
<td>720.72</td>
<td>15</td>
<td>10,811</td>
</tr>
<tr>
<td>SO2</td>
<td>653.98</td>
<td>356</td>
<td>232,817</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td></td>
<td></td>
<td><strong>$290,439</strong></td>
</tr>
</tbody>
</table>

*Rule 301 – Table III-Emission Fees (June 3, 2005)

The total annual costs will then be:

For Scenario 1:

Total Annual Cost = $4,285,398 – $3,909,600 – $290,439 = $85,359

For Scenario 2:

Total Annual Cost = $6,614,597 – $3,909,600 – $290,439 = $2,314,551

B. COST-EFFECTIVENESS

In order to calculate the cost effectiveness of the proposed amendment, the present value of the capital cost and operating cost during the useful life of the control equipment and/or program must be calculated, using the following formula:

\[ PV = C + A \times PVF \]

where:

- \( PV \) = Present Value to implement the proposed new rule requirements
- \( C \) = Capital costs to implement proposed new rule requirements
- \( A \) = Annual costs to implement proposed new rule requirements
- \( PVF \) = Present Value Factor, Equal Series
Cost Effectiveness – SOx Emission Reductions Only

Scenario 1:

\[ C = \$40,929,298 \]
\[ A = \$85,359,1,190,559 \]
\[ PV_1 = \$40,929,298 + \$85,359,1,190,559 \times 15.62 = \$42,262,606,59,525,830 \]

The cost effectiveness is calculated with the discount cash flow (DCF) method:

\[ CE_1 = \frac{PV_1}{(ER \times EL)} \]

where:

\[ CE_1 = \text{Cost Effectiveness for Scenario 1} \]
\[ ER = \text{Emission Reduction for SO}_2, \text{ 431 tons per year} \]
\[ EL = \text{Equipment life, 25 years} \]

\[ CE_1 = \frac{\$42,262,606,59,525,830}{(431 \text{ tons} \times 25)} = \$3,9225,524 \text{ per ton of SO}_2 \text{ reduced} \]

Scenario 2

\[ C = \$36,910,171 \]
\[ A = \$2,414,554,3,583,189 \]
\[ PV_2 = \$36,910,171 + \$2,414,554,3,583,189 \times 15.62 = \$74,625,458,92,879,583 \]
\[ CE_2 = \frac{\$74,625,458,92,879,583}{(431 \text{ tons} \times 25)} = \$6,9268,620 \text{ per ton SO}_2 \text{ reduced} \]

Therefore, the cost effectiveness for this proposed amendment is estimated to be between \$3,9225,524 and \$6,9268,620 per ton of SOx reduced.

Cost Effectiveness – Total Emissions Reductions (Excluding CO)

If reductions in the other pollutants were to be considered, the cost effectiveness would be:

\[ CE = \frac{PV}{(TER \times EL)} \]
where:

\[
\begin{align*}
PV & = \text{Present Value to implement the proposed new rule requirements} \\
TER & = \text{Total emission reduction for the other criteria pollutants less CO, tons per year} \\
EL & = \text{Equipment life, 25 years}
\end{align*}
\]

From Table V – 2:

\[
TER = 431 \text{ tons} + 47 \text{ tons} + 33 \text{ tons} + 15 \text{ tons} = 526 \text{ tons}
\]

**Scenario 1**

\[
CE1 = \frac{40,929,298,525,830}{(526 \times 25)} = \$3,1124,527 \text{ per ton of pollutant reduced}
\]

**Scenario 2**

\[
CE2 = \frac{74,625,459,287,9,583}{(526 \times 25)} = \$5,6757,063 \text{ per ton of pollutant reduced}
\]

Therefore, if reductions for the other criteria pollutants, less CO, are included in calculations, the cost effectiveness of the proposed amendments ranges between $3,1124,527 and $5,6757,063 per ton of pollutant reduced, excluding CO.

**C. INCREMENTAL COST-EFFECTIVENESS**

Staff is required under state law to determine an incremental cost effectiveness of the most stringent control scenario. Staff believes that the most stringent control scenario would require petroleum refineries to control all vent gases excluding off specification gas and vent gases resulting from emergencies.

An analysis of the reported flare gas flow and emissions data for years 2002, 2003, and 2004 and vent gas recovery and treatment capacity associated with flares is summarized as follows:

Flare gas recovery and treatment system capacity

| Current: | 51 mmscfd |
| Future implementing PAR1118 requirements: | 64.5 mmscfd |
| Additional capacity to treat maximum daily flow recorded: | 119 mmscfd |
| (excluding off spec gas and emergencies) |

**PAR 1118 - 2012 Emissions**

| SO₂ performance target: | 0.50 TPD |
| Total emissions, less SO₂ and CO: | 0.24 TPD |
| Reported non-emergency, SO₂: | 94% (based on 2002 and 2003 data) |
Capital cost of the additional flare gas recovery and treatment system capacity

Estimate cost of system based on a previously determined cost of $2.17 million per million standard cubic feet per day treatment capacity (mmscfd)

$2.17 \text{ million/mmscfd} \times 119 \text{ mmscfd} = $258,227,362

Annual cost is estimated to be 10 percent of the capital cost

$258,227,362 \times 0.10 = $25,822,362

SO\textsubscript{2} Emission Reductions Only

\[
\begin{align*}
\text{PV} &= $258,227,362 + $25,822,362 \times 15.62 = $661,578,503 \\
\text{CE} &= \frac{\text{PV}}{(\text{Incremental ER} \times \text{EL})} \\
\text{CE} &= \frac{$661,578,503}{[0.5 \text{ tons/day} \times 0.93 \times 25 \text{ yrs} \times 365 \text{ days/yr}]} \\
&= $155,918 \text{ per ton of SO}_2 \text{ reduced}
\end{align*}
\]

Total Emissions Reductions, Less CO

\[
\begin{align*}
\text{PV} &= $258,227,362 + $25,822,362 \times 15.62 = $661,578,503 \\
\text{CE} &= \frac{$661,578,503}{[(0.5 \text{ ton/day} \times 0.93 + 0.24 \text{ ton/day} \times 0.68) \times 25 \text{ yrs} \times 365 \text{ days}]} \\
&= $115,412 \text{ per ton of air contaminant reduced}
\end{align*}
\]

Therefore, the incremental cost effectiveness for this proposed amendment is estimated to be between $115,412 and $155,918 per ton of air contaminant reduced.
CHAPTER VII

COMPARATIVE ANALYSIS
<table>
<thead>
<tr>
<th>PAR 1118</th>
<th>U.S. EPA 40CFR 60.18 and Subpart J</th>
</tr>
</thead>
</table>

**Applicability**
- Flares at refineries, sulfur recovery plants and hydrogen production plants
- Flares built or modified after June 11, 1973, subject to 40CFR 60 Subpart J
- Flares controlling vents from piping components subject to 40CFR 60 Subpart GGG, from storage tanks subject to 40CFR 60 Subpart K, or from wastewater systems subject to 40CFR 60 Subpart QQQ

**Requirements**
- Flares to be operated with no visible emissions
- Flares to be operated with a pilot flame present at all times
- Annual acoustical or thermal surveys of PRD’s directly connected to flares
- Specific Cause Analysis of flare events exceeding:
  - 500 lbs SO₂
  - 100 lbs VOC
  - 500,000 scf vent gas combusted
- Cause of flare events where at least 5,000 scf of vent gas are combusted
- Effective September 1, 2006, submit the following information:
  - Technical specifications on flare systems including an audit of gas recovery and treating system capacity and storage capacity for excess vent gases
  - A description of equipment installed and procedures implemented within the last 5 years to minimize flaring
  - A description of equipment to be installed or procedures to be implemented to minimize or eliminate flaring
- Effective January 1, 2007, operate flares in such a manner as to minimize flaring and only combust vent gas during emergencies, shutdowns, startups, turnarounds or essential operational needs
- Flares to be operated with no visible emissions
- Flares to be operated with a pilot flame present at all times
- Air or steam assisted flares shall only combust gases with a heat content of 300 BTU/scf or more
- The exit velocity of the vent gas is limited by the net heating value of the vent gas
- Flares shall not be used to combust gases containing more than 0.1 gr/dscf (160 ppm) H₂S, averaged over 3 hours
Effective January 1, 2009, combustion in flares of gases with hydrogen sulfide concentration exceeding 160 ppm, averaged over 3 hours, is prohibited, unless in an emergency, shutdown, startup or PRD leakage.

### Performance Targets
- Specific annual performance targets for subject facilities based on their crude throughput and processing capacity
- Mitigation fees assessed for exceedance of performance targets
- N/A

### Flare Minimization Plans
- Triggered by exceedance of performance target, or
- To include policies and procedures and process and equipment upgrades implemented to prevent future exceedances
- Subject to public review and comment
- N/A

### Monitoring and Recording
- Until July 1, 2007, continuous monitoring of vent gas flow, sample daily and during sampling events for vent gas higher heat content and total sulfur as SO₂ or install continuous or semi-continuous analyzers
- After July 1, 2007, continuous monitoring of vent gas flow, higher heat content and semi-continuously for total sulfur as SO₂
- The presence of pilot flames monitored with thermocouples or equivalent devices
- Effective July 1, 2006, video monitors with date and time stamp must be used to determine visible emissions
- Effective January 1, 2007:
  - automated sampling system required for vent gas sampling
- The presence of pilot flames monitored with thermocouples or equivalent devices
## COMPARATIVE ANALYSIS FINAL STAFF REPORT

<table>
<thead>
<tr>
<th>PAR 1118</th>
<th>U.S. EPA 40CFR 60.18 and Subpart J</th>
</tr>
</thead>
<tbody>
<tr>
<td>o Pilot and purge gas flow must be monitored</td>
<td></td>
</tr>
<tr>
<td><strong>Recordkeeping</strong></td>
<td></td>
</tr>
<tr>
<td>− Video monitoring records to be kept for 90 days</td>
<td>− Records to be kept at least two years</td>
</tr>
<tr>
<td>− Other records to be kept for five years</td>
<td>− Records to be kept at least five years for Title V facilities</td>
</tr>
<tr>
<td><strong>Notification and Reporting</strong></td>
<td></td>
</tr>
<tr>
<td>− 24 hour telephone service provided for public inquiries on flare events</td>
<td>− Semiannual reports</td>
</tr>
<tr>
<td>− 1 hour notification of events exceeding:</td>
<td>− Notifications required by 40CFR Subchapter 355 Emergency Planning and Community Right to Know Act (EPCRA) pertaining to reportable air releases</td>
</tr>
<tr>
<td>o 500 lbs SO$_2$</td>
<td></td>
</tr>
<tr>
<td>o 100 lbs VOC</td>
<td></td>
</tr>
<tr>
<td>o 500,000 scf vent gas combusted</td>
<td></td>
</tr>
<tr>
<td>− 24 hour notification of planned events exceeding:</td>
<td></td>
</tr>
<tr>
<td>o 500 lbs SO$_2$</td>
<td></td>
</tr>
<tr>
<td>o 100 lbs VOC</td>
<td></td>
</tr>
<tr>
<td>o 500,000 scf vent gas combusted</td>
<td></td>
</tr>
<tr>
<td>− Submittal of Specific Cause Analysis of qualifying flare events within 30 days or 60 days upon request</td>
<td></td>
</tr>
<tr>
<td>− Quarterly reports in electronic format certified for accuracy by responsible facility official, to include:</td>
<td></td>
</tr>
<tr>
<td>o Daily and quarterly flare emissions</td>
<td></td>
</tr>
<tr>
<td>o Causes of flare events</td>
<td></td>
</tr>
<tr>
<td>o Records of annual PRD</td>
<td></td>
</tr>
<tr>
<td>o Monitoring system down times</td>
<td></td>
</tr>
<tr>
<td>− Copies of notifications required by 40CFR 355 pertaining to reportable air releases</td>
<td></td>
</tr>
<tr>
<td><strong>Testing and Monitoring</strong></td>
<td></td>
</tr>
<tr>
<td>PAR 1118</td>
<td>U.S. EPA 40CFR 60.18 and Subpart J</td>
</tr>
<tr>
<td>---------------------</td>
<td>-----------------------------</td>
</tr>
<tr>
<td>Vent Gas higher heating value determined:</td>
<td>Net heating value of the vent gas determined with ASTM Method D2382-88 or D 4809-95</td>
</tr>
<tr>
<td>- By ASTM Method D2382-88, ASTM Method D3588-91 or ASTM Method D4891-89</td>
<td>-</td>
</tr>
<tr>
<td>- Effective July 1, 2007 with continuous analyzer</td>
<td></td>
</tr>
<tr>
<td>Vent Gas total sulfur expressed as SO(_2) determined:</td>
<td>-</td>
</tr>
<tr>
<td>- By ASTM Method D5504-01 or District Method 307-91</td>
<td></td>
</tr>
<tr>
<td>- Effective July 1, 2007, with a semi-continuous analyzer</td>
<td>-</td>
</tr>
<tr>
<td>Flow monitored with a continuous flow measuring device requiring annual accuracy verification</td>
<td></td>
</tr>
</tbody>
</table>

- **Exemptions**

- Sampling not required if:
  - There is a catastrophic event, or
  - Safety of sampling personnel is at issue
- Emissions from flaring events due to force majeure or circumstances beyond the operators’ control do not count towards annual performance targets

- Emergency or upset vent gas and relief valve leakage due to malfunctions may exceed a H\(_2\)S concentration exceeding 160 ppm

Facilities subject to PAR 1118 are also subject to the following AQMD rules:

- Rule 401 – Visible Emissions
- Rule 402 – Nuisance
- Rule 431.1 – Sulfur Content of Gaseous Fuels
CHAPTER VIII

DRAFT FINDINGS
Health and Safety Code Section 40727 requires that prior to adopting, amending or repealing a rule or regulation, the AQMD Governing Board shall make findings of necessity, authority, clarity, consistency, non-duplication, and reference based on relevant information presented at the hearing. The draft findings are as follows:

**Necessity** - The AQMD Governing Board has determined that a need exists to amend Rule 1118 – Emissions from Refinery Flares, to make current emission reductions permanent and enforceable, and to achieve emission reductions to meet the federal and state ambient air quality standard for PM 10 and PM 2.5 and to clarify rule language.

**Authority** - The AQMD Governing Board obtains its authority to adopt, amend, or repeal rules and regulations from Health and Safety Code Sections 39002, 40000, 40001, 40440, 40702, and 41508.

**Clarity** - The AQMD Governing Board has determined that the proposed amendments to Rule 1118 - Emissions from Refinery Flares, are written and displayed so that the meaning can be easily understood by persons directly affected by them.

**Consistency** - The AQMD Governing Board has determined that Proposed Amended Rule 1118 - Emissions from Refinery Flares, is in harmony with, and not in conflict with or contradictory to, existing statutes, court decisions, federal or state regulations.

**Non-Duplication** - The AQMD Governing Board has determined that the proposed amendments to Rule 1118 - Emissions from Refinery Flares, do not impose the same requirement as any existing state or federal regulation, and the proposed amendments are necessary and proper to execute the powers and duties granted to, and imposed upon, the AQMD.

**Reference** - In adopting these amendments, the AQMD Governing Board references the following statutes which the AQMD hereby implements, interprets or makes specific: Health and Safety Code Sections 40001 (rules to achieve ambient air quality standards), 40440(a) (rules to carry out the Air Quality Management Plan), and 40440(c) (cost-effectiveness), 40725 through 40728.
CHAPTER IX

COMMENTS AND RESPONSES
ARB

Comment 1: Although the phrase “Flare Management (Minimization) Plan” is a central concept of the PAR 1118, the phrase is not included in the list of definitions. Staff recommends its inclusion.

Response 1: PAR 1118 has been revised using the phrase “Flare Minimization Plan” (FMP). The latest proposal put greater emphasis on the minimizing flare events and emissions through the annual performance targets, which are significantly lower than previously presented at the June 29, 2005 Public Workshop. The latest proposal only requires an FMP from those refineries that exceed the annual performance targets. The required elements to be submitted as part of the FMP are listed under paragraph (e)(1), which effectively defines what an FMP is.

Comment 2: Staff recommends that the definition of “Essential Operational Needs” be clarified so as to be limited to only those events clearly identified in an approved “Flare Management (Minimization) Plan”.

Response 2: PAR 1118 has been revised to include a definition of Essential Operational Needs.

Comment 3: PAR 1118 ought to explicitly require that any pressure relief devices found to be defective or leaking be expeditiously repaired.

Response 3: Pressure relief devices (PRDs), in particular PRDs that are connected directly to the flare gas header, can not be repaired without shutting down the process unit which they serve. Therefore, refineries typically repair defective or leaking PRDs during the process unit turnaround. To facilitate expeditious repair, PAR 1118 requires the refineries to conduct the PRD survey within 90 days prior to a turnaround.

Comment 4: The district should include a mechanism to allow for public comment on the proposed Flare Management (Minimization) Plan [FMP] prior to each FMPs approval. The lack of specific quantifiable standards for an FMP to attain approval, as well as the fact that each FMP will be unique, make it imperative that a forum for public comment is included to provide all interested parties with the opportunity to provide critical input.

Response 4: PAR 1118 has been revised to incorporate a provision that requires a 60 day public comment period for each Flare Minimization Plan (FMP) that has been reviewed and recommended for approval by the AQMD.
Comment 5: Flare Management (Minimization) Plans should be required to be updated on an annual basis to incorporate improvements in flare management. Additionally, the district ought to include in the rule amendment a future commitment to evaluating Rule 1118 and making future recommendations to improve its effectiveness.

Response 5: PAR 1118 has been revised to require submittal of a FMP or revised FMP whenever a refinery exceeds the annual SO$_2$ performance target. Staff will continue to analyze data that will be submitted to the AQMD as required by PAR 1118. As with other rules, staff will also assess the effectiveness of PAR 1118 to determine if future technologically feasible and cost effective amendments are necessary to achieve and maintain ambient air quality standards.

Comment 6: In the preliminary draft staff report, the emission reduction calculation for sulfur compounds was made using a different methodology than was used to calculate the reduction of other criteria pollutants. This discrepancy in methods should be corrected.

Response 6: The emission reduction for total sulfur, expressed as sulfur dioxide is based on the performance target in the rule, whereas the concurrent emission reductions for other combustion pollutants was based on the assumption that the flare vent gas flow will be reduced with the installation of additional flare gas recovery and treatment system(s).

Minimization

Comment 7: The language in section (c) Requirements (2)(A) is extremely ambiguous. The lack of specificity in the language, “take steps to minimize emissions during such events”, could provide a loophole for facilities operating flares, and could lead to disputes over enforcement.

Response 7: PAR 1118 has been revised to include the requirement to minimize all flaring.

Public Input and Involvement

Comment 8: The district should hold a public hearing and provide the opportunity for public comment prior to approving any FMP.

Response 8: PAR 1118 has been revised to incorporate a provision that requires a 60 day public comment period for each flare minimization plan (FMP) that has been reviewed and recommended for approval by the AQMD.
Comment 9: The public should be provided with quarterly flare reports online. The public has a right to emissions information and providing it online will allow the public to bypass the often long delays inherent in the public records request process.

Response 9: *Staff will post a summary of the quarterly flare emission reports on the AQMD web site.*

Mitigation Fees

Comment 10: Individual facility mitigation fees are preferable to mitigation fees based on industry-wide thresholds. Requiring mitigation fees to be paid based upon an industry-wide threshold is not an equitable arrangement for individual facilities, nor is it in keeping with environmental justice principles.

Response 10: *PAR 1118 has been revised to establish facility-specific performance targets and mitigation fees will only be assessed for emissions exceeding the annual SO\(_2\) performance target.*

Comment 11: The PAR 1118 indicates that a mitigation fee of $25,000 per ton will be charged for all emissions. The applicability of that mitigation fee should be changed so that it pertains only to those emissions above the prescribed target.

Response 11: *PAR 1118 has been revised such that mitigation fees will only be assessed for emissions exceeding the annual SO\(_2\) performance target.*

Comment 12: The cost of $25,000 per ton is excessive given previous fees of $10,000 per ton or the RECLAIM backstop ceiling of $15,000 per ton. Furthermore, these mitigation fees are being charged on top of an existing fee (AER). The rule should offer the ability for a facility to propose a local community project for which their mitigation fee payments could be used.

Response 12: *PAR 1118 has been revised such that any refinery exceeding the specified performance target in any calendar year, it will have to pay a mitigation fee of $25,000, $50,000 or $100,000 per each ton of sulfur dioxide over the limit, depending on whether excess emissions are no more than ten percent, greater than ten percent but no more than twenty percent or greater than twenty percent of the applicable performance target, respectively. The mitigation fee is capped at $4,000,000 dollars in any year that the performance target is exceeded.*

*Any mitigation fees paid would be used to implement emission reduction projects in the area impacted by the excess emissions. The amount of the*
mitigation fee is based upon the current and future expected costs of vent gas recovery and treatment equipment needed to mitigate the exceedance of the final annual performance target. It is expected that refineries will implement the procedures and install the equipment necessary to achieve compliance with the performance targets.

Comment 13: There should be no exemptions from mitigation fee payments. High emissions can still result even from facilities that are in compliance with the requirements to be exempted from paying mitigation fees.

Response 13: PAR 1118 has been revised such that no facility is exempt from paying mitigation fees for emissions exceeding the annual SO\textsubscript{2} performance targets.

Comment 14: In order to be exempt from mitigation fee payments, a facility must meet emissions standards of 0.25 tons or less of SOx per 1 million barrels of crude throughput. This standard is too low and based on a one-time best achieved emissions level by a refinery.

Response 14: Under the revised staff proposal, this compliance option is no longer necessary and, therefore, staff has removed this compliance option from PAR 1118.

Comment 15: The rationale behind calculating the emission level of SOx as a two-year average needs to be explained.

Response 15: Staff has removed this compliance option from PAR 1118. However, for clarification, calculating emissions for compliance purposes using a two-year average was based on the fact that the frequency of flare events (and emissions) do not constant; they can vary from year to year. An average would smooth out any anomalies.

Flare Minimization Plan

Comment 16: The Flare Management Plan requirement could be a stand alone rule. The requirement simply duplicates the emission reductions already imposed by limitations on causes of flaring, the performance goals, and the 160 ppm vent gas H\textsubscript{2}S limit.

Response 16: PAR 1118 has been revised to only require a flare minimization plan (FMP) from refineries that exceed the annual SO\textsubscript{2} performance targets. The FMP requirement is a tool to ensure refineries that take appropriate measures to stay below the annual performance targets. Therefore, staff believes the FMP needs to be a part of PAR 1118.
Comment 17: The requirement to provide in the FMP application a list of all valves, components, or any equipment at any process units venting directly to the flares is extremely punitive and burdensome and serves no apparent useful purpose.

Response 17: PAR 1118 has been revised to only require P&IDs for each flare system in the FMP. Secondly, staff believes refineries will take the necessary steps, including the installation or modification of vapor recovery and gas treatment system(s) to ensure compliance with the annual performance standards. Therefore, staff believe that submittal of an FMP (with required data and information) is not likely.

Comment 18: An explanation of policies and procedures to minimize flaring emissions during emergencies, shutdown and startup of each process unit should not be required in the FMP application. Since many policies and procedures are not unit-specific and instead have broad applicability, refineries ought to be able to respond to this requirement in a form and manner appropriate to their situation.

Response 18: PAR 1118 has been revised to require an FMP only from refineries that exceed the annual SO2 performance targets. Also, the information required under a FMP submittal has been streamlined to only include refinery policy and procedures to be used and vapor recovery and gas treatment capacity that will be installed to minimize flaring.

Comment 19: The district should provide more specific startup/shutdown requirements in order to provide better direction to refineries which will in turn help ensure compliance.

Response 19: Because of the differences in the way refineries in the Basin are designed and operated and the associated complexities of these operations, as well as safety implications, staff believes that it is best to leave the election of specific procedures relative to shutdown and startup to the refinery operators. It is more appropriate, as PAR 1118 does, to establish a regulatory framework that requires refineries to minimize emissions.

Comment 20: It is not practical to include in a FMP an estimate of the quantity of vent gas emitted during each occurrence, the duration of each occurrence, the number of occurrences each quarter, and maximum total volume of vent gas being routed to the flares each year is an impractical request. There is concern over the potential negative ramifications for refineries who cannot accurately predict the various aspects related to their future occurrences.
Response 20: PAR 1118 has been revised to require from refineries that exceed the annual \( SO_2 \) performance target to include in their FMP application the policies and procedures as well as gas recovery and treatment systems that will be utilized to minimize flaring and related emissions.

Comment 21: There should be no exemption for developing an FMP. Instead, both the strict emissions targets of .25 tons of SO\(_x\) per 1 million barrels of crude processed and an FMP should be required of all refineries.

Response 21: The latest proposal of PAR 1118 puts greater emphasis on minimizing flare events and emissions through the annual performance targets, which are significantly lower than previously presented at the June 29, 2005 Public Workshop. The 2010 annual \( SO_2 \) performance target of 0.7 tons per million barrels of crude oil processed is much lower than the 2.1 tons per year target stated in the 2003 AQMP. Staff believes the proposed performance targets are real, quantifiable, enforceable, and permanent (with the requirement of a mitigation fee for annual exceedances) and are technologically feasible and cost effective. A FMP will only be required from refineries that exceed the annual \( SO_2 \) performance targets.

Comment 22: The level of emissions .25 tons of SO\(_x\) per 1 million barrels of crude processed is too low to be practicable for refineries to meet. At such a low level, reducing emissions is no longer a viable alternative to submitting an FMP. This emission limit of 0.25 tons/MMBbl is based on the very lowest emissions data from two refineries. The district should take into consideration that even at the refineries that did achieve the aforementioned limit, there will always be year to year fluctuations in emissions.

Response 22: The version of PAR 1118 presented at the Public Workshop provided refineries a compliance option to request a permit limit of 0.25 ton of SO\(_x\) per 1 million barrels of crude processed; refineries accepting the permit limit would not be required to submit a FMP. Based on public comment and discussion with the Refinery Working Group, PAR 1118 has been revised to remove this compliance option. PAR 1118 was revised to now require refineries to meet declining performance targets over time and, beginning calendar year, 2010\(_2\), to emit no more than 0.75 ton \( SO_2 \) per million barrels of crude oil processed per year.

Specific (Root) Cause Analysis

Comment 23: The 100,000 scf of vent gas or 500 lbs of sulfur dioxide emissions as a threshold for root cause analysis is too low. 500,000scf or 1000 lbs of sulfur dioxide emissions is suggested as a more practical threshold level.
Response 23: PAR 1118 has been revised to now require a Specific Cause Analysis (SCA) when flare emissions or flow rate exceed any one of the following: 100 lbs of VOC; 500 lbs of SO\textsubscript{x} emitted or flaring of 500,000 standard cubic feet of vent gas. Under federal requirements, refineries are required to analyze and report SO\textsubscript{x} emissions exceeding 500 pounds per release.

Essential Operational Needs

Comment 24: It is impossible for an operator to foresee in detail all possible essential operational needs. Therefore, the rule should provide pre-defined EON categories with the provision that if a facility encounters a new scenario, the facility has the prerogative to analyze the event, determine if it is and EON and then submit it to AQMD for approval.

Response 24: Staff has revised the definition of Essential Operational Need in PAR 1118 to now list specific operational or maintenance related activities where due to the quality or quantity, the vent gas cannot be reasonably recovered, treated, used or delivered for sale with existing equipment.

Comment 25: The current definition of Essential Operational Needs disqualifies many scenarios that a refinery could actually identify as an EON. The district, in deciding whether a scenario qualifies as an EON ought to examine not just the technical feasibility of a measure, but also the practicality, cost, and cost-effectiveness. The definition of EON should include such scenarios as fuel gas system imbalances, PRV leakage, and adding fuel gas to vent gas to support its combustion.

Response 25: In developing standards and requirements, staff conducts technological feasibility and cost effectiveness analyses. The definition Essential Operational Needs in PAR 1118 has been revised to include such scenarios as fuel gas system imbalances, PRV leakage, and venting clean service streams to a clean service flare or a general service flare, and adding fuel gas to vent gas to support combustion.

Visible Emissions

Comment 26: PAR 1118s provision to require a visual emissions evaluation within five minutes of observing visual emissions on the video monitor is impractical at best, and at worst, dangerous. During emergencies the focus of trained personnel should be on responding to the emergency, not on conducting a visual emissions evaluation.

Response 26: Staff agrees with the recommendation. PAR 1118 has been revised to require video monitoring with a date and time stamp to determine and record visible emissions from refinery flares.
Comment 27: The requirement to visually monitor is vague and could imply around the clock monitoring. Such a requirement would mean that a facility could be out of compliance if a video monitor appeared to be “unattended” by refinery personnel.

Response 27: PAR 1118 has been revised to remove that requirement that a refinery visually monitor visible emissions from flares. See Response 26.

Comment 28: The requirement to operate all flares in a smokeless manner constitutes double jeopardy, as visible emissions are already regulated under Rule 401.

Response 28: Staff disagrees. Although both PAR 1118 and Rule 401 address visible emissions, they are different standards with different requirements and measurement methods. PAR 1118 requires that flares be operated in a smokeless manner, which is defined as no visible emissions except for periods not to exceed a total of five minutes during two consecutive hours, based on USEPA Method 22. Rule 401 limits the visible emissions into the atmosphere from any single source of air contaminant for a period or periods not to exceed more than three minutes in any one hour to as dark or darker in shade as that designated No. 1 on the Ringelmann Chart or an equivalent opacity, based on USEPA Method 9. Therefore this does not constitute double jeopardy.

Comment 29: The requirement to operate all flares in a manner with no visible emissions ignores the basic flare design principles such as smokeless capacity vs. ultimate capacity.

Response 29: Staff understands that vent gas flow exceeding the smokeless capacity may result in visible emissions. PAR 1118 allows visible emissions for periods not to exceed a total of five minutes during two consecutive hours flare will cause visible emissions. Any visible emissions due to exceedances of the flares smokeless capacity are typically due to emergencies and breakdowns. Such visible emissions caused by the incident would be covered by Rule 430 – Breakdown.

Comment 30: Some threshold Ringelmann number must be specified for visible emissions. If it is not, the smallest wisps of smoke could trigger an NOV or the smallest wisps of smoke could require a “reader” to go out into the field and conduct a visible emissions evaluation.

Response 30: PAR 1118 allows visible emissions for periods not to exceed a total of five minutes during two consecutive hours. Staff has deleted the requirement that a certified “smoke” reader monitor visible emissions. See Responses 27 and 30.
Comment 31: The requirement for a PRD survey to be conducted within 90 days prior to a scheduled turnaround is not adequate for turnaround planning purposes. Instead of specifying timing, the rule should specify that the scheduling of any PRD survey should be consistent with the turnaround planning timetable.

Response 31: Staff disagrees. Maintenance, repair or replacement of defective PRDs is necessary to minimize flare emissions and often can only be corrected during a turnaround. It is now common practice to conduct unit turnarounds every five years. Conducting the PRD survey too far in advance of a scheduled turnaround may not provide the refinery with the knowledge that a PRD is now leaking and in need of corrective action. Staff believes that conducting the PRD survey within 90 days of the turnaround provides the refinery with sufficient time to adjust their turnaround timetable and gives the surrounding community a reasonable expectation that they will not have to experience flare emissions from leaking PRDs for the next five years waiting for the next scheduled turnaround.

Clean Service Flares

Comment 32: Clean service flares should be exempted from the various requirements of PAR 1118. Their emissions are insignificant and they are already regulated to a certain extent under current Rule 1118.

Response 32: Staff disagrees. All emissions should be considered in determining whether the facility meets its performance targets. In recognition, however, clean service flares may have a more consistent and typically lower SO2 concentration compared to other flares and are exempt from the daily sampling requirements.

H2S Limits

Comment 33: The 160ppm H2S limit for flaring is duplicative of limitations on causes of flaring, the requirements for FMPs, and the performance goals. Furthermore, this limit is an attempt to apply the EPA Subpart J (NSPS) limit to all flaring, an unnecessary rule element as industry has already achieved the emissions reductions contemplated by the AQMP measure. Additionally, Subpart J specifies a 3 hour rolling average, while PAR 1118 specifies no time limit. The AQMD has not demonstrated the feasibility of universal compliance with the 160ppm H2S limit NSPS-based requirement that is not currently applicable to all flares.

Response 33: Local refineries currently operate several “NSPS” flares that comply with proposed 160ppm H2S limit. Staff has determined that three refineries will need to install flare gas recovery and treating systems and other
refineries may consider expansion of flare gas recovery and treating systems to comply with the annual SO₂ performance targets, which can also be designed to comply with the proposed 160ppm H₂S limit. Staff has concluded that these systems are technologically feasible, achieved in practice and are cost effective (as part of the monitoring and control proposal for PAR 1118. PAR 1118 has been revised to allow averaging over a period of three hours rather than an instantaneous limit. Also, this proposed requirement does not include vent gases resulting from emergencies, shutdown, startup or relief valve leakage. Staff believes that other possible vent gas can be controlled to comply with the H₂S limit as part of the new and expanded recovery and treatment systems.

Comment 34: Because the H₂S limit applies to Essential Operational Needs, refineries needing to install flare gas vapor recovery and treatment systems could be out of compliance with this standard until the control systems are installed.

Response 34: Staff has revised PAR 1118 to exclude relief valve leakage (due to a malfunction) when determining compliance with the H₂S limit. Staff believe all other essential operational needs, as defined in paragraph (b)(4), can be collected and treated to compliant levels. To allow time to install or expand needed control system(s), staff has revised the compliance date to January 1, 2009.

Operation Monitoring and Recording Requirements

Comment 35: Six months after Flare Monitoring and Recording Plan approval may be insufficient time to install a calorimeter to analyze emissions.

Response 35: Staff has revised PAR 1118 to require the installation and operation of a continuous higher heating value analyzer by July 1, 2007.

Comment 36: The requirement to take a sample within the first fifteen minutes of each sampling flare event presents significant logistical hurdles, and in some cases it is an impossibility.

Response 36: PAR 1118 requires the use of automated sampler to collect gases to be analyzed for higher heating value and total sulfur. Staff has determined that automated samplers are currently available and are in operation at most local refineries. These automated samplers can be programmed to take a sample 15 minutes after the start of a flare event.

Comment 37: The requirement for daily sampling is a burdensome and expensive proposition which serves no purpose. There are millions of data points that could be used to develop statistically reliable averages.
Response 37: Staff believes that increased sampling frequency will greatly increase the accuracy of emission data until the continuous monitors are installed. Many data submitted by the refineries was not measured but rather substituted data based on calculations. The cost of daily sampling and analysis has been included in the cost effectiveness determination for PAR 1118. Staff has determined that PAR 1118, which includes daily sampling, is technologically feasible and cost effective.

Comment 38: Sampling during a Sampling Flare Event ought to suffice as the daily required sample.

Response 38: Staff believes that increased sampling frequency will greatly increase the accuracy of emission data until the continuous monitors are installed. Furthermore, the use of data collected during a sampling flare event, such as an emergency, has in most instances, been documented as a value greater than the values measured during a smaller, non-sampling event. However, staff has revised PAR 1118 to allow the use data collected during a sampling event for the required daily sample.

Comment 39: The time limit on breakdowns and unplanned flare monitoring system maintenance of 48 hours per quarter is not feasible. Often, more time is needed because vendors must be called out for repairs. 160 hours annually has been suggested as a viable option to the 48 hours per quarter limit.

Response 39: PAR 1118 has been revised to allow flare monitoring system maintenance and repair of up to 96 hours per quarter, which is at least as stringent as Rule 218 – Continuous Emission Monitoring.

Comment 40: There is no way to determine whether the 14 day per 18 month limit on planned maintenance is feasible, especially given the fact that monitoring systems will now include more components than before and will be more complex. Instead of the aforementioned limit, Rule 218 to should be used to deal with the issues of monitoring system downtime.

Response 40: Data collected by AQMD on continuous emission monitoring systems (CEMS) does not suggest additional time will be needed. However, staff acknowledges that information on the operation of CEMS for flares is less robust. If the pilot study on the total sulfur analyzer shows a potential need for more than 14 days per 18 months, staff can revisit this provision of PAR 1118.

Comment 41: PAR 1118 allows the refinery operator to monitor the presence of a pilot flame using a thermocouple or any other equivalent device approved by the Executive Officer. Providing examples of equivalent devices to a
thermocouple, such as an IR camera, would be helpful for both facility operators and District engineers.

Response 41: Staff has determined that thermocouples and video cameras are currently being used successfully to monitor the presence of the pilot flame on flares. However, staff did not want to limit a refinery’s ability to propose an alternate measurement technique it believes equivalent. Any alternative(s) by the refinery can be proposed to and analyzed by AQMD staff.

Comment 42: The requirement to install a flow meter to monitor and record the purge gas and pilot gas flow to each flare has no greater air quality benefit than using engineering estimates. Furthermore the installation of the proposed flow monitoring devices are far more expensive than engineering estimates and may require that the flare involved be out of service.

Response 42: Staff believes that it is important to establish an accurate emission inventory. Installing flow meters on pilot and purge gas lines will is needed to obtain an accurate measurement of pilot and purge gas to the flares. Flow measuring devices are relatively inexpensive; the cost of this requirement was used in concluding that PAR 1118 is technologically feasible and cost effective.

Comment 43: The language in (g)(5)(B)(i) is unclear. Does the district mean, “all the gases that are delivered to the flares for combustion must be measured and recorded.”? Furthermore, the requirement should specify “vent gases” because there is a need to specifically exclude any assist air or steam for the purpose of insuring clarity.

Response 43: Yes, Clause (g)(5)(B)(i) clearly states “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: All the gases that are delivered to the flares for combustion must be measured and recovered”. To exclude “assist air or steam” from the gas(e) being directed to the flare(s), the refinery will need to demonstrate to the satisfaction of the Executive Officer that assist air or steam does not contain anything that will result in the emission of air contaminant(s). However, the revised definition of Vent Gas excludes assist air or steam injected directly into the flare combustion zone or flare stack via a separate line (not the flare header).

Comment 44: The requirement for flow monitoring instrumentation placement in clause (g)(5)(E)(i) cannot be justified on the basis of an air quality benefit.
Response 44: Accurate emission data, which includes flow measure to the flares, is paramount to determining the amount of air contaminants released to the atmosphere. Staff cannot determine the air quality benefit without accurate flow data. The AQMD Governing Board, on September 3, 2004, directed staff to proceed with rule development to evaluate the recommendations stated in “Evaluation Report on Emissions from Flaring Operations at Refineries”, which included a recommendation to improve the measurement of flare vent gas flows. Staff believes that it is important to establish an accurate emission inventory; installing flow meters in representative locations will do just that. As an alternative to relocation, an owner or operator may upgrade the meter with a totalizer to subtract any reverse flow to a flare gas recovery system.

Comment 45: There is no air quality benefit associated with the requirement in clause (g)(5)(E)(iii) to install an automated flare gas sampling system, a costly and unnecessary investment. Such a sampling system will cost $50,000 to $100,000 according to estimates.

Response 45: Accurate emission data, which includes higher heating value and total concentration of total sulfur, expressed as sulfur dioxide, of gases directed to the flares, is paramount to determining the amount of air contaminants released to the atmosphere. The AQMD Governing Board, on September 3, 2004, directed staff to proceed with rule development to evaluate the recommendations stated in “Evaluation Report on Emissions from Flaring Operations at Refineries”, which included a recommended the installation of continuous monitoring systems to measure the higher heating value and the total sulfur gas concentration of the flared gas. Several local refineries have already installed and operate automated flare gas sampling systems. Staff believes that this equipment will improve the logistics of taking samples, especially during an emergency when refinery personnel are not available to manually collect the required sample(s). Staff has determined the installed cost of the automated flare gas sampling system to be approximately $5,000 based on cost information provided by an engineering general contractor who has installed sampling systems at refineries and the AQMD.

Comment 46: The requirement of installation of Higher Heating Value (HHV) technology is problematic. It is requested that they be pilot tested before they are considered as a requirement for flare system monitoring.

Response 46: Staff has contacted several petrochemical facilities in Texas and Louisiana where continuous calorimeters have been used for a number of years on flare headers for compliance with USEPA 40CFR 60.18 or Texas regulations. Staff believes, based on those testimonials, that a pilot program is not necessary.
Comment 47: Procedures to prevent flaring events caused by recurring equipment breakdowns, detailing the adequacy of maintenance schedules for equipment, process and control instrumentation are not necessary and are a requirement that should be dropped. The issue is already addressed by the requirements for Root Cause Analysis. Furthermore, what constitutes a definition of recurring is unclear and no guarantee can ever be made that there will not be recurring breakdowns. The term “adequacy” used in the requirement is also subjective and should be replaced.

Response 47: PAR 1118 has been revised to streamline the requirements of the FMP and eliminate any redundancy with the “Specific Cause Analysis” (SCA), which replaces the Root Cause Analysis. An SCA is an investigation of the cause of the flare vent where the facility operator also identifies corrective measures to prevent a recurrence of a similar flare event.

Comment 48: There appears to be a misconception that fuel system imbalances only occur as a result of a temporary interruption of pipeline gas sales. Rather, the interruption of pipeline gas sales is probably one of the least common reasons for fuel system imbalances. There is concern that the fact that fuel gas imbalances are specifically addressed implies that they cannot be claimed as an Essential Operational Need, which they are.

Response 48: Staff understands that an interruption in pipeline gas sales is not the only situation that may cause a temporary fuel gas imbalance; the loss of a combustion device such as a heater or boiler may also cause this temporary situation. Staff recognizes that there are essential operational needs that must be directed to the flare. The definition of Essential Operational Needs has been revised to include vent gas resulting from temporary fuel gas system imbalance.

Comment 49: The requirement to specify the schedule and resources that will be used to conduct acoustic and temperature surveys of pressure relief devices is impractical. First, specifying schedules that far in advance, is difficult at best. Furthermore, specifying resources so far in advance serves no useful purpose as resources that complete a particular job at the same high quality are often interchangeable. For instance, contractor A could be replaced by contractor B and the job could be done in the same manner.

Response 49: PAR 1118 has been revised to remove this requirement.

Comment 50: The requirement to provide a list of equipment breakdowns during the previous five years that resulted in vent gas being directed to the flare cannot be guaranteed to be met since refineries have not been required to keep records going back five years.
Response 50: PAR 1118 has been revised to remove this requirement.

Comment 51: The provision requiring that actions be taken to prevent future breakdown is problematic because “prevent” is an absolute term and there cannot be any assurance that future breakdowns will not occur.

Response 51: PAR 1118 has been revised to remove this requirement.

Notification and Reporting Requirements

Comment 52: When an unplanned flare event exceeds a threshold of 100,000 scf of combusted vent gas or 500 lbs of sulfur dioxide emissions, the operator is required to contact the Executive Officer within one hour of the event. This extremely low threshold will result in an excessive number of phone calls to the District. There is also concern that any late, or missed calls could result in NOVs, despite the fact that there are no negative air quality implications.

Response 52: PAR 1118 has been revised to require the refinery to notify the AQMD within one hour, by telephone, of the unplanned release of 100 pounds of VOC, 500 pounds of SO\textsubscript{x}, or 500,000 standard cubic feet of vent gas from a flare. The one hour notification requirement is consistent with Rule 430 – Breakdown Provisions and staff believes it is appropriate in order to conduct timely investigations of flaring events and possible public complaints. The AQMD issues NOVs only after careful consideration of the facts and merits of the failure to meet its’ rule requirements promulgated to protect public health.

Comment 53: The requirement to submit a follow-up report to the Executive Officer within 30 days carries with it the implication that a Root Cause Analysis should also be completed within this time frame, which is an unreasonable request. Furthermore, the requirement will result in resources being re-distributed from areas that have a greater potential for achieving air quality benefits to writing these reports that have no immediate air quality impact.

Response 53: Staff made the requirement for submittal of the Specific Cause Analysis (SCA) consistent with the deadlines in Rule 430 or Regulation XX Rule 2004 (h) for breakdown reports. If needed, a facility may request an extension of up to 30 additional days for submitting the SCA.

Comment 54: The term mitigation used in the requirement for Root Cause Analysis implies that mitigation of emissions is a requirement. Clarification is
needed on this point to prevent the consequences of the subjective nature of the term.

**Response 54:**

PAR 1118 requires minimization of flaring during flaring events and any actions taken by the operator with this purpose should be reported in the SCA.

**Comment 55:**

Facilities are not always able to accurately predict the exact time period of even a planned flaring event, thus making the requirement to notify the district 24 hours prior to such an event difficult at best.

**Response 55:**

Staff understands that emissions reported as part of notification of such schedule changes are estimated at best in which case the facility should notify the AQMD of the revised planned event date and/or time. However, the facility will have the opportunity to refine these estimates once more information about the events become available.

**Comment 56:**

There should be clarification provided that demonstrates that the quarterly report required for submittal within 30 days after the end of each quarter is consistent with “standard” certifications such as other District requirements, EPA requirements etc.

**Response 56:**

PAR 1118 language was revised to be consistent with the certification requirements for quarterly reports in other AQMD rules.

**Comment 57:**

Because of the low thresholds that define a flare event, 500 pounds sulfur dioxide and 100,000 cubic feet of flare gas, many flare events are likely to be nearly continuous, making the requirement to provide an analysis of each flare event difficult.

**Response 57:**

PAR 1118 language has been revised to require a more comprehensive Specific Cause Analysis (SCA) for larger flare events 500 pounds sulfur dioxide, 100 pounds VOC or 500,000 cubic feet of flare gas is combusted and a basic investigation to determine the relative cause (emergency, shutdown, startup, turnaround, specific essential operational need, or unknown if undeterminable) where more than 5,000 cubic feet of flare gas is combusted by the flare. Staff believes that these thresholds are necessary to reduce emissions from flares since they will in effect provide operators useful information regarding the use of flares at their facilities.

**Comment 58:**

Requiring the name of the person who conducted the inspection to be part of the annual acoustical or temperature leak survey for pressure relief devices (PRDs) is not justifiable in any way. Furthermore, the clause, “but not limited to”, which is part of the description of what the report should
include ought to be deleted because it is too open ended and will result in confusion and problems later in terms of enforcement.

Response 58: For the AQMD to effectively review and verify measured and reported data, it is critical that the name of the person(s) conducting the annual inspection of PRDs be recorded. Staff has revised PAR 1118 to remove all “but not limited to” language in the proposed amended rule.

Testing and Monitoring Methods

Comment 59: Neither calorimeters nor sulfur analyzers have been demonstrated to be viable for flare service and both must be tested in a pilot program before PAR 1118 can include a provision requiring the use of semi-continuous heat content analyzer. Furthermore, the District has not justified the cost in terms of air quality benefits of installing these analyzers systems.

Response 59: Staff has contacted several petrochemical facilities in Texas and Louisiana where continuous higher heating value analyzers (calorimeters) have been used for a number of years on flare headers for compliance with USEPA 40CFR 60.18 or Texas Commission of Environmental Quality (TCEQ) regulations. Staff believes, based on those testimonials, that a pilot program is not necessary for this type of analyzer. A local refinery will be install and operate a total sulfur (TS) analyzer in March 2006. Staff believes that sufficient data will be collected to demonstrate the effective operation of the TS analyzer well in advance of the July 1, 2007 date when petroleum refineries are required to install and operate this type of analyzer. Staff will make a commitment in the PAR 1118 adopting Resolution to conduct a study of the TS analyzer at the local refinery prior to the requirement going into effect. Accurate emission data, which includes total heating value and concentration of total sulfur, expressed as sulfur dioxide, is paramount to determining the amount of air contaminants released to the atmosphere. Staff can not determine the air quality benefit without accurate emissions data. The AQMD Governing Board, on September 3, 2004, directed staff to proceed with rule development to evaluate the recommendations stated in “Evaluation Report on Emissions from Flaring Operations at Refineries”, which included a recommendation to improve the measurement of flare vent gas. The requirement of continuous monitoring implements that recommendation.

Comment 60: In subdivision (j) Testing and Monitoring Methods (B), the sulfur content of vent gas should be expressed as a reduced sulfur compound rather than as sulfur dioxide.

Response 60: The 2003 AQMP Control Measure CMB-07 requires a reduction in the sulfur dioxide emissions from flares operated at petroleum refineries and
related facilities. Therefore, staff has determined that it is appropriate to calculate and report concentration of total sulfur, expressed as sulfur dioxide, in the vent gas as sulfur dioxide.

Comment 61: There is absolutely no justification for the provision that samples be analyzed by a third-party. It should be acceptable for the sample to be analyzed in a refinery lab that meets District operating standards.

Response 61: PAR 1118 has been revised to allow AQMD approved laboratories to analyze for higher heating value and concentration of total sulfur, expressed as sulfur dioxide, (reported as sulfur dioxide).

Comment 62: Under subdivision (k) exemptions, the terms “catastrophic” and “major” are subjective and the language ought to be clarified.

Response 62: Subparagraph (k)(1)(A) relieves a facility from collecting “grab” samples for higher heating value and concentration of total sulfur, expressed as sulfur dioxide, during a flare event resulting from a catastrophic event including a major fire or an explosion at a facility. Staff agrees with petroleum refineries that safety is paramount; only the facility experiencing a significant flare event and the specific circumstances pertaining to that event knows if it is safe to send in personnel to collect a sample. PAR 1118 has been revised to better define circumstances during which sampling is infeasible or considered a safety hazard.

Comment 63: Requiring facilities to submit a written document to explain flaring events caused by natural disasters or acts of war or terrorism is pointless, because the District would already be well aware of such events.

Response 63: Staff believes that, in order to maintain an accurate record, this requirement is appropriate.

Comment 64: The exemption in paragraph (k)(2) should also include flare sulfur dioxide emissions resulting from interruptions of power supply beyond the refinery’s control.

Response 64: PAR 1118 language has been revised to exclude emissions from power outages, other than due to an interruptible power agreement, from the annual performance target.

Attachment A:

Comment 65: The District should refrain from specifying the materials of construction, or considering area classifications in a rule. Facilities must always be in

Proposed Amended Rule 1118 IX-19 October 2005
control of the aforementioned issues as they are the ones that specify, purchase and operate equipment. This general provision extends to specifics in Attachment A such as installation issues like hot-taps.

Response: 65

The goals of analytic and monitoring requirements are to ensure that complete, accurate meaningful and verifiable data are collected. In that this requirement contributes to ensuring that an analyzer will not have temperature changes that may compromise its ability to accurately measure flare gas parameters, it is both necessary and within AQMD’s purvey. Area classification requirements were selected for harmony with building requirements in the region and to ensure safety of monitoring staff.

Comment 66:
The lower threshold of 0.1 in the velocity range is possibly unrealistic and can certainly not be justified based on any air quality benefits.

Response 66:
The manufacturer of the flow meters used by facilities subject to PAR 1118 has stated that the meters can accurately measure flow as low as 0.1 feet per second. However, staff will include a twenty percent margin to account for any fluctuations due to transient flow. PAR 1118 has been revised to raise the threshold to define a flare event as 0.12 feet per second or greater. As previously stated in Response 46, accurate flow data is necessary to determine emissions and air quality benefit as well as air quality detriment.

Comment 67:
It is assumed that data recorded will be transferred to a Data Collection System (DCS) and stored there.

Response 67:
The assumption is correct and all required records have to be kept by the facility for a period of five years.

Attachment B:

Comment 68:
Assuming that the flow rate is the maximum design capacity of the flare when the maximum range of the flow meter is exceeded is an overly pessimistic assumption which will quickly cause emissions performance goals specified in (d)(1) to be exceeded.

Response 68:
Staff has revised PAR 1118 to allow the operators of facilities subject to this rule to substitute flow data that was not measured using both the maximum and the average flow measured during the previous 20 quarters. Based on flow data collected from 2000 through June 2005, the proposed methodology would capture approximately 97 percent of flow data previously reported. Operators also have the option to demonstrate to the
AQMD that no flow occurred during the time when the flow meter was non operational through the monitoring of the water seal level associated with the flare or through any other operational parameters and/or other process data. Furthermore, the provisions applicable to the non-sampling events have been revised to allow these facilities to rely on previously measured events rather than relying on data substitution procedures. In addition, staff has committed to evaluate the use of the data substitution procedures by industry during the first year of implementation of PAR 1118 and report back to the Governing Board with any recommendations.

Comment 69: Defining the flow rate at the lower range when the flow rate is below the valid lower range of the flow meter means that a refinery could never use “zero”. Without a designation of zero a “Flare Event” as defined would never actually end. This applies to both flow meters and to a combination of flow meters and on/off flow indicator switches.

Response 69: Flow meters are capable of measuring flows as low as 0.1 feet per second. PAR 1118 has been revised to establish a flare event at 0.12 feet per second or greater. The twenty percent difference between the lower limit capability of the flow meter and what constitutes a flare event is adequate for an operator to discern flow from no flow.

Comment 70: Using the maximum range of the meter as the assumed flow rate for any missing data is not acceptable. Nothing justifies this use of worst-case assumptions, especially in light of the mitigation fees that would apply if emissions performance goals are exceeded. Instead of just using worst-case assumptions, there should be a provision that considers other factors such as water seals that remained intact.

Response 70: PAR 1118 has been revised to allow facility operators to demonstrate to the AQMD that operational records, such as water seal level or other approved parameters in the Flare Monitoring and Reporting Plan, that a flare event did not occur. Furthermore, the data substitution provisions of PAR 1118 have been revised and the worst case assumptions are no longer applicable.

Comment 71: The requirement to fill in any missing data with the measurement of the highest sulfur concentration in the vent gas from the previous year is exceedingly harsh and based on unrealistic assumptions. First, it is unlikely that the peak value from the previous year would always exceed any estimate based on engineering knowledge. Secondly, this requirement could lead to a situation in which the payment of the mitigation fee would be based on fictitious emissions instead of real ones. Instead of this worst-case data use, facilities ought to be able to use another appropriate
estimate if the facility provides adequate justification for that estimate’s use.

Response 71: Staff has revised PAR 1118 to allow the operators of facilities subject to this rule to substitute concentration of total sulfur, expressed as sulfur dioxide, data that was not measured using both the maximum and the average concentration of total sulfur measured during the previous 20 quarters. Based on concentration of total sulfur, expressed as sulfur dioxide, data collected from 2000 through June 2005, the proposed methodology would capture approximately 97 percent of total sulfur concentration data previously reported. After the continuous total sulfur analyzers are certified by the AQMD, facility operators also have the option to collect a “grab” sample during the flare event and use that analysis to substitute data for time when the total sulfur analyzer was non-operational. PAR 1118 also allows the facility operator the option to demonstrate to the AQMD that total sulfur can be estimated through alternative methods using recorded and verifiable operational parameters and/or process data to be representative of the total sulfur concentration.

Comment 72: There is no reason why the single highest measurement of concentration of sulfur or heat content in the previous 365 days should be used when it would be more equitable to use an average of the values from the previous year.

Response 72: See Response 721.

Definitions

Comment 73: The very low velocity threshold of 0.1 ft/sec that helps define a flare event is problematic because it means that facilities are very likely to have continuous flare events. Part of the problem is that in some flare configurations, vent gases may enter the flare header, pass by the meter and then be recovered by the vapor recovery system before breaking through the water seal. This typically results in flow meter reading greater than .1 ft/sec to as high as about 1.5 ft/sec with no vent gas released to the flare. Therefore, a flare event defined by the presence of flow at a velocity of 0.1 ft/sec would force a recording of a continuous flare even when there is no flow to the flare. Furthermore, flare events indicated by flow monitor signals, which are not verified by on/off meters, water seal monitors, or video monitoring, must be excluded from flare events, as defined. A better definition of flare event is, “FLARE EVENT is any intentional or unintentional release of vent gas to a flare based on positive indications or other instrumentation including, but not limited to, water seal breakthrough, on/off indicators, or video monitoring.
Response 73: The definition of Flare Event has been revised to address the situations where vent gas is measured by the flow meter but through the use of the water seal, the vent gas is processed by the gas recovery system. The revised definition includes the following language: “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.”

Comment 74: The definition of an emergency should include operational upsets to be consistent with federal rules. A better definition would be: “Emergency, for this rule, means a condition beyond the reasonable control of the owner or operator of a refinery requiring immediate corrective action to restore normal and safe operation, which is caused by any sudden, infrequent, and not reasonably, preventable failure of equipment or of a process to operate in a normal or usual manner, force majeure, act of war or terrorism, or external events beyond the control of the operator. Failures that are caused in part by poor maintenance or careless operation are not emergencies.” (Reference: Based on 40 CFR 60, Subpart A 60.2 - Malfunctions) In addition, the current definition of Emergency Service Flare in Rule 1118 includes “emergency process upset condition.”

Response 74: The definition of Emergency was revised to include “not reasonably preventable”. However, staff does not believe “process upset” should be included in this definition; specific situations will be listed in the definition of Essential Operational Need”. The definitions of Emergency and Emergency Service Flare cannot be identical in application since clean service flares and general service flares also process vent gases from emergencies.

Comment 75: A better definition for “FLARE” is the one in the draft BAAQMD rule (definition 12-12-203).

Response 75: PAR 1118 language was modified to incorporate elements from the BAAQMD in the definition.

Comment 76: The definition of “FLARE GAS RECOVERY SYSTEM” would not apply in all cases. The following definition should be used instead. “Flare Gas Recovery System is a system consisting of permitted equipment used to prevent or minimize the combustion of vent gas in a flare.”

Response 76: Staff believes the suggested definition is too vague and open-ended.

Comment 77: The definition of “FLARE MONITORING SYSTEM” is inappropriate with the phrase “including but not limited to.” There needs to be a clear
understanding between the AQMD and industry of what a flare monitoring
system consists of.

Response 77: PAR 1118 was revised to delete the phrase “but not limited to.” The
definition of Flare Monitoring System includes higher heating value and
total sulfur analyzers, flow meters, and on/off flow indicators.

Comment 78: The definition of “GENERAL SERVICE FLARE” includes activities,
such as tank vapor displacement, blowdowns, and “clean up” which
should be included in other definitions and/or in the listing of allowable
flaring at Rule 1118 (c)(2)(A).

Response 78: Staff believes that these activities are within the scope of essential
operational need(s) or qualify as startups, shutdowns and turnarounds.

Comment 79: The definition of “HYDROGEN PRODUCTION PLANT” is overly
specific.

Response 79: Staff believes this definition is appropriate.

Comment 80: Instead of using the current definition of “NATURAL GAS” the District
should consider using an existing definition of “pipeline quality natural
gas” from either CPUC or EPA.

Response 80: Staff believes the current definition of Natural Gas is appropriate.

Comment 81: The following definition of “PURGE GAS” is better than the current
version. “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 and to prevent the formation of an explosive mixture due to
ambient air ingress.”

Response 81: The definition of Purge Gas has been revised based on your suggestion.

Comment 82: The definition of a REPRESENTATIVE SAMPLE ought to be consistent
with other requirements such as the specifications for Higher Heating
Value and Total Sulfur analyzers.

Response 82: The proposed amended definition for Representative Sample was modified
for consistency with requirements for analyzers.
Comment 83: In the definition of SAMPLING FLARE EVENT it must be made clear that the refinery must initiate the request.

Response 83: PAR 1118 language was modified to reflect that a facility is to propose a different Sampling Flare Event threshold for the Executive Officer’s approval.

Comment 84: The definition of SHUTDOWN does not take into account that shutdowns occur for reasons other than maintenance, repair, or replacement of equipment. The following definition is more complete. “Shutdown is the process of stopping the operation of a process unit or piece of equipment for any reason, including preparations necessary for maintenance work.”

Response 84: Staff believes that the suggested definition is too vague and may become a loophole to allow routine flaring.

Comment 85: A more complete definition for STARTUP is the following. “Startup is the process of initiating and achieving normal operation of a process unit or piece of equipment.

Response 85: PAR 1118 has been revised to include an expanded definition for startup that takes into account parameters, such as pressure, temperature, feed rate, etc. to characterize normal operation.

Comment 86: In the definition of TURNAROUND it would be helpful to add language regarding installation of new equipment.

Response 86: Staff has revised the definition of Turnaround to include “installation of new equipment.”

Comment 87: The definition of VENT GAS does not specifically exclude “assisting air or steam, flare pilot gas and any continuous purge gases.” These exclusions must be included in the proposed definition. A more complete definition is the following. “Vent gas is any gas generated at a facility subject to this rule that is routed to, and combusted in a flare, excluding assisting air or steam, flare pilot gas, and any continuous purge gases.

Response 87: Staff has revised definition of Vent Gas to exclude assist air or steam injected directly into the flare combustion zone or flare stack via a separate line (not the flare header). However, any gas that is generated at a facility subject to PAR 1118 and is directed a flare is considered vent gas.
MISCELLANEOUS

Comment 88: A flare designed for smokeless flaring at full capacity and designated for emergency use only should not be required to have a video monitor installed for it.

Response 88: Staff is not aware of any flare that is smokeless over the whole operating range up to maximum design. Even if this existed, there is always the possibility of losing steam injection that could result in visible emission, therefore having a video record is appropriate.

Comment 89: All current activities and uses of the flare should be considered essential operational needs. Without such designation, facilities planning to install complete vapor recovery and treatment systems in the next few years would face challenges relating to certain requirements prior to their installation of the vapor recovery system.

Response 89: Staff disagrees with this statement that would effectively allow any flaring to take place and make the rule amendment futile. However, the rule language has been revised to allow more time for these facilities that intend to install additional vapor recovery treatment capacity and have affirmed steps toward that goal.

PRELIMINARY STAFF REPORT COMMENTS

Comment 90: The suggestion that a flare gas recovery and treatment system can prevent temporary fuel gas imbalances is incorrect; such systems are not effective for that purpose.

Response 90: Staff agrees that such a system would not prevent a fuel gas imbalance, but rather flare emissions may be minimized by the use of this equipment.

Comment 91: The rule is not necessary since the AQMD Basin is in attainment with the federal SOx standards and flare emissions have already been reduced by 80%.

Response 91: Staff disagrees. SOx emissions are precursors to particulate matter (PM) emissions and the AQMD is not in attainment for PM 10 (particulate matter less than 10 microns aerodynamic diameter) and PM 2.5 (particulate matter less than 2.5 microns aerodynamic diameter). The reductions achieved to date were voluntary and were achieved primarily through operation procedural changes implemented by the refineries. Furthermore, a close look at the current differences of the recovery and treatment capacity of the various facilities indicates that additional capacity for some facilities is feasible to further minimize flaring and
Comment 92: It is not fair to assess mitigation fees based on an industry-wide performance, where an individual facility has no control on emissions from a competitor. Also, the standard for an “ultra-clean facility” is not attainable.

Response 92: PAR 1118 has been revised to require petroleum refineries to achieve a facility-specific declining annual sulfur dioxide performance target. Facilities that exceed the annual performance target are subject to mitigation fees and must also submit a Flare Minimization Plan for public comment and Executive Officer approval. PAR 1118 no longer contains an “ultra-clean” facility compliance option.

Comment 93: The estimated emission reductions based on 2003 emissions inventory is not appropriate since it does not take into consideration further reductions realized in 2004. Further, the use by the District of the DCF method yields a lower number for cost effectiveness.

Response 93: Staff acknowledges that flare emissions have trended down and that 2004 emissions are lower than the previous stated baseline year 2003. Since emissions may vary significantly from year to year due to turnarounds and other unforeseen events in petroleum refinery operations, it is appropriate to use a multiple year average as an emissions baseline. The staff report has been revised to average sulfur dioxide emissions and vent gas flow rates for the years 2001, 2002, 2003 and 2004 to establish the baseline for calculating emission reductions and the cost effectiveness of PAR 1118.

Cost effectiveness analysis is a tool to generate a cost effectiveness factor for a control measure. By comparing the cost effectiveness factors of several control measures with each others, one can acquire knowledge about the costs of each control measure relating to their effectiveness in controlling a particular pollutant. It is necessary to compare cost effectiveness factors of different control measures derived using the same methodology and the same assumptions. The AQMD has been using Discounted Cash Flow Method (with a 4% real interest rate) to determine the cost effectiveness factor for numerous proposed rules since 1995.

Comment 94: The Staff Report should include the CARB Resolution 86-60 for reference.

Response 94: CARB Resolution 86-60 is included as an attachment to this staff report.
Comment 95: In contrast with the Bay Area Air Quality Management District (BAAQMD) flare rule, PAR 1118 is far more complex and has duplicative requirements.

Response 95: BAAQMD has two flare rules: one for monitoring and one for control of flare emissions, whereas PAR 1118 has one rule that includes both these aspects. Moreover, the approach of the two Districts to flares is different, BAAQMD is requiring Flare Minimization Plans while AQMD’s PAR 1118 establishes performance targets for controlling and minimizing flare emissions.

Comment 96: The Staff Report needs to explain the applicability of New Source performance Standards (NSPS) requirements to flares with respect to effective dates.

Response 96: Staff has clarified in the Staff Report all applicable dates that trigger NSPS requirements for flares (40CFR Subparts A and J).

Comment 97: Acid gas in the Preliminary Draft Staff Report (PDSR) should be described as "a highly concentrated waste stream of hydrogen sulfide gas (up to 90 percent pure) and sour water stripper gas (about 30 percent pure)" The PDSR incorrectly states EPA’s position in the October 2000 Enforcement Letter, which is..."refineries should have adequate capacity at the back end of the refinery to process acid gas”.

Response 97: The description of acid gas was enhanced as suggested. Staff believes that the title of the October 2000 Enforcement Letter summarizes EPA’s position that routine flaring is not considered “Good Pollution Control Practice” and it “May violate the Clean Air Act”.

Comment 98: The use of the same concepts in the Consent Decrees that EPA has entered with some refiners used in the amendment of Rule 1118 may represent a duplication of a federal regulations and the AQMD Board must recognize it in its findings upon rule adoption.

Response 98: Staff disagrees. The Consent Decrees are not federal regulations and they may sunset according to specific clauses in each of them, based on each refinery’s compliance record for a certain period of time following the signing of the Consent Decree.

Comment 99: The statement in the Staff Report that refineries burn “waste gases” in flares is a false assumption.

Response 99: Staff has revise the staff report and the word “waste” was removed.
Comment 100: Stating that visible emissions are caused by insufficient steam is inconsistent with the smokeless capacity of a flare, since there are limits to how much steam can be used. The staff report should mention that a facility with a flare smoking for 5 minutes within 1 hour could receive two Notices of Violations, one for violating Rule 401 and one for violating Rule 1118.

Response 100: Staff agrees that when the smokeless capacity is exceeded there is not enough steam to accommodate the high vent gas flow, but acknowledges that this is due to the limitations in the flare design and a clarification was made in the staff report.

Assuming that a flare was found having visible emissions in excess of Ringelmann 1 or 20 percent opacity for 5 minutes within 1 hour due to a situation other than a valid breakdown, force majeure or power curtailment beyond the operator’s control, only one NOV would be issued with two counts of violating Rule 401 and Rule 1118, respectively. If visible emissions were in excess of Ringelmann 2 or 40% opacity, there would be an additional count for violation of California Health and Safety Code 41701.

Comment 101: The operational status of a flare does not involve having just the pilot lights on and the amount of purge gas used depends on other variables than just the flare design.

Response 101: The Staff Report has been revised to clarify these issues as suggested.

Comment 102: Clean Service Flares should be exempt from all requirements except for monitoring and recording as specified in Table 1.

Response 102: Staff disagrees. All flares have emissions potential and all significant flare events need to be accounted for in the form of a Specific Cause Analysis or a relative cause analysis, as required in PAR 1118. However, a Clean Service Flares is defined as a flare that is designed and configured by installation to combust only natural gas, hydrogen gas and/or liquefied petroleum gas, or any other gas(es) with a fixed composition vented from specific equipment which has been determined to be equivalent and approved in writing by the Executive Officer. Therefore, based on this definition, a Clean Service Flare would have very low sulfur dioxide emissions, and as such would contribute very little to the annual sulfur dioxide performance target. Clean Service Flares are not required to be monitored with higher heating value or total sulfur analyzers and are not required to have daily vent gas “grab” samples taken. However, the operator must collect grab samples for all sampling flare vents.
CHAPTER IX – COMMENTS AND RESPONSES

Comment 103
The staff report acknowledges that flares are used as control devices that prevent the release of VOC to the atmosphere, but the rule would prohibit this type of use.

Response 103:
Staff acknowledges that there are flares being used as control devices for VOCs. These flares were granted far in the past and would not be allowed for such use if requested by facilities today since the destruction efficiency for flares varies widely from 70 to 97 percent depending on atmospheric conditions and the quality of vent gas combusted. By contrast, thermal oxidizers are designed with a specific residence time, are able to maintain stable combustion temperatures, which results in destruction efficiencies in excess of 99%, are therefore more suited as control devices for VOCs.

Comment 104:
Excessive steam may lead to incomplete combustion and odors downwind. Adding high BTU gases to a flare to improve the combustion efficiency would be prohibited by the rule.

Response 104:
Staff believes that use of excessive steam may extinguish the flame and result in potentially high volumes of odorous and/or toxic substances being released from a flare. Boosting the BTU content of a vent gas with low HHV to ensure appropriate combustion efficiency is allowed as an Essential Operational Need in PAR 1118.

Comment 105:
Federal Regulation 40CFR60.104 has a 160 ppm limit for H\textsubscript{2}S, averaged over 3 hours. There should be mention of AQMD Rules 1123 and 1176 and federal regulations requiring control of VOCs.

Response 105:
The staff report was expanded to include the clarification on the H\textsubscript{2}S limit. The other rules mentioned do not apply to the operation of a flare, only to control of VOCs, and therefore will not be discussed.

Comment 106:
The report should clarify that flares prevent the release of raw VOCs to the atmosphere. The report should substantiate any “concerns” that OSHA and EPA have regarding the petroleum industry and any claims made by EJ groups.

Response 106:
The staff report has been revised to clarify these issues.

Comment 107:
Most of the "possible alternatives" suggested for minimizing flaring that are listed in the staff report are speculative and lack any foundation.

Response 107:
The suggested possible alternatives are taken from the “Episodic Release Reduction Initiative” document, issued by EPA on July 5, 2001 as a
collaborative effort of EPA, the (Texas Commission of Environmental Quality (TCEQ), the Louisiana Department of Environmental Quality (LA-DEQ) in cooperation with 13 petroleum refineries.

Comment 108: There is an economic incentive besides the environmental benefit for flare gas recovery (FGR), as long as the refinery has adequate storage for the recovered gas, or else it would have to flare it.

Response 108: Staff agrees and the clarification was made in the staff report.

Comment 109: Staff seems to have relied on an article in the Oil & Gas Journal to determine the necessary capacity of a flare gas recovery system. The article represents the author’s opinion, not necessarily universally applicable guidelines.

Response 109: Staff has expanded the staff report to include guidelines as stated in API 521 for flare gas recovery system sizing, where it is recommended that the system be sized such that it is able to operate over a “wide” range of dynamically changing flow rates. Thus the opinion expressed in the Oil & Gas Journal article is in agreement with the API guidelines.

Comment 110: The significant emission reductions already realized suggest that there are limited benefits for amending the rule.

Response 110: PAR 1118 implements the recommendation of the Governing Board regarding improved monitoring, recordkeeping and recording as well as establishing annual sulfur dioxide, already realized performance targets which will ensure that emission reductions already realized are permanent, real, quantifiable and enforceable and that further reductions are achieved in the future.

Comment 111: The concept of an alternative to a Flare Minimization Plan is worthwhile; the District should encourage refineries to opt for SOx performance targets.

Response 111: PAR 1118 has been revised to require petroleum refineries to comply with a declining annual sulfur dioxide performance target of 1.5, 1.0, 0.7 and 0.5 tons per year for calendar years, 2006, 2008, 2010 and 2012 respectively. A Flare Minimization Plan will only be required for petroleum refineries exceeding the annual performance targets.

Comment 112: There is no need to require continuous HHV analyzers since on average this parameter is expected to be constant.
Response 112: The fact that, on average, the HHV will be constant was an assumption used to estimate emission reductions. For calculating the emissions of each flare event with accuracy, a continuous monitor is the best option to use.

Comment 113: The statements by staff regarding the cause of flare events are misleading, are based on tabulated data from the September 2004 “Flare Report” that are inconclusive. In addition, please explain your assumptions in calculating emission reductions that are used for cost analysis and cost effectiveness calculations.

Response 113: Staff disagrees. The data presented in the Preliminary Draft Staff Report was based on 2003 obtained from the “Evaluation Report on Emissions from Flaring Operations at Refineries” (September 2004), which is a summary of data submitted by facilities to comply with monitoring and reporting requirements of the Rule 1118. The Staff Report has been updated to include data for calendar years 2001 through 2004 to calculate average vent gas flow and emissions from flares. Staff has determined that the average flow and emissions data is most representative data for the random, cyclical operation of the flares. Staff believes that emergencies, startup, shutdown, turnaround and fuel gas balancing events are a significant and determinant event/operation that should have been easily identified and reported to the AQMD. The total vent gas flow and calculated emissions other than sulfur dioxide and the measured total sulfur emissions, calculated as sulfur dioxide are accurate based on flow measurement, sampling, analytical, and published emission factors. Staff has met with two of the three facilities that have been identified in the staff report as needing (projected) additional gas recovery and treatment system capacity. These two “larger” facilities confirmed the need to install four systems totaling 13 mmscf capacity. Staff has determined that the third facility would install a system with 0.3 mmscf capacity. Staff has estimated the size of the systems based on historical vent gas flow. These systems will minimize vent gas directed to the flares which will reduce sulfur dioxide and other criteria air contaminants.

Comment 114: Some suggested flare controls might have been considered technically feasible; however, practicality, costs and cost effectiveness were not necessarily considered.

Response 114: The staff report language was modified to clarify that these controls were technologically feasible.

Comment 115: Refineries that may not have to install flare controls will still incur significant costs for monitoring and other requirements of PAR 1118; in aggregate, complying with the rule will be a significant expenditure.
Response 115: Monitoring and other requirement costs were included by staff in the cost-effectiveness analysis of the proposed rule. Staff has determined that PAR 1118 is both technologically feasible and cost effective.

Comment 116: The assumptions made in the staff report for determining cost-effectiveness will need to be evaluated by individual facilities and commented upon. It is unclear whether three or four flare gas recovery and treatment systems are proposed and the number of flow meters for pilots may be triple than that indicated in the staff report.

Response 116: Staff has estimated that four flare gas recovery and treatment systems would have to be installed at three petroleum refineries; The four systems will minimize vent gases to eight flares that currently are not connected to any gas recovery and treatment systems. Staff’s analysis is discussed in Chapter VI – Cost and Cost Effectiveness. The number of flow meters for the pilot gas was assumed to be one meter per flare, located on the natural gas line before it splits in individual lines for each pilot.

Comment 117: The case study used in the staff report to determine the cost of a flare gas recovery system was related to acid gas flaring. It would not be unreasonable for staff to contact each of the eight facilities subject to the rule to evaluate the cost of necessary expenditures required by the rule.

Response 117: Staff has conducted interviews with subject facilities to assess compliance with future proposed rule requirements. For better accuracy in estimating costs, staff has expanded its analysis to two additional case studies from the data submitted by two local refineries for the installation and subsequent operation of two flare gas recovery and/or treatment system in 1993 and 2001.

Comment 118: Staff needs to explain how the necessary size of a recovery system was determined.

Response 118: The staff report states that for the flare considered for upgrade with a recovery system, the quarters with the highest flow between 2000 and 2003 were selected; then an average daily flow for those quarters was calculated. Based on a review of technical literature on flare design, the capacity of the recovery system was estimated at 2-3 times the daily flow rate.

Comment 119: It appears that staff may have underestimated some equipment and labor costs; refineries could provide some data in this respect.
Response 119: Staff used cost information supplied by the refinery in Billings, Montana, as well as the cost data from two local refineries that installed control equipment in 1993 and 2001. Although the systems installed varied in scope and size, the cost of the flare gas treatment capacity was consistent, ranging from $8.32 to $8.77 million per four million cubic feet of gas recovered/treated. Staff will review any cost data supplied by refineries.

Comment 120: The quoted prices for different pieces of equipment should be provided to refineries for evaluation.

Response 120: Chapter VI - Cost and Cost Effectiveness lists the cost of control, monitoring and labor. The PAR 1118 Administrative Record contains the actual quotes and facility-specific cost information. Some of this information is considered confidential. Any non-confidential information can be provided to interested parties upon written request.

Comment 121: When calculating the cost of equipment over time, staff did not factor in adjustments for inflation.

Response 121: Staff disagrees. The cost of future expenditures was adjusted for inflation.

Comment 122: Annual costs should include taxes and insurance.

Response 122: The total installed cost includes taxes and insurance.

Comment 123: The annual estimated savings due to recovered gas should be based not on the maximum capacity of the compressors but rather on the average flow rate of the gas recovered. Staff needs to explain the assumptions made in calculating the savings.

Response 123: Staff has revised its analysis to use the annual average flow rate of vent gas recovered through the installation of additional vent gas recovery and treatment systems. Please refer to Chapter VI – Cost and Cost Effectiveness for a discussion on the assumptions used in calculating the cost savings.

Comment 124: Staff has not clarified the necessity of the rule for ozone attainment.

Response 124: The proposed rule amendment is necessary since oxides of sulfur (SOx) are precursors to PM10 and PM2.5. Since the rule is designed to minimize flaring and associated emissions, in addition to the SOx reductions, the rule will result in concurrent reductions of other criteria pollutants such as hydrocarbons, oxides of nitrogen and carbon monoxide, all of which are precursors to ozone.
Comment 125: We believe that the best way to protect communities is to require all the refineries to submit a Flare Minimization Plan (FMP), which will be subject to public participation. CBE believes an FMP is the best and most transparent approach to identify unnecessary flaring practices and equipment and procedures that eliminate routine flaring. Performance targets, while important, do not identify unnecessary flaring categories and allow routine flaring within the performance targets.

Response 125: PAR 1118 establishes a multi-pronged strategy to ensure that flaring and associated emissions are minimized. Therefore, the performance targets should not be viewed in isolation from the other provisions of the proposed amendment. Specifically, PAR 1118 has explicit provisions that would prohibit any unnecessary or so-called routine flaring. The proposed amendment states that no flaring is allowed other than emergencies, startup, shutdowns or essential operational needs. Staff went to great lengths in working with all stakeholders to carefully define all these terms in the rule. PAR 1118 would also require facilities to complete a detailed analysis of larger flare events and to identify the cause of smaller flare events.

In response to the comments received, staff amended its proposal to also require facilities to conduct an audit of their flare gas recovery and treatment capacity; identify past emission reduction efforts and future efforts to further reduce flaring and associated emissions, and to evaluate options to reduce flaring during planned events, such options as slowing the depressurization of vessels, storing vent gases, etc.

In addition to the flaring minimization strategies mentioned above, PAR 1118 establishes annual facility-wide performance targets that seek to incrementally reduce emissions starting 2006 through 2012. These performance reduction targets, which have been recently strengthened and are now designed to exceed the AQMP targets by at least 75 percent, are accompanied by substantial mitigation fees that would be triggered in the event the performance targets are exceeded. The staff proposal also significantly strengthens the emissions data gathering and monitoring procedures of the rule which will significantly improve the emissions data quality and a facility’s ability to refine its flare minimization strategy.

Staff has also committed to evaluate the Bay Area Air Quality Management District Rule 12 – Flares at Petroleum Refineries requirement to implement Flare Minimization Plans and the resultant installation of controls and report back to the Governing Board with any recommendations.
Comment 126: In addition, the FMP should require a Best Available Retrofit Control Technology (BARCT) assessment and an audit (list) of equipment, processes and procedures to reduce flaring caused by non-emergency, planned start-ups and shutdowns and flaring events resulting from power curtailments.

Response 126: As stated in Response 125, staff believes that annual performance targets are more effective than FMPs to reduce flare-related emissions from refinery flares. Regardless, staff has revised its proposal to require each facility to conduct an audit of its flare gas recovery and treatment capacity and identify past and future control actions. Refineries that exceed the annual performance targets are then required to submit an FMP. The required elements of this FMP are nearly identical to the list of elements suggested by the commenter, which includes detailed technical information regarding their flare system, policies and procedures related to emergency and planned flaring, audits of their flare gas recovery capacities, flare gas storage and treating capacities.

Comment 127: PAR 1118 performance targets need to be significantly lower and a daily limit for both SO\textsubscript{X} and VOC should be required to limit the health impact of flaring activities on the community.

Response 127: The annual performance target has been lowered to 0.5 ton SO\textsubscript{2} per million barrels processed effective January 1, 2012. This revised proposed target is approximately 70 percent lower than the baseline emissions used in the cost analysis for this proposed rule and approximately 75 percent lower than the AQMP Control Measure CMB-07 targets. Also, see Response 125.

Staff has determined that it is impractical at this time to establish a daily emissions target for SO\textsubscript{2} or VOC because the flares are operated to reduce vent gases resulting, in large part from emergencies, and essential operational needs. These are random events and associated emissions vary significantly. Based on reported emissions data (reductions documented since 1999), refineries have initiated procedures to minimize vent gas releases from shutdowns and startups.

PAR 1118 implements Step II of Control Measure CMB-07 of the AQMP. In addition, to SO\textsubscript{2} reductions, PAR 1118 will also reduce other criteria air contaminants, including VOC. PAR 1118 limits the types of flaring that are allowed, and requires facilities to minimize flaring. To meet the annual SO\textsubscript{2} performance targets, refineries will have to reduce the amount of vent gas directed to their flare; reducing flow to the flare will have commensurate VOC reductions.

However, through the Board Resolution, staff commits to evaluate the feasibility of establishing daily emissions targets and the appropriateness
of the annual SO\textsubscript{2} emission targets and whether refinements to those targets are warranted, and report back to the Governing Board with any recommendations.

Comment 128: The definition for Essential Operational Needs (EON) must be tightened since it could be used as a loophole by refineries for bad engineering practices. Refineries should demonstrate why these operations are essential.

Response 128: In developing the proposed definition of EON, staff carefully analyzed which specific operations are essential and can not be reasonably controlled by the facilities subject to PAR 1118. In addition, as suggested, the EON definition has been more clearly delineated to alleviate any potential lack of clarity by requiring AQMD analysis of the EONs for each refinery to determine if they meet the definition of EON.

Comment 129: Monitoring is a keystone of the proposed rule and should not be weakened. The quarterly emission reports should be made available to the public expeditiously on the District’s web site.

Response 129: Staff agrees and has committed to make these reports available on the AQMD website as expeditiously as possible.

Comment 130: Notification requirements during planned events and emergencies should be improved since many low-income residents do not have health insurance or adequate health care.

Response 130: Effective January 1, 2006, PAR 1118 requires refineries to provide a 24-hour telephone service to answer public inquiries about planned and current flare events. Staff has also committed in the Board Resolution to continue to work with industry and community members, and other public agencies to ensure that emergency notification procedures address the community needs.

Comment 131: A CLEAN SERVICE FLARE is currently defined as a flare that only combusts “clean” gases, such as natural gas, hydrogen gas and/or liquefied petroleum gas, or any other clean gases with a fixed composition vented from specific equipment. The definition of Clean Service Flare should be modified to also include gases that meet the Rule 431.1 – Sulfur Content of Gaseous Fuels requirement of no more than 40 ppm total sulfur content.

Response 131: Staff disagrees. The original and continuing intent of CLEAN SERVICE FLARE is to limit the combustion of clearly defined clean gas(es) in that specific type of flare. The requirements for clean service flares are less
than those for emergency and general service flares because the emissions potential is significantly lower for those flare meeting the definition of clean service flare. Gases that meet the definition of Rule 431.1 can be refinery gas, which does not have a fixed composition. Therefore, unlike the other clean gases listed in the definition of Clean Service Flare, the composition of refinery gas can vary and therefore, so can the emissions of other combustion contaminants, such as NO$_X$, CO, PM10 and VOC.

Comment 132: Hydrogen production plant flares should not be subject to PAR 1118 because, as demonstrated by the quarterly flare reports, they are low SO$_X$ emitters (less than 40 pounds SO$_X$ per year). Based on the reported emissions data, there are significant differences between a hydrogen production plant flare and a petroleum refinery flare.

Response 132: The purpose of PAR 1118 is to reduce and minimize flaring and flaring emissions from petroleum-related operations. Staff acknowledges that hydrogen production flares are low emitters of SO$_2$ compared to the refineries. However, flares at hydrogen plants do use refinery gas and do emit other combustion contaminants, such as NO$_X$, CO, PM10 and VOC, that are in more significant amounts. Hydrogen production plants do use flares to combust vent gases. The requirements for hydrogen production plants are limited to the demonstration of minimizing flaring at this type of facility.

Comment 133: Subparagraph (c)(1)(D) requires refineries to conduct a Specific Cause Analysis (SCA) when a specific emission or flow rate level is exceeded. Throughout the discussions at the PAR 1118 Working Group Meetings, staff stated SCAs would be required only for those flare events that did not result from a planned operation (shutdown or startup). We request that staff clarify this in PAR 1118.

Response 133: Staff will revise subparagraph (c)(1)(D) to emphasize that the owner or operator of a facility subject to PAR 1118 will have to conduct a SCA for those unplanned flare events exceeding 100 pounds of VOC, 500 pounds of SO$_2$, or 500,000 standard cubic feet of vent gas. For those unplanned flare events less than threshold stated above, the owner or operator needs only to state the cause of the lesser flare event.

Comment 134: We are requesting staff to clarify that under paragraph (c)(3), flaring is only allowed for “planned” shutdowns, “planned: startups and “planned” turnarounds or essential operational needs.

Response 134: Staff disagrees. Operators are required to minimize flaring and then only to flare vent gas resulting from specific operating conditions. The decision/need to shutdown or startup equipment that may result in the
need to flare, whether planned or not planned in advance, can be based on petroleum refineries decision to safely operate specific equipment. Staff believes that the declining annual $SO_2$ performance targets coupled with the progressive mitigation fees and required submittal of a FMP for exceedences of the annual targets and the requirement to identify the cause of smaller flare events and conduct a SCA for larger flare events will require (and provide incentives for) petroleum refineries to minimize all flaring.

Comment 135: To comply with the annual $SO_2$ performance targets and the requirement to minimize flaring, some refineries will need to install a flare gas recovery and treatment system(s). Paragraph (c)(4) allows refineries that will need to install flare gas recovery and treatment systems on more than two flares until January 1, 2010, to install the control system(s) for only those specific additional flares. Paragraph (c)(5) requires all refineries to comply with the $H_2S$ limit by January 1, 2009. Since the control equipment to comply with paragraph (c)(5) is the same equipment that will be used to comply with paragraph (c)(4), we are requesting that the AQMD extend the compliance date for refineries with more than two flare that need control equipment to January 1, 2010.

Response 135: Staff has revised PAR 1118 to synchronize the compliance dates for paragraphs (c)(4) and (c)(5).

Comment 136: The definition of EMERGENCY in PAR 1118 includes the phrase “poor maintenance.” We believe that the phrase poor maintenance is ambiguous and needs clarification.

Response 136: Staff has revised PAR 1118 to clarify that poor maintenance is tied to repetitive flare events from the same equipment that have occurred as a result of the maintenance, or lack of adequate maintenance of that equipment that caused the flare event(s).

Comment 137: The definition of EON includes flaring caused by emergency situations resulting from a process vessel operating pressure rising above the pressure relief valve set point. To ensure the safe operation of process vessels, we are requesting that the AQMD also include in the definition emergency situations resulting from operational temperatures rising above the process vessel temperature set point.

Response 137: Staff agrees that temperatures greater than the design operating temperature specifications for specific equipment could result in a flaring event which is necessary for continued safe operation of that equipment.
The definition of EON PAR 1118 has been revised to include “maximum vessel operating temperature set point.”

Comment 138: Throughout the process to amend Rule 1118, our discussions on the annual SO\textsubscript{2} performance targets were based on the crude oil capacity; the current rule version references crude processed. We request that this clarification be reflected in PAR 1118.

Response 138: During the rule development process, industry identified an inequity of using crude throughput versus crude capacity based on a fixed year of 2004 to establish annual SO\textsubscript{2} performance targets. In any one year, any refinery could be conducting a shutdown or turnaround of a major crude processing unit, which could reduce crude throughput for that baseline year reflecting an artificially low baseline throughput for that refinery. Whereas crude processing capacity more accurately allocates refinery emissions based on normal refinery operations. Local refineries are operating at near capacity; therefore, the difference in emissions impact and reductions based on throughput or capacity are minimal.

Comment 139: Please clarify that for data substitution, a facility can use data from a previous similar event.

Response 139: Staff has revised the data substitution provisions of PAR 1118 to clarify that a facility can use flow, HHV, and total sulfur data from similar flare events that have previously occurred, can be used for data substitution, with the Executive Officer’s approval.

Comment 140: The terms “relief valve” and “pressure relief device” are used in the definition of EON and in the requirement to conduct an annual leak survey. Please clarify the meaning for each of these terms in PAR 1118.

Response 140: A relief valve is the all inclusive, general category that includes all valves that are designed and installed for the purpose of protecting equipment from operating pressure greater than design pressure for the safe operation of that equipment. A pressure relief device is a specific type of relief valve.

Comment 141: Staff included language in the rule that allowed sampling flare events that occurred within 15 minutes of each other to be counted as one sampling event if the facility can show that the events were from a common cause and the same process unit. Similar language should be incorporated in the definition of SAMPLING FLARE EVENT.
Response 141: Staff agrees and has revised the definition of SAMPLING FLARE EVENT as suggested.

Comment 142: The ARB requests that staff revise the definition of ESSENTIAL OPERATIONAL NEED in section (b)(4) to include a mechanism for the District’s Executive Officer to approve or reject activities identified by refinery operators as an “essential operational need” and that staff will commit to annually evaluate the continued progress of refineries in the District to minimize their emissions of all pollutants from flares. As part of this evaluation, District staff should provide a summary of the emissions by year by refinery. District staff should use this information to appropriately develop and recommend future amendments to the rule.

Response 142: Staff agrees. The definition of ESSENTIAL OPERATIONAL NEED has been revised to include language that essential operational need is “an activity determined by the Executive Officer to meet” one of the following (specific listed activities). In addition, staff has committed in the Resolution to review the definition of ESSENTIAL OPERATIONAL NEED and report back to the Governing Board with any recommendations.

Also stated in the Resolution is a commitment by staff to provide the Governing Board annual status reports on overall industry performance, which will include a summary of the emissions by year, by refinery. As with all AQMD rules, staff will review this and other information to appropriately develop and recommend future amendments to this rule.

Comment 143: The attached letter from the Western States Petroleum Association was received at the end of the comment period. Staff will be prepared to respond to these comments at the Public Hearing.
October 25, 2005

Saundra McDaniel
Clerk of the Boards
South Coast Air Quality Management District
21865 Copley Drive
Diamond Bar, California 91765-4178

RE: Comments of the Western States Petroleum Association on Proposed Amended Rule 1118, Control of Emissions from Refinery Flares

Dear Ms. McDaniel:

The Western States Petroleum Association (WSPA) is a non-profit trade association representing nearly 30 companies that explore for, produce, refine, transport and market petroleum, petroleum products and natural gas in California and five other western states. Six WSPA members operate petroleum refineries in the South Coast Air Basin, and will be directly affected by the proposed amended rule. As a result, WSPA and its member companies have a direct and substantial interest in this matter.

WSPA has been an active participant with District Staff in commenting on and providing input to the development of Proposed Amended Rule 1118, currently scheduled for consideration by the Governing Board on November 4, 2005. We have worked diligently with the Executive Officer and Staff to develop a rule that attempts to meet the District’s objective of continuing to reduce emissions from flaring, without compromising safe and reliable refinery operations.

We are providing this comment letter to facilitate your review of some important issues that are raised by the current rule language. WSPA will also be presenting oral testimony at the hearing and may provide additional written material at that time.

Summary

Flares are essential refinery safety devices whose operations must not be impaired or compromised. In order for flares to operate safely, they must be available for use and employed when necessary, without restrictions or reservations, particularly when hesitation might create safety issues.
Any constraints on using refinery flares for immediate, necessary pressure relief can result in overpressure of equipment and other potentially dangerous operational situations. Events resulting from these situations can cause significant harm to personnel, equipment and the community.

WSHA is concerned that the very low emission limits posed by the rule and the very detailed regulations and consequent penalties will present refinery operators with a difficult paradox – whether to risk contributing to non-compliance with a District Rule by going without hesitation to the flare, as operator training and plant management procedures typically call for, or to risk personnel safety, plant equipment failure and community impacts by delaying action to avoid violating an element of the new rule.

OSHA regulations require operators of refineries to define specific emergency procedures that may require the refinery operator to purposely-direct gases to the flare to relieve excess pressure in refinery operating equipment.

Although WSHA believes the District Staff is sincere in its stated intent not to create unintended safety issues through adoption and implementation of PAR 1118, we are deeply concerned that the amended rule as currently proposed can affect safe operations. PAR1118 needs to be reviewed to ensure that it is consistent with applicable OSHA standards governing refinery operations - we need time to work these details out with staff.

Background

Rule 1118 (originally titled "Emissions from Refinery Flares") was adopted in 1998 and required refineries to install sampling systems and flow-monitoring instruments – a relatively new technology, not previously available – on their respective flares. Since installation, these monitoring instruments have provided refineries with a "tool" to measure and manage their respective flare operations.

The resulting management controls\(^1\) enabled the industry to reduce reported emissions of sulfur dioxide (SO\(_2\))\(^2\) each successive year since the start of the monitoring program in CY 2000. As District staff will show, the industry emitted an estimated 7.2 tons/day in 2000. Yet by 2004, the latest full year that data are available, those emissions had dropped by over 87% to 0.96 tons/day.

These dramatic emission reductions were achieved by facilities on the basis that there was both an environmental and economic benefit to reducing emissions – and occurred without regulation. There is reason to believe that proven economic interests and clean air benefits will continue to be strong drivers for refineries to keep flare emissions at these low levels. However, actual flare

\(^1\) In some cases additional equipment was also installed.
\(^2\) Sulfur dioxide is referred to herein because it is the pollutant on which PAR 1118 is focused.
emissions may vary from year to year as a function of various factors (e.g., maintenance and turnaround schedules, emergencies etc.).

After the Board directed staff (in September 2004) to develop a flare control rule, WSPA discussed with many Board Members and Assistants our intent to work in a more cooperative and collegial approach to rulemaking. And, we have done just that.

The intent was to achieve consensus on a rule that would essentially have two primary goals: allow the District to obtain SIP-credit for the emissions reductions already achieved by the refineries; and, take reasonable steps designed to continue those reductions.

Improved Communication During Regulatory Process

Because of dedicated efforts by WSPA, the Executive Officer and District Staff, a more cooperative process has resulted in improved communication. WSPA and the District may at times not agree with each other’s viewpoints – but, as a result of the improved dialogue, we both understand better why these differences exist and can focus our collective energies on possible solutions.

Accordingly, many issues have been resolved – and thus will not be discussed in this letter. However, WSPA does have several remaining issues. In fact, some of the unresolved issues were identified at the outset of the rulemaking, as issues that needed to be addressed, and despite best efforts from all parties, remain unresolved. We have shared them with the Executive Officer and the Staff, who have been receptive to our concerns although we clearly still do not agree on how to resolve every one of them.

Issue: Rule definitions, requirements, procedures

WSPA has concerns with the proposed rule, but those concerns stem primarily from the nature of flare operations – flares are both safety and emission control devices, and the need to use them often cannot be predicted by the refineries. Some of our most serious concerns with the rule, and our recommendations to address those concerns, follow:

- **Missing Data Provision/Data Substitution Procedures** - These procedures are required if a refinery cannot obtain data during a flare event. Although vent gas flow monitors are quite reliable, like all equipment, they do have periodic outages and maintenance requirements. While these procedures raise a number of issues, at a minimum, a provision linking missing data provisions to emissions from previous similar events is needed.

Further, we understand that the rule will require the installation of continuous analyzers for vent gas sulfur content and higher heating value, and there may be some additional time

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3 The frequency and scheduling of turnarounds is determined by each refinery depending upon its needs; however, industry-wide data indicates decreased throughout the entire five-year period — no patterns of cyclical emissions have been seen.

4 Because neither sulfur nor higher heating value analyzers have ever been utilized for refinery flare gas service, WSPA has proposed pilot projects to assess the viability of these analyzers. Candidate sites for these pilot projects

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3
when data cannot be obtained. Although the District has included a provision for a refinery to estimate emissions by other means (e.g., process data, engineering knowledge, etc.), these provisions need clarification.

**Recommendation:** We have suggested that the rule should cite use of engineering judgment to include reference to previous events from the same or similar pieces of equipment. Allowing use of past data will provide a better and more precise estimate of actual emissions than using maximum theoretical values. Implementation of this recommendation will greatly reduce the chances for overestimation of emissions and imposition of mitigation fees, while still improving the District's ability to address community concerns.

- **Essential Operational Needs (EONs)** - Although we believe the staff recognizes both that refinery operations are complex, and that flares serve as emission control devices (per federal and local rules), the proposed definition of EONs does not and cannot cover the entire range of legitimate and "essential" needs. This could impact proven refinery safety and operating practices. Given the complexity of refineries, and the variability in refinery operations, the EON definition should, at a minimum, be revised to recognize that there are a number of situations that cannot be anticipated or adequately described within the strict definition of the term.

- **Process Upsets** - PAR 1118 recognizes that emergencies can occur, and that they may result in the need to flare vent gas. However, PAR 1118 ties "emergencies" to an equipment failure (as well as to natural disasters, utility power outages, or acts of war, etc.). WSPA believes that process upsets (conditions which are recognized in Federal definitions — e.g., "the failure of a process to operate in a normal manner") must also be included in the definition of "emergency".

Staff has partially addressed WSPA's concern by including very limited language under EONs. We have responded by sharing additional insights about refinery operations and process upsets with them, and we are looking forward to better resolution of the issue.

- **Clean Up Additional Rule Provisions** - There is need for a continuing effort to clean up additional rule provisions, including definitions, practical operations limits, etc. WSPA members do not have a clear understanding of some rule language.

For example, the rule appears to require in Flare Management Plans (1118(c)(1)(C)(ii)) "excess gas storage" - implying that there is a need for a refinery to have that capability. However, storing fuel gas has operations and permitting implications and for some refineries, is a provision that is not operationally practical.

**Recommendation for all three concerns above:** Given that new regulatory language cannot be crafted in such a short time to address these complex issues, implement a break-in/look-back period where definitions, conditions, and details are defined so that a mutual understanding exists. This period could be anywhere from 1 to 2 years, and

have been identified. WSPA expects that a requirement to install these analyzers will be dependent upon a successful outcome of the respective pilot projects.
would allow all interested parties to understand the scope, implications and impacts of the rule. This implementation/look back period would also allow a comparison of the rule’s actual impact with its original intent.

**Conclusion**

WSPA has been working cooperatively with the District on this rule and recognizes the District’s intent to claim SIP-credit for the significant reductions that the refineries have already achieved. However, the requirements of the proposed rule are complex, and some are untested in refinery applications.

Some additional implementation/shakedown period is needed to develop a better understanding of rule requirements, and reach mutual agreement on certain definitions and requirements. In addition, the 2012 emissions limit of 0.5 tons of SO2 per million barrels of crude capacity is very aggressive, and may have unintended consequences on refinery safety and product supply and distribution. It should not be reduced further.

Inclusion of the recommendations noted in this letter would greatly improve ultimate rule effectiveness and help the District achieve its targeted emission reductions.

We are prepared to continue working with the District’s Executive Officer and Staff to achieve targeted reductions in flare emissions without compromising the safety of our refinery operations and personnel, and the communities around our facilities.

Sincerely,

![Signature]

Cc: Barry Wallerstein, Executive Officer, SCAQMD

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Proposed Amended Rule 1118  
IX-46  
October 2005
APPENDIX A

REFERENCES
APPENDIX A – REFERENCES

Staff Report for Rule 1118 – Emissions From Refinery Flares, SCAQMD, December 1997

Evaluation of Refinery Flare Emissions at Petroleum Refineries, SCAQMD, September 2004


U.S. EPA, Petroleum Refinery Initiative

U.S. EPA Enforcement Alert, Volume 3, Number 9 EPA300-N-00-014, October 2000


Hydrocarbon Processing, August 2002, pp76 – 80

Oil and Gas Journal, November 23, 1992, pp 70-76

Oil and Gas Journal, December 7, 1992, pp 68-72

Chevron Texaco Letter to William Norton, BAAQMD, February 6, 20030
APPENDIX B

CALIFORNIA AIR RESOURCES BOARD RESOLUTION 86-60
WHEREAS, Health and Safety Code Section 42701 requires the Air Resources Board (the "Board") to determine the availability, technological feasibility, and economic reasonableness of monitoring devices to measure and record continuously emissions from larger stationary sources, and Section 42702 requires the Board to specify the types of stationary sources, the processes, and the contaminants for which a monitoring device is available, technologically feasible, and economically reasonable;

WHEREAS, pursuant to the Board's direction following consideration of a 1984 petition from Citizens for a Better Environment ("CBE"), the staff has evaluated the availability, technological feasibility and economic reasonableness of continuous emission monitors for oil refinery flares;

WHEREAS, based on its evaluation the staff has recommended that the Board determine that devices which monitor the on/off status of refinery flares are technologically feasible, available, and economically reasonable;

WHEREAS, the Board staff has further recommended that the Board:

Encourage local air pollution control districts in which refinery flares are located to adopt rules requiring refiners to install refinery flare on/off monitors;

Direct the staff to work, as necessary, with industry and the districts to develop rules requiring the use of these devices with workable but standardized definitions of "on" and "off";

Encourage the districts to require, pursuant to Health and Safety Code Section 42303, refiners to provide grab sample composition analyses of flare feed stream gases;

Direct the staff, after sufficient on/off data and coordinated composition data have been collected, to evaluate such data and develop recommendations regarding the development of a Suggested Control Measure for the control of refinery flare emissions if the staff's evaluation indicates that such control is reasonable;

WHEREAS, pursuant to Health and Safety Code Sections 39002 and 40000, the districts have the primary responsibility in California for control of air pollution from nonvehicular sources;

WHEREAS, Health and Safety Code Section 41511 authorizes a district, for the purpose of carrying out its duties, to adopt rules requiring the owner or operator of any emission source to take such action, including installation of continuous emission monitors, as the district finds to be reasonable for determining the amount of emissions from the source;
WHEREAS, Health and Safety Code Section 43203 authorizes a district air pollution control officer at any time to require from a permit holder information which will disclose the nature, extent, quantity, or degree of air contaminants which are discharged by the source for which the permit was granted;

WHEREAS, the California Environmental Quality Act and Board regulations require that no project having significant adverse environmental impacts be adopted as originally proposed if feasible alternatives or mitigation measures are available;

WHEREAS, the Board finds that:

Pressure sensors, optical radiation sensors, and hot wire thermistors have been used at refineries in California to monitor the on/off status of refinery flares to the satisfaction of refinery personnel;

Refinery flare on/off status monitors are presently available in California from commercial vendors and would cost approximately $800 to $2000 for each installation;

Emissions of oxides of nitrogen and oxides of sulfur from refinery flares are currently not being routinely monitored in California, and the magnitude of flare emissions has not been determined accurately because of the technical problems associated with flare emission monitoring;

Records of the frequency and duration of flare operations made by flare on/off monitoring devices, coupled with composition data from analysis of grab samples of refinery flare gas streams, can be combined with existing information about refinery processes and flares to yield improved emissions estimates;

Standardized definitions of "on" and "off" for refinery flare on/off status monitors would enhance the usefulness of the data from such monitors;

The actions recommended by the staff will have no adverse environmental impact;

WHEREAS, the Board has conducted a public meeting to consider the staff recommendations and has received and considered written and oral presentations from any members of the public wishing to comment.

NOW, THEREFORE, BE IT RESOLVED that the Board determines that monitoring devices are technologically feasible, available, and economically reasonable to identify and record continuously the on/off status of refinery flares for the purpose of determining refinery flare emissions.

BE IT FURTHER RESOLVED that the Board encourages local air pollution control districts in which refinery flares are located to adopt rules requiring refiners to install refinery flare on/off monitors.
BE IT FURTHER RESOLVED that the Board directs the staff to work, as necessary, with industry and the districts to develop rules requiring the use of these devices with workable but standardized definitions of "on" and "off."

BE IT FURTHER RESOLVED that the Board encourages districts to require, pursuant to Health and Safety Code Section 42303, refiners to provide grab sample composition analyses of flare feed stream gases.

BE IT FURTHER RESOLVED that the Board directs the staff to report to the Board in six months on the progress of the districts in developing and adopting rules requiring refiners to use on/off status flare monitors and to submit grab sample composition analyses of flare feed stream gases, and directs the staff to report thereafter as appropriate on the implementation and results of flare monitoring requirements.

BE IT FURTHER RESOLVED that the Board directs the staff, after sufficient on/off data and coordinated composition data have been collected, to evaluate such data and develop recommendations regarding the development of a Suggested Control Measure for the control of refinery flare emissions if the staff's evaluation indicates that such control is reasonable.

I hereby certify that the above is a true and correct copy of Resolution 86-60, as adopted by the Air Resources Board.

[Signature]
HAROLD HOLMES, Board Secretary
REGULATION 12
MISCELLANEOUS STANDARDS OF PERFORMANCE
RULE 11
FLARE MONITORING AT PETROLEUM REFINERIES

INDEX

12-11-100 GENERAL
12-11-101 Description
12-11-110 Exemption, Organic Liquid Storage and Distribution
12-11-111 Exemption, Marine Vessel Loading Terminals
12-11-112 Exemption, Wastewater Treatment Plants
12-11-113 Exemption, Pumps
12-11-114 Limited Exemption, Total Hydrocarbon and Methane Composition Monitoring and Reporting

12-11-200 DEFINITIONS
12-11-201 Flare
12-11-202 Flare Monitoring System
12-11-203 Flaring
12-11-204 Gas
12-11-205 Petroleum Refinery
12-11-206 Pilot Gas
12-11-207 Purge Gas
12-11-208 Sulfur Recovery Plant
12-11-209 Thermal Oxidizer
12-11-210 Vent Gas

12-11-400 ADMINISTRATIVE REQUIREMENTS
12-11-401 Flare Data Reporting Requirements
12-11-402 Semi-Annual Flow Verification Report

12-11-500 MONITORING AND RECORDS
12-11-501 Vent Gas Flow Monitoring
12-11-502 Vent Gas Composition Monitoring
12-11-503 Ignition Monitoring
12-11-504 Pilot and Purge Gas Monitoring
12-11-505 Recordkeeping Requirements
12-11-506 General Monitoring Requirements
12-11-507 Video Monitoring

12-11-600 MANUAL OF PROCEDURES
12-11-601 Testing, Sampling, and Analytical Methods
12-11-602 Flow Verification Test Methods
REGULATION 12
MISCELLANEOUS STANDARDS OF PERFORMANCE
RULE 11
FLARE MONITORING AT PETROLEUM REFINERIES
(Adopted June 4, 2003)

12-11-100 GENERAL

12-11-101 Description: The purpose of this rule is to require monitoring and recording of emission data for flares at petroleum refineries.

12-11-110 Exemption, Organic Liquid Storage and Distribution: The provisions of this rule shall not apply to flares or thermal oxidizers used to control emissions exclusively from organic liquid storage vessels subject to Regulation 8, Rule 5 or exclusively from loading racks subject to Regulation 8 Rules 6, 33, or 39.

12-11-111 Exemption, Marine Vessel Loading Terminals: The provisions of this rule shall not apply to flares or thermal oxidizers used to control emissions exclusively from marine vessel loading terminals subject to Regulation 8, Rule 44.

12-11-112 Exemption, Wastewater Treatment Systems: The provisions of this rule shall not apply to thermal oxidizers used to control emissions exclusively from wastewater treatment systems subject to Regulation 8, Rule 8.

12-11-113 Exemption, Pumps: The provisions of this rule shall not apply to thermal oxidizers used to control emissions exclusively from pump seals subject to Regulation 8, Rule 18. This exemption does not apply when emissions from a pump are routed to a flare header.

12-11-114 Limited Exemption, Total Hydrocarbon and Methane Composition Monitoring and Reporting: The provisions of Sections 12-11-401.2, 401.3, 401.5, 502.2 and 502.3 that require monitoring and reporting of total hydrocarbon and methane composition shall not apply to a flare that exclusively burns flexicoker gas with or without supplemental natural gas, provided that the owner or operator demonstrates by weekly sampling and analysis, verified by the APCO, that the methane content and the non-methane content of the vent gas flared are less than 2 percent and 1 percent by volume, respectively.

12-11-200 DEFINITIONS

12-11-201 Flare: A combustion device that uses an open flame to burn combustible gases with combustion air provided by uncontrolled ambient air around the flame. Flares may be either continuous or intermittent and are not equipped with devices for fuel-air mix control or for temperature control. This term includes both ground and elevated flares.

12-11-202 Flare Monitoring System: All sample systems, transducers, transmitters, data acquisition equipment, data recording equipment, video monitoring equipment, and video recording equipment involved in flare monitoring.

12-11-203 Flaring: A high-temperature combustion process used to burn vent gases.

12-11-204 Gas: The state of matter that has neither independent shape nor volume, but tends to expand indefinitely. For the purposes of this rule, “gas” includes aerosols and the terms “gas” and “gases” are interchangeable.

12-11-205 Petroleum Refinery: A facility that processes petroleum, as defined in the North American Industrial Classification Standard No. 32411, and including any associated sulfur recovery plant.

12-11-206 Pilot Gas: The gas used to maintain the presence of a flame for ignition of vent gases.

12-11-207 Purge Gas: The gas used to prevent air backflow in the flare system when there is no vent gas.
12-11-208 **Sulfur Recovery Plant:** A process unit that processes sulfur and ammonia containing material and produces a final product of elemental sulfur.

12-11-209 **Thermal Oxidizer:** An enclosed or partially enclosed combustion device that is used to oxidize combustible gases, that generally comes equipped with controls for combustion chamber temperature and often with controls for air/fuel mixture, and that exhausts all combustion products through a vent, duct, or stack so that emissions can be measured directly.

12-11-210 **Vent Gas:** Any gas directed to a flare excluding assisting air or steam, flare pilot gas, and any continuous purge gases.

12-11-400 **ADMINISTRATIVE REQUIREMENTS**

12-11-401 **Flare Data Reporting Requirements:** The owner or operator of a flare shall submit a monthly report to the APCO on or before 30 days after the end of each month for each flare subject to this rule. Only one report is required for a staged or cascading flare system if all flares in the system serve the same header or headers. The report shall be in an electronic format approved by the APCO. Each monthly report shall include all of the following:

401.1 The total volumetric flow of vent gas in standard cubic feet for each day and for the month, and, effective for the first full month after the commencement of the monitoring required by Section 12-11-501, for each hour of the month.

401.2 If vent gas composition is monitored using sampling or integrated sampling, total hydrocarbon content as propane by volume, methane content by volume, and, hydrogen sulfide content by volume, for each sample or integrated sample required by Section 12-11-502. If the content of any additional compound or compounds is determined by the analysis of a sample or integrated sample, the content by volume of each additional compound.

401.3 If vent gas composition is monitored by a continuous analyzer or analyzers pursuant to Section 12-11-502, average total hydrocarbon content as propane by volume, average methane content by volume, and, depending upon the analytical method used pursuant to Section 12-11-601, total reduced sulfur content by volume or hydrogen sulfide content by volume of vent gas flared for each hour of the month. If the content of any additional compound or compounds is determined by the continuous analyzer or analyzers, the average content by volume for each additional compound for each hour of the month.

401.4 If the flow monitor installed pursuant to Section 12-11-501 measures molecular weight, the average molecular weight for each hour of the month.

401.5 For any pilot and purge gas used, the type of gas used, the volumetric flow for each day and for the month, and the means used to determine flow.

401.6 For any 24-hour period during which more than 1 million standard cubic feet of vent gas was flared, a description of the flaring including the cause, time of occurrence and duration, the source or equipment from which the vent gas originated, and any measures taken to reduce or eliminate flaring.

401.7 Flare monitoring system downtime periods, including dates and times.

401.8 The archive of images recorded for the month pursuant to Section 12-11-507.

401.9 For each day and for the month provide calculated methane, non-methane and sulfur dioxide emissions. For the purposes of emission calculations only, a flare control efficiency of 98 percent shall be used for hydrocarbon flares, and a flare control efficiency of 93 percent shall be used for flexi-gas flares or if, based on the composition analysis specified in Section 12-11-502, the calculated lower heating value of the vent gas is less than 300 British Thermal Units/Standard Cubic Foot (BTU/SCF).
**12-11-402 Flow Verification Report:** Effective twelve months after adoption of this rule and every six months thereafter, the owner or operator of a flare shall submit a flow verification report to the APCO for each flare subject to the rule. The flow verification report shall be included in the corresponding monthly report required by Section 12-11-401. Only one report is required for a staged or cascading flare system if all flares in the system serve the same header or headers. The report shall compare flow as measured by the flow monitoring equipment required by Section 12-11-501 and a flow verification pursuant to Section 12-11-602 for the same period or periods of time. The owner or operator shall demonstrate that the flow verification was performed using good engineering practices. If there are no flaring events as described in Section 12-11-401.6 during the preceding six-month period, a flow verification report is not required for that period.

**12-11-500 MONITORING AND RECORDS**

**12-11-501 Vent Gas Flow Monitoring:** Effective 180 days after adoption of this rule, the owner or operator of a petroleum refinery shall not operate a flare unless vent gas to the flare is continuously monitored for volumetric flow by a device that meets the following requirements:

1.1 The minimum detectible velocity shall be 0.1 foot per second.

1.2 The device shall continuously measure the range of flow rates corresponding to velocities from 0.5 to 275 feet per second in the header in which the device is installed.

1.3 The device shall have a manufacturer’s specified accuracy of ±5% over the range of 1 to 275 feet per second.

1.4 The device shall be installed at a location where measured volumetric flow is representative of flow to the flare or to the flare system in the case of a staged or cascading flare system consisting of more than one flare.

1.5 Effective 180 days after adoption of this rule, the owner or operator shall provide access for the APCO to verify proper installation and operation of the flare monitoring system.

1.6 Effective 18 months after adoption of this rule, the flow monitoring system shall be maintained to be accurate to within ±20% as demonstrated by the flow verification report specified in Section 12-11-402.

**12-11-502 Vent Gas Composition Monitoring:** The owner or operator of a petroleum refinery shall not operate a flare unless the following requirements are met:

1. Requirements applicable to all vent gas composition monitoring:

   1.1 Vent gas monitored for composition, whether by sampling, integrated sampling or continuous monitoring, shall be taken from a location at which samples are representative of vent gas composition. If flares share a common header, a sample from the header will be deemed representative of vent gas composition for all flares served by the header.

   1.2 Effective 90 days after the adoption of this rule, the monitoring system shall provide access for the APCO to collect vent gas samples to verify the analyses required by Section 12-11-502.

2. Effective 90 days after adoption of this rule and until the requirements of Section 12-11-502.3 are met, the owner or operator shall monitor vent gas composition through sampling that meets the following requirements:

   2.1 For each day on which flaring occurs, one sample shall be taken within 30 minutes of the commencement of flaring.

   2.2 Samples may be taken from the flare header or from an alternate location at which samples are representative of vent gas composition.

   2.3 Samples shall be analyzed pursuant to Section 12-11-601.

3. Effective 270 days after adoption of this rule, the owner or operator shall monitor vent gas composition using one of the following four methods:
3.1 Sampling that meets the following requirements:
   a. If the flow rate of vent gas flared in any consecutive 15-minute period continuously exceeds 330 standard cubic feet per minute (SCFM), a sample shall be taken within 15 minutes, except that, for flares exclusively serving sulfur or ammonia plants, a sample shall be taken within 1 hour or composition data representing worst-case conditions shall be provided by the owner or operator and verified by the APCO. The sampling frequency thereafter shall be one sample every three hours and shall continue until the flow rate of vent gas flared in any consecutive 15-minute period is continuously 330 SCFM or less. In no case shall a sample be required more frequently than once every 3 hours.
   b. Samples shall be analyzed pursuant to Section 12-11-601.

3.2 Integrated sampling that meets the following requirements:
   a. If the flow rate of vent gas flared in any consecutive 15 minute period continuously exceeds 330 standard cubic feet per minute (SCFM), integrated sampling shall begin within 15 minutes and shall continue until the flow rate of vent gas flared in any consecutive 15 minute period is continuously 330 SCFM or less.
   b. Integrated sampling shall consist of a minimum of one aliquot for each 15-minute period until the sample container is full. If sampling is still required pursuant to Section 12-11-502.3.2a, a new sample container shall be placed in service within one hour after the previous container was filled. A sample container shall not be used for a sampling period that exceeds 24 hours.
   c. Samples shall be analyzed pursuant to Section 12-11-601.

3.3 Continuous analyzers that meet the following requirements:
   a. The analyzers shall continuously monitor for total hydrocarbon, methane, and, depending upon the analytical method used pursuant to Section 12-11-601, hydrogen sulfide or total reduced sulfur.
   b. The hydrocarbon analyzer shall have a full-scale range of 100% total hydrocarbon.
   c. Each analyzer shall be maintained to be accurate to within 20% when compared to any field accuracy tests or to within 5% of full scale.

3.4 A continuous analyzer employing gas chromatography that meets the following requirements:
   a. The gas chromatography system shall monitor for total hydrocarbon, methane, and hydrogen sulfide.
   b. The gas chromatography system shall be maintained to be accurate to within 5% of full scale.

12-11-503 Pilot Monitoring: Any flare subject to this rule must be equipped and operated with an automatic igniter or a continuous burning pilot, which must be maintained in good working order. If a pilot flame is employed, the flame shall be monitored with a device to detect the presence of the pilot flame. If an electric arc ignition system is employed, the system shall pulse on detection of loss of pilot flame and until the pilot flame is reestablished.

12-11-504 Pilot and Purge Gas Monitoring: The owner or operator of a petroleum refinery shall not operate a flare unless (1) volumetric flows of purge and pilot gases are monitored by flow measuring devices, or (2) other parameters are monitored so that volumetric flows of pilot and purge gas may be calculated based on pilot design and the parameters monitored.

12-11-505 Recordkeeping Requirements: Except as provided in Section 12-11-507, the owner or operator of a flare shall maintain records for all the information required to
be monitored for a period of five years and make such records available to the APCO upon request.

12-11-506 General Monitoring Requirements: Persons responsible for monitoring subject to this rule shall comply with the following:

506.1 Periods of flare monitoring system inoperation greater than 24 continuous hours shall be reported by the following working day, followed by notification of resumption of monitoring. Adequate proof of expeditious repair shall be furnished to the APCO for downtime in excess of fifteen consecutive days. Periods of inoperation of the vent gas flow monitoring required by Section 12-11-501 shall not exceed 30 days per calendar year. Periods of inoperation of vent gas composition monitoring specified in Sections 12-11-502.3.2 (integrated sampling) and 12-11-502.3.4 (gas chromatography) shall not exceed 30 days per calendar year. Effective 450 days after the adoption of this rule, periods of inoperation of the vent gas composition monitoring specified in Section 12-11-502.3.3 (continuous analyzers) shall not exceed 30 days per calendar year per analyzer. Periods of inoperation of video monitoring specified in Section 12-11-507 shall not exceed 30 days per calendar year.

506.2 During periods of inoperation of continuous analyzers or auto-samplers installed pursuant to Section 12-11-502, persons responsible for monitoring shall take samples as required by Section 12-11-502.2.1. During periods of inoperation of flow monitors required by Section 12-11-501, flow shall be calculated using good engineering practices.

506.3 The person(s) responsible for monitors subject to this rule shall maintain and calibrate all required monitors and recording devices in accordance with the applicable manufacturer’s specifications. In order to claim that a manufacturer’s specification is not applicable, the person responsible for emissions must have, and follow, a written maintenance policy that was developed for the device in question. The written policy must explain and justify the difference between the written procedure and the manufacturer’s procedure.

506.4 Data Recording System: All in-line continuous analyzer and flow monitoring data must be continuously recorded by an electronic data acquisition system capable of one-minute averages. Flow monitoring data shall be recorded as one-minute averages.

12-11-507 Video Monitoring: For each flare equipped with video monitoring capability as of January 1, 2003, the owner or operator of a flare subject to this rule shall, effective 180 days after adoption of this rule, install and maintain equipment that records a real-time digital image of the flare and flame at a frame rate of no less than 1 frame per minute. The recorded image of the flare shall be of sufficient size, contrast, and resolution to be readily apparent in the overall image or frame. The image shall include an embedded date and time stamp. The equipment shall archive the images for each 24-hour period. Effective 180 days after adoption of this rule, for any flare for which the report required by Section 12-11-401 shows that more than 1 million standard cubic feet of vent gas was flared in any 24-hour period, the owner or operator of the flare shall, within 90 days after the end of the month covered by the report, meet the same requirements as those imposed by this Section for flares with existing video monitoring capability.

12-11-600 MANUAL OF PROCEDURES

12-11-601 Testing, Sampling, and Analytical Methods:

601.1 Samples and integrated samples shall be analyzed using the following test methods, or latest revision, where applicable:
1.1 Total hydrocarbon content and methane content of vent gas shall be determined using ASTM Method D1945-96, ASTM Method UOP 539-97, or EPA Method 18.

1.2 Hydrogen sulfide content of vent gas shall be determined using ASTM Method D1945-96 or ASTM Method UOP 539-97.

1.3 Any alternative method to the above methods if approved by the APCO and EPA.

601.2 Except as provided in Section 12-11-601.3, if vent gas composition is monitored using continuous analyzers, the analyzers shall employ the following methods, or latest revision, where applicable:

2.1 Total hydrocarbon content and methane content of vent gas shall be determined using EPA Method 25A or 25B.

2.2 Total reduced sulfur content of vent gas shall be determined using ASTM Method D4468-85.

2.3 Hydrogen sulfide content shall be determined using ASTM Method D4084-94.

2.4 Any alternative method to the above methods if approved by the APCO and EPA.

601.3 If vent gas composition is monitored with a continuous analyzer employing gas chromatography, the following requirements shall be met:

3.1 ASTM Method D1945-96 or latest revision, or ASTM Method UOP 539-97 or latest revision shall be used.

3.2 The system shall analyze samples for total hydrocarbon content, methane content, and hydrogen sulfide content.

3.3 The minimum sampling frequency shall be one sample every 30 minutes.

3.4 Any alternative method to the above methods if approved by the APCO and EPA.

12-11-602 Flow Verification Test Methods: For purposes of the semi-annual verification required by Section 12-11-402, vent gas flow shall be determined using one or more of the following methods:

602.1 District Manual of Procedures, Volume IV, ST-17 and ST-18;

602.2 EPA Methods 1 and 2;

602.3 Other flow monitoring devices or process monitors.

602.4 Any verification method recommended by the manufacturer of the flow monitoring equipment installed pursuant to Section 12-11-501.

602.5 Tracer gas dilution or velocity.

602.6 Any alternative method approved by the APCO and EPA.
Proposed
Regulation 12, Rule 11:
Flare Monitoring at Petroleum Refineries

Staff Report

May 2003
(Revised 5/27/03)

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# TABLE OF CONTENTS

EXECUTIVE SUMMARY

BACKGROUND
FLARES AND SIMILAR DEVICES
FLARE DESIGN AND OPERATION
EMISSIONS FROM FLARES
BAY AREA FLARES AND EXISTING MONITORING EQUIPMENT
FLOW MONITORING TECHNOLOGIES
GAS COMPOSITION MONITORING
HISTORY OF MONITORING
CALIFORNIA AIR DISTRICT REGULATIONS
PROPOSED RULE
EXEMPTIONS
DEFINITIONS
ADMINISTRATIVE REQUIREMENTS
MONITORING AND RECORDS
MANUAL OF PROCEDURES
EMISSIONS REDUCTIONS
ECONOMIC IMPACTS
COSTS
SOCIOECONOMIC IMPACTS
INCREMENTAL COSTS
ENVIRONMENTAL IMPACTS
REGULATORY IMPACTS
FEDERAL REQUIREMENTS
DISTRICT REQUIREMENTS
RULE DEVELOPMENT HISTORY
DISTRICT STAFF IMPACTS
CONCLUSION
REFERENCES
COMMENTS AND RESPONSES
EXECUTIVE SUMMARY

Proposed District Regulation 12, Rule 11: Flare Monitoring at Petroleum Refineries is intended to implement control measure SS-15 from the Bay Area 2001 Ozone Attainment Plan. This new rule would require refineries to monitor the volume and composition of gases burned in refinery flares, to calculate flare emissions based on this data, to determine the reasons for flaring, to report all of this information to the District, and to provide video monitoring of flares. The rule will lead to much more accurate estimates of flare emissions, will allow the District to refine its emission inventory for flaring, and will provide information that is likely to lead to reductions in flaring.

Flares are primarily intended as safety and pollution control devices. They burn gases that cannot be used by the refinery and prevent their direct release to the atmosphere. The proposed rule would require the monitoring of these gases. The primary parameters to be monitored are vent gas flow to the flare and vent gas composition.

For monitoring of the volume of gas directed to flares, the rule establishes range and accuracy requirements that, at present, can be met only by ultrasonic flow monitors. These monitors are called time-of-flight (TOF) ultrasonic monitors. They determine flow velocity by measuring the time required for ultrasonic waves to travel in the flare gas from an "upstream" probe to a "downstream" probe and by comparing the time to that required for the slower "upstream" trip. This technology is the best available technology for measuring gas flow for flares. Two of the Bay Area refineries already have older ultrasonic monitors, but the rule would require all of the refineries to install newer, more sophisticated, and more accurate monitors.

For monitoring of flare gas composition, the rule allows two primary options: (1) collection of samples for subsequent lab analysis, or (2) use of continuous analyzers that sample gas and analyze it automatically. For the first option, samples can be collected with an auto-sampler or manually. Manual sampling is expected to be limited to infrequently used flares. For the second option, a number of continuous analyzer technologies are available: flame ionization detectors (FID), non-dispersive infrared (NDIR) spectrophotometry, and gas chromatography (GC). These methods are widely used by industry and by regulators, but have never been used on flare headers. The rule establishes appropriate methods and procedures for each technology.

The rule allows the two options, sampling and continuous analyzers, because each has advantages and disadvantages that may dictate one over the other for the specific flare in question. Sampling is a proven approach that will, over time, build a large set of data for each flare for which it is used. Continuous analyzers, though desirable because of the continuous data they can provide, have not yet been used to monitor flare vent gas, which is not as "clean" as most gas streams for which these analyzers are used. Use of continuous analyzers will require sample conditioning equipment that may be difficult to design and may require considerable maintenance. The rule represents a compromise, allowing a method that is known to work (sampling) while encouraging a method that the District would like to see proven in practice (continuous analyzers). This ensures that the rule will work and avoids the risk of rule failure that would come from mandating only continuous analyzers and the missed opportunity that
might come from mandating only sampling. District staff expects that the result may be the use of continuous analyzers on some flares and sampling on others.

The proposed rule requires monitoring data to be submitted to the District in a monthly report that is due within 30 days after the end of each month. The report must include flow data, composition data, emissions estimates, descriptions of all flaring activity, and information on any downtime for the monitors, and the archive of video images recorded for the month. The rule also requires a semi-annual report comparing flow monitor data for a period of time with a set of data for the same period derived by other methods. The comparison data can come from methods approved by the monitor manufacturer, from flow volume or velocity measurements using tracer gases, from flow measurements with pitot tubes, or from data derived from other methods approved by the District.

The proposed rule also requires video monitoring of flares. The flare image is required to be recorded, and the recorded images for each month must be submitted with the monthly report. This will allow the District to examine flare imagery to help explain any flaring, to respond to any community concerns or complaints, and to ensure that monitor data corresponds with the images.

The rule requirements would be imposed in steps that are based upon the District's determination about the length of time required to install the necessary equipment. All refineries would have to start taking daily composition samples within 3 months (some are already doing so). Within 6 months, each refinery will have to have continuous flow monitors in place. In 9 months, each refinery will be required to monitor composition at more frequent intervals using sampling or continuous analyzers.

The proposed rule would apply to the 25 flares located at the five Bay Area refineries: ChevronTexaco in Richmond (9 flares), ConocoPhillips in Rodeo (2 flares), Valero in Benicia (3 flares), Tesoro in Avon (6 flares), and Shell in Martinez (5 flares). Two of the twenty-five are not in service. All of the flares in service are currently monitored for some parameter, typically flow or vent gas heating value. The proposed rule would require that all of the refineries upgrade their current monitoring equipment, but the new equipment necessary and the costs involved would vary greatly, depending upon the sophistication of the currently-installed equipment. The District has estimated a range of costs for a refinery based on costs for the various options allowed under the proposed rule. The cost of the monitoring equipment for a single flare is roughly $200,000. The District has estimated the annual cost per flare, with equipment costs amortized over ten years and including operating and maintenance costs, to be $50,000 per flare per year.

In developing this rule, the District relied on information and data gathered during the District's flare further study effort. In August 2002, District staff held a workshop in Martinez to discuss basic rule concepts. It began developing a draft rule in late 2002, and in March shared preliminary drafts with representatives from the five Bay Area refineries, the Western States Petroleum Association (WSPA), and Communities for a Better Environment (CBE). In late March and early April, District staff held three community meetings to discuss detailed rule
concepts. The meetings were held in Richmond, Martinez, and Rodeo. Rule drafts were also shared with ARB and EPA.

After the proposed rule was developed for the May 21st Board hearing, the District convened the flare workgroup that has been working on the District’s flare further study (further study measure FS-8 from the Bay Area 2001 Ozone Attainment Plan) to discuss the proposed rule. Additional issues were identified, and a revised rule is now proposed for adoption by the Board. To avoid confusion, this staff report refers to the rule prepared and made available with the public notice for the May 21st hearing as the “proposed rule.” This is in keeping with standard terminology used by ARB, air districts, and the Health and Safety Code (§§40725, 40726). The revised version of the rule now proposed for adoption is called the “revised rule.” Earlier drafts of the rule are called “earlier drafts.”

At the May 21st Board hearing, a number of additional changes in the revised rule were suggested in comments by WSPA, individual refineries, the Air Resources Board, CBE, and refinery labor unions. In response to those comments, additional changes have been made to the revised rule. These changes are reflected in double underline / double strikethrough format in the revised rule. The revisions are in Sections 12-11-401, 502, 506, and 507. Brief discussions of the changed rule sections have been added to this staff report and are underlined. These changes are not so substantial as to change the meaning of the rule and can be adopted at the June 4, 2003 hearing. The most significant issue raised at the hearing was the issue of "wecasting." Staff is proposing that the wecasting issue be referred to the Stationary Source Committee of the Board because of its difficulty, because it was not included in the rule for which the CEQA document was prepared, and because resolution of webcasting issues could delay the rest of the rule substantially if not treated separately.

Pursuant to the California Environmental Quality Act (CEQA), the District prepared an initial study to determine the potential environmental impacts of proposed Regulation 12, Rule 11. The study identified the construction work required to install monitors as a source of potential environmental impacts. However, because of the safety requirements that govern this type of work, the regularity with which similar hot work is conducted in refineries, and the consequent familiarity with and preparedness for this type of work on the part of refinery workers and contractors, the study concluded that the proposed rule would not result in any significant environmental impacts. The document was circulated for comment, and no comments were received.

**BACKGROUND**

Flares provide a safety and emission control mechanism for refinery blowdown systems. Blowdown systems collect and separate both liquid and gaseous discharges from various refinery process units and equipment. The systems generally recover liquids and send gases to the fuel gas system for use in refinery combustion. However, when the heating value of the gas stream is insufficient, when the stream is intermittent, or when the stream exceeds what is necessary to satisfy refinery combustion needs, flares combust these gases and prevent their direct release to the atmosphere. Flares are designed to handle large fluctuations in the flow rate and hydrocarbon content of gases.
Flares and Similar Devices

A number of different devices may be called flares. A flare, as defined in the proposed rule, is a combustion device that uses an open flame to burn combustible gases with combustion air provided by uncontrolled ambient air surrounding the flame. The term is most commonly applied to the open air flare. It is also commonly applied to ground flares, which are located at ground level and typically have an enclosure around the open flame. The term "enclosed flare" may also be applied to this type of flare, regardless whether it is located at ground level. Flares, whether "open air," "ground," or "enclosed," rely on surrounding air for combustion and do not have any mechanism for control of this combustion air.

The term "thermal oxidizer" is sometimes used as a broad term to apply to many types of devices that oxidize combustible gases, including flares. However, the term is more properly applied to enclosed devices that, unlike flares, control the mixing of combustion air and fuel. As defined in the proposed rule, a thermal oxidizer is an enclosed or partially enclosed combustion device that is used to oxidize combustible gases, that generally comes with controls for combustion temperature and often with controls for air/fuel mixture, and that exhausts all combustion products through a vent, duct, or stack so that emissions can be measured directly.

In general, flares are used to control units and operations from which gas flows may be intermittent and may range from very low flows to very high flows. They are accepted as the most reliable way to ensure that the potentially enormous flows that may result from an upset or shutdown of a large refinery unit, a large block of units, or an entire refinery can be controlled.

Thermal oxidizers are generally used to control emissions from sources or operations for which flows are lower and more stable. These sources include wastewater systems, loading racks, storage vessels, pumps or compressors, and some relief systems on small process units. Because of the greater control over combustion afforded by temperature and mixture controls, thermal oxidizers typically have very high combustion efficiency. Thermal oxidizers are typically subject to permit conditions requiring combustion efficiency of 98% or higher. Because combustion products past through a vent, a duct, or a stack, the combustion efficiency of thermal oxidizers can be verified by source tests.

Flare Design and Operation

The open air flare is the predominant design type in the Bay Area. These flares are designed to handle large fluctuations in the flow rate and hydrocarbon content of gases. They are used to prevent releases of uncombusted materials generated during maintenance activities, emergency events such as power and equipment failures, and to a lesser extent as a control device for materials that cannot be recovered.
Figure 1. Typical Flare System

The diagram above illustrates a typical general service flare system. The system is a component of the refinery blowdown system. The blowdown system is designed to collect gases and liquids released throughout the refinery and direct them to the refinery recovery system or, when there is insufficient capacity to recover them, to a flare. These gases and liquids may be released for many different reasons. They may be normal byproducts of a process unit or vessel, they may result from an upset in a process unit, or they may come from refinery process units during startup and shutdown when the balance between gas generation and the combustion of that gas for process heat is disrupted.

The blowdown system delivers gases and liquids to a knockout drum that captures liquids and directs them to the oil recovery stream. The refinery flare gas compressors then direct gases to the fuel gas system. The extent to which these gases can be captured depends upon the capacity of the compressors. A refinery in good balance should be able to capture most of the gases delivered to the blowdown system during normal operations and use them to heat process units. This is not the case if a refinery has insufficient compressor capacity or when there is an upset or accident, and the volume of gases is too great for the compressors to handle.
Emissions from Flares

Flares produce air pollutants through two primary mechanisms. The first mechanism is incomplete combustion. Like all combustion devices, flares do not combust all of the fuel directed to them. Combustion efficiency is the extent to which the oxidation reactions that occur in combustion are complete reactions converting the gases entering the flare into fully oxidized combustion products. Combustion efficiency may be stated in terms of the extent to which all gases entering the flare are combusted, typically called "overall combustion efficiency" or simply "combustion efficiency", or it may be stated as the efficiency of combustion for some constituent of the flare gas as, for example, "hydrocarbon destruction efficiency."

The second mechanism of pollutant generation is through the oxidation of flare gases to form other pollutants. As an example, the gases that are burned in flares typically contain sulfur in varying amounts. Combustion oxidizes these sulfur compounds to form sulfur dioxide, a pollutant. In addition, combustion also produces relatively minor amounts of nitrogen oxides through oxidation of the nitrogen in flare gas or atmospheric nitrogen in combustion air.

Unlike internal combustion devices like engines and turbines, flares combust fuel in the open air, and combustion products are not contained and emitted through a stack, a duct, or an exhaust pipe. As a result, emission measurement is difficult.

Studies can be conducted on small flares under a hood or in a wind tunnel where all combustion products can be captured. Any results for these small flares must be adjusted with scaling factors if they are to be applied to full-size flares. For full-size operating industrial flares, which may have a diameter of four feet or more and a stack height of 200 feet or more, all combustion products cannot be captured and measured. To study emissions from these flares, emissions can be sampled with downwind test probes attached to the stack, a tower, or a crane. Emissions can also be studied using remote sensing technologies like open-path Fourier transform infrared technology (FTIR) or differential absorption lidar (DIAL). In applying the results of any particular study to a specific flare or flare type, it is important to note any differences in flare design and construction. For example, some flares are simply open pipes, while others, like most refinery flares, have flare tips that are engineered to promote mixing. In addition, studies suggest that composition and BTU content of gas burned, gas flow rates, flare operating conditions, and environmental factors like wind speed may affect, to varying extents, the efficiency of flare combustion.

The question of flare combustion efficiency is one of the issues being explored by the Technical Committee of the BAAQMD Advisory Council. On April 1, 2003, District staff and representatives from Bay Area refineries made presentations to the Committee on various flare issues, including combustion efficiency. The Committee has indicated that it intends to examine the efficiency issue and may invite experts to appear before it.
Bay Area Flares and Existing Monitoring Equipment

There are 25 flares at the five Bay Area refineries. Two of these flares are not in operation. All of these flares in service have some existing monitoring equipment to monitor one or more of the following parameters: (1) hydrogen sulfide content of the fuel gas used for the pilot, (2) status of the pilot light, (3) flame appearance to insure a smokeless operation, (4) heating value of the gases, (5) compliance with limits on the amount of material processed at the flare, (6) quantity of fuel gas, and (7) total reduced sulfur content. Table 2 on the following page lists flares that would be subject to the proposed rule. For each flare, the table lists the existing monitoring equipment and the reason or reasons that the equipment is installed.

### Table 1: Existing Flare Monitoring

<table>
<thead>
<tr>
<th>Site &amp; Source #</th>
<th>Service</th>
<th>Parameter Monitored</th>
<th>Monitor Type</th>
<th>Basis¹</th>
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<tr>
<td><strong>Chevron</strong></td>
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<td></td>
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</tr>
<tr>
<td>6006</td>
<td>LSFO Low Level Flare</td>
<td>Pilot &amp; purge gas, btu &amp; HHV</td>
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<td>Disconnected</td>
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<td>LSFO High Level Flare</td>
<td>Pilot &amp; purge gas, btu &amp; HHV</td>
<td>Flow transmitter &amp; chart</td>
<td>PC</td>
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<td>Pilot gas, btu &amp; HHV</td>
<td>Rotameter</td>
<td>PC</td>
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<td>6013</td>
<td>North Isomax</td>
<td>Purge gas, btu &amp; HHV</td>
<td>Field meter</td>
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<td>D&amp;R Flare</td>
<td>Pilot &amp; purge gas, btu &amp; HHV</td>
<td>Flow transmitter &amp; chart</td>
<td>PC, NSPS</td>
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<td>Flow transmitter &amp; chart</td>
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<td>Flow transmitter &amp; chart</td>
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<td>Pilot &amp; purge, btu &amp; HHV</td>
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<td><strong>Shell</strong></td>
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<td>H₂S, flow</td>
<td>Venturi</td>
<td>PC, NSPS</td>
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<td>1772</td>
<td>HC Flare</td>
<td>H₂S, flow</td>
<td>Orifice</td>
<td>PC, NSPS</td>
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<td>4201</td>
<td>Delayed Coking Flare</td>
<td>Molecular wt., sulfur, btu/scf, fuel flow</td>
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</tr>
<tr>
<td><strong>ConocoPhillips</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>297</td>
<td>C-1 Flare</td>
<td>Flow</td>
<td>Ultrasonic, anemometer</td>
<td>PC, NSPS</td>
</tr>
<tr>
<td>398</td>
<td>C-602 Flare</td>
<td>Flow</td>
<td>Ultrasonic</td>
<td>PC, NSPS</td>
</tr>
<tr>
<td><strong>Tesoro</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>854</td>
<td>East Air Flare</td>
<td>Flow, sulfur</td>
<td>Ultrasonic</td>
<td>PC, NSPS</td>
</tr>
<tr>
<td>944</td>
<td>North Coker Flare</td>
<td>Flow, sulfur</td>
<td>Ultrasonic</td>
<td>PC, NSPS</td>
</tr>
<tr>
<td>945</td>
<td>South Coker Flare</td>
<td>Flow, sulfur</td>
<td>Ultrasonic</td>
<td>PC, NSPS</td>
</tr>
<tr>
<td>992</td>
<td>Emergency Flare</td>
<td>Flow, sulfur</td>
<td>Ultrasonic</td>
<td>PC, NSPS</td>
</tr>
<tr>
<td>1012</td>
<td>West Air Flare</td>
<td>Flow, sulfur</td>
<td>Ultrasonic</td>
<td>PC, NSPS</td>
</tr>
<tr>
<td>1013</td>
<td>Ammonia Flare</td>
<td>Flow</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Site &amp; Source #</td>
<td>Service</td>
<td>Parameter Monitored</td>
<td>Monitor Type</td>
<td>Basis¹</td>
</tr>
<tr>
<td>----------------</td>
<td>---------------</td>
<td>---------------------------</td>
<td>----------------------------------</td>
<td>--------</td>
</tr>
<tr>
<td>16</td>
<td>Acid Gas Flare</td>
<td>Purge flow</td>
<td>Orifice plate</td>
<td>PC</td>
</tr>
<tr>
<td>18</td>
<td>South Flare</td>
<td>Oil, flow, hydrocarbon</td>
<td>Venturi meter, anemometer</td>
<td>EB</td>
</tr>
<tr>
<td>19</td>
<td>North Flare</td>
<td>Oil, flow, hydrocarbon, H₂S</td>
<td>Venturi meter, anemometer</td>
<td>EB, NSPS</td>
</tr>
</tbody>
</table>

¹ PC - Permit Condition  
EB - Energy Balance  
NSPS - Federal New Source Performance Standards for flares used as a control device

As shown in the table, a variety of technologies are used to quantify the volume of gases combusted. Each technology has advantages and limitations. Some of these have been identified by EPA in their Compliance Assurance Monitoring (CAM) Technical Guidance Document and are summarized in Table 3 on the following pages.
<table>
<thead>
<tr>
<th>Type of Flow Meter</th>
<th>Type of Measurement</th>
<th>Liquid, Gas, or Both</th>
<th>Applicable Pipe Diameter</th>
<th>Applicable Flow Rate</th>
<th>Straight Pipe Requirements</th>
<th>Net Pressure Loss</th>
<th>Accuracy</th>
<th>Restrictions</th>
</tr>
</thead>
<tbody>
<tr>
<td>Venturi Tube</td>
<td>Volumetric</td>
<td>Both</td>
<td>5 to 120 cm (2 to 48 in.)</td>
<td>Limited to ~ 4:1 flow range</td>
<td>6 to 20 D up 2 to 40 D down</td>
<td>10 to 20% of ΔP depending on β</td>
<td>± 0.75% flow rate w/o calibration</td>
<td>Eliminate swirl and pulsations</td>
</tr>
<tr>
<td>Flow nozzle</td>
<td>Volumetric</td>
<td>Both</td>
<td>7.6 to 60 cm (3 to 24 in.)</td>
<td>Limited to ~ 4:1 flow range</td>
<td>6 to 20 D up 2 to 4 D down</td>
<td>30 to 8.5% of ΔP depending on β</td>
<td>± 1.0% flow rate w/o calibration</td>
<td>Eliminate swirl and pulsations</td>
</tr>
<tr>
<td>Orifice plate</td>
<td>Volumetric</td>
<td>Both</td>
<td>1.3 to 180 cm (1/2 to 72 in.)</td>
<td>Limited to ~ 4:1 flow range</td>
<td>6 to 20 D up 2 to 4 D down</td>
<td>Slightly more than flow nozzle</td>
<td>± 0.6% flow rate w/o calibration</td>
<td>Eliminate swirl and pulsations</td>
</tr>
<tr>
<td>Magnetic</td>
<td>Velocity Liquid</td>
<td>(not petroleum)</td>
<td>0.25 to 250 cm (0.1 to 96 in.)</td>
<td>0.0008 to 9,500 L/min (0.002 to 2,500 gal/min)</td>
<td>None</td>
<td>None</td>
<td>± 1% flow rate</td>
<td>Conductive liquid, not for gas</td>
</tr>
<tr>
<td>Nutating disk</td>
<td>Volumetric Liquid</td>
<td>Up to 10 cm (1/2 to 2 in.)</td>
<td>7.5 to 600 L/min (2 to 160 gal/min)</td>
<td>None</td>
<td>None</td>
<td>None</td>
<td>± 0.5% flow rate</td>
<td>Household water meter, low maximum flow rate</td>
</tr>
<tr>
<td>Oscillating piston</td>
<td>Volumetric Liquid</td>
<td>3.8 to 60 cm (1-1/2 to 24 in.)</td>
<td>30 to 68,000 L/min (8 to 18,000 gal/min)</td>
<td>None</td>
<td>None</td>
<td>None</td>
<td>± 0.5% flow rate</td>
<td>Household water meter, low maximum flow rate</td>
</tr>
<tr>
<td>Bellows gas</td>
<td>Volumetric Gas</td>
<td>3.8 to 60 cm (1-1/2 to 10 in.)</td>
<td>190,000 L/min (50,000 gal/min)</td>
<td>None</td>
<td>None</td>
<td>None</td>
<td>± 0.1% to 0.2% flow rate</td>
<td>Used for commercial and domestic gas service</td>
</tr>
<tr>
<td>Lobed impeller</td>
<td>Volumetric Both</td>
<td>0.64 to 60 cm (1/4 to 24 in.)</td>
<td>190,000 L/min (50,000 gal/min)</td>
<td>None</td>
<td>None</td>
<td>None</td>
<td>± 0.1% to 0.2% flow rate</td>
<td>Best used at high flow rates</td>
</tr>
<tr>
<td>Slide-vane rotary</td>
<td>Volumetric Liquid</td>
<td>Up to 40 cm (1 to 16 in.)</td>
<td>0.30 to 6.1 m/sec (1 to 30 ft/sec)</td>
<td>10 D up 5 D down</td>
<td>34 to 41 kPa @ 6.1 m/sec.</td>
<td>± 0.5% flow rate</td>
<td>Straightening vanes. Do not exceed maximum flow</td>
<td></td>
</tr>
<tr>
<td>Retracting-vane rotary</td>
<td>Volumetric Liquid</td>
<td>Up to 10 cm (1/4 to 4 in.)</td>
<td>0.30 to 6.1 m/sec (1 to 30 ft/sec)</td>
<td>10 D up 5 D down</td>
<td>34 to 41 kPa @ 6.1 m/sec.</td>
<td>± 1% flow rate (liquid) ± 2% flow rate (gas)</td>
<td>Straightening vanes</td>
<td></td>
</tr>
<tr>
<td>Helical Gear</td>
<td>Volumetric Liquid</td>
<td>3.8 to 25 cm (1-1/2 to 10 in.)</td>
<td>190,000 L/min (50,000 gal/min)</td>
<td>None</td>
<td>None</td>
<td>None</td>
<td>± 0.1% to 0.2% flow rate</td>
<td>High viscous liquids only</td>
</tr>
<tr>
<td>Turbine</td>
<td>Volumetric Both</td>
<td>0.64 to 60 cm (1/4 to 24 in.)</td>
<td>190,000 L/min (50,000 gal/min)</td>
<td>None</td>
<td>None</td>
<td>None</td>
<td>± 0.1% to 0.2% flow rate</td>
<td>High viscous liquids only</td>
</tr>
<tr>
<td>Vortex Shedding</td>
<td>Velocity Both</td>
<td>2.5 to 30 cm (1 to 12 in.)</td>
<td>0.30 to 6.1 m/sec (1 to 30 ft/sec)</td>
<td>10 D up 5 D down</td>
<td>34 to 41 kPa @ 6.1 m/sec.</td>
<td>± 0.1% to 0.2% flow rate</td>
<td>High viscous liquids only</td>
<td></td>
</tr>
<tr>
<td>Vortex Precession</td>
<td>Velocity Gas</td>
<td>2.5 to 20 cm (1 to 8 in.)</td>
<td>0.30 to 6.1 m/sec (1 to 20 ft/sec)</td>
<td>10 D up 5 D down</td>
<td>34 to 41 kPa @ 6.1 m/sec.</td>
<td>± 0.1% to 0.2% flow rate</td>
<td>High viscous liquids only</td>
<td></td>
</tr>
<tr>
<td>Fluidic oscillating</td>
<td>Velocity Liquid</td>
<td>2.5 to 10 cm (1 to 4 in.)</td>
<td>0.30 to 6.1 m/sec (20 ft/sec)</td>
<td>10 D up 5 D down</td>
<td>34 to 41 kPa @ 6.1 m/sec.</td>
<td>± 0.1% to 0.2% flow rate</td>
<td>High viscous liquids only</td>
<td></td>
</tr>
<tr>
<td>TOF ultrasonic</td>
<td>Velocity Both</td>
<td>&gt; 0.32 cm &gt; 1/8 in.)</td>
<td>Minimum 0.03 m/sec (0.1 ft/sec)</td>
<td>10 to 30 D up 5 to 10 D down</td>
<td>None</td>
<td>± 0.5% to 10% full scale</td>
<td>Need clean fluid</td>
<td></td>
</tr>
<tr>
<td>Type of Flow Meter</td>
<td>Type of Measurement</td>
<td>Liquid, Gas, or Both</td>
<td>Applicable Pipe Diameter</td>
<td>Applicable Flow Rate</td>
<td>Straight Pipe Requirements¹</td>
<td>Net Pressure Loss</td>
<td>Accuracy</td>
<td>Restrictions</td>
</tr>
<tr>
<td>--------------------</td>
<td>---------------------</td>
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<td>-----------------------------</td>
<td>------------------</td>
<td>----------</td>
<td>--------------</td>
</tr>
<tr>
<td>Doppler Ultrasonic</td>
<td>Velocity</td>
<td>Liquid</td>
<td>&gt; 0.32 cm (&gt; 1/8 in.)</td>
<td>Minimum 0.15 m/s (0.5 ft/sec); 0.38 L/min (0.1 gal/min)</td>
<td>Yes</td>
<td>None</td>
<td>As low as 1% flow rate</td>
<td>Fluid must have sufficient particles or bubbles</td>
</tr>
<tr>
<td>Thermo-anemometer</td>
<td>Velocity (mass)</td>
<td>Gas</td>
<td>&gt; 5 cm (&gt; 2 in.)</td>
<td>8 to 10 D up; 3 D down</td>
<td>Very low</td>
<td>± 2% flow rate</td>
<td>Critically positioned probes; Highly fluid composition dependent</td>
<td></td>
</tr>
<tr>
<td>Colorimetric</td>
<td>Velocity (mass)</td>
<td>Gas</td>
<td>&gt; 5 cm (&gt; 2 in.)</td>
<td>8 to 10 D up; 3 D down</td>
<td>Low</td>
<td>± 4% flow rate</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Coriolis mass</td>
<td>Mass flow</td>
<td>Both limited gas</td>
<td>0.16 to 15 cm (1/16 to 6 in.)</td>
<td>Definitive max. + min. flow rate</td>
<td>None</td>
<td>High</td>
<td>± 0.2% to 0.4% flow rate</td>
<td>Pressure drop across flow meter cannot exceed max. system pressure drop</td>
</tr>
<tr>
<td>Rotameter</td>
<td>Velocity</td>
<td>Both</td>
<td>1.3 to 10 cm (1/2 to 4 in.)</td>
<td>Up to 750 L/min (200 gal/min for liquid); unlimited for gas</td>
<td>None</td>
<td>Low</td>
<td>± 1 to 2% full scale</td>
<td>Must be mounted vertically</td>
</tr>
</tbody>
</table>
Flow Monitoring Technologies

The following discussions of flow monitoring technologies are taken from EPA's CAM Guidance. Discussion is limited to those technologies most common in the Bay Area refineries.

**Orifice Plates and Venturis**

Orifice plates can be used to measure fluid flow in pipes with diameters of approximately 1.3 to 180 cm (0.5 to 72 in.). Orifice plates operate on Bernoulli’s principle, which says that pressure decreases with increased flow velocity. An orifice plate consists of a square-edged or sharp-edged, thin opening in a metallic plate perpendicular to the flow. The opening is of a predetermined size and shape and is machined to tight tolerances. The flow velocity must increase through the orifice. The result is a higher pressure upstream of the plate and a lower pressure downstream. The pressure differential increases with flow velocity. The pressure readings for an orifice plate are obtained from a pair of pressure taps, one on either side of the plate:

![Figure 2. Orifice Plate](image)

Venturi meters operate on the same principle. The pressure differential for a venturi is obtained from two taps: one at the full pipe diameter and one at the throat of the venturi.

**Hot Wire Anemometer**

The hot wire anemometer (figure 3) works by measuring the current drawn through the hot wire as a result of the cooling effect of the air flow extracting heat from the wire. The instrument maintains the wire at a fixed temperature so that as it is cooled by the air flow the current increases to maintain the temperature of the wire. The core of the anemometer is an exposed hot wire either heated up by a constant current or maintained at a constant temperature (figure 4). In either case, the heat lost to fluid convection is a function of the fluid velocity.
Figure 3. Typical Hot-Wire Anemometer

By measuring the change in wire temperature under constant current or the current required to maintain a constant wire temperature, the heat lost can be obtained. The heat lost can then be converted into a fluid velocity in accordance with convective theory.

Figure 4. Anemometer Hot Wire
**Ultrasonic Flow Meters**

Two types of ultrasonic flow meters are available: time-of-flight (TOF) and Doppler. Doppler meters are suitable only for liquids and are not discussed here. In TOF ultrasonic flow meters, sound waves are introduced into the flowing fluid, one wave traveling with the flow and one wave traveling against the flow. The difference in transit time of the waves is proportional to the fluid flow rate, because the sound wave is accelerated when traveling with the flow and slowed when traveling against the flow. If the sound wave velocity of the fluid (speed of sound) is known, the transit distance is known, and time difference is known, then the fluid flow rate can be determined. Time-of-flight ultrasonic flow meters can be classified as one of the following: axial transmission, multi-beam (transverse or longitudinal) contra-propagating, cross beam, sing around, and reflected beam. Figure 5 depicts a TOF ultrasonic flow meter.

![Time-of-flight ultrasonic flow meter](image)

**Figure 5. Time of flight ultrasonic flow meter**

Ultrasonic flow meters are comprised of the following basic parts: the transducer, receiver, timer, and temperature sensor. Ultrasonic flow meters can be used to measure fluid flow in pipes with a diameter greater than 0.32 cm (0.125 in.) with a minimum flow rate of approximately 0.38 L/min (0.1 gal/min). Time-of-flight ultrasonic flow meters are applicable to liquids and gases flowing at velocities greater than 0.03 m/sec (0.1 ft/sec).
Gas Composition Monitoring

The type of composition monitoring currently in use at a refinery depends upon the applicable regulatory requirements, as shown in Table 2. Regulatory requirements are specified in the District imposed permit conditions or in Federal requirements. The most common requirement is that a flare be monitored for emissions of sulfur oxides to meet New Source Performance Standards for flares used as a control device. For some flares, the District has imposed conditions on flares for purposes of controlling odors or to meet offset requirements. Typically these conditions place limits on the quantity and composition of fuel gas that can be burned, impose design criteria for tip velocity, and specify analytical protocols. Some composition monitoring may be done to meet other needs of the facility. For example, some facilities analyze for composition to “energy balance” the consumption of fuel gas within individual process units. All of the composition monitoring being done at the Bay Area refineries at present is through sampling and subsequent lab analysis.

Composition can also be monitored by continuous analyzers. Several technologies are available: the flame ionization detector (FID), the non-dispersive infrared (NDIR) spectrophotometer, and gas chromatography (GC).

A flame ionization detector (FID) burns sampled gas in a hydrogen flame. Organic compounds produce positive ions, which are collected at an electrode above the flame. The generated current is then measured. The FID is useful for measuring concentrations of organic compounds and is very sensitive and accurate over many orders of magnitude. Because the FID responds to any molecule with a carbon-hydrogen bond, but not at all, or poorly to other compounds, it is not useful for measuring concentrations of hydrogen sulfide or sulfur dioxide.

A non-dispersive infrared (NDIR) spectrophotometer measures the amount of infrared radiation that is absorbed by a sample. Infrared radiation from a hot wire is directed through two parallel cells: a reference cell filled with nitrogen, and a cell through which the sample flows. The gas in the sample cell absorbs an amount of energy proportional to its concentration. This is converted into an electrical output by the detector. The NDIR is commonly used to measure carbon monoxide, carbon dioxide, methane, and total hydrocarbon concentrations.

A gas chromatograph, or GC, consists of a column, oven, and detector. The column separates the gas sample into its various components. GC columns are available in different sizes, and packing for the columns depends upon the composition of the gas stream to be analyzed. The oven provides a controlled temperature enclosure for the column. The detector has to be chosen based on the type of gases being analyzed. A thermal conductivity detector or a FID can be used as the detector on a gas chromatograph.

In the gas chromatograph, a sample goes to the column, separates into individual compounds and proceeds through the hydrogen flame ionization detector, generating a response called a chromatogram. The various chemical components contained within the sample travel through the column at different speeds, depending on their respective solubility in or adsorption on the packing material (liquid or solid). The height of the peak on the chromatogram is related to the
concentration and the time it takes to go through the column, which helps identify the component.

History of Monitoring

In 1984, Citizens for a Better Environment (CBE) petitioned the California Air Resources Board (CARB) to evaluate the feasibility of continuous emission monitors for refinery flares. CARB determined that no refinery in California accurately monitored flow rates to its flares. Several types of flow meters had been installed on refinery flares, but the instrumentation could only provide relative flow information because gas density varies and gas composition data is necessary to calculate flow accurately. CARB concluded that continuous monitoring of flow rates and composition and remote monitoring of flare plumes would require substantial development before it would be available. CARB determined that monitoring devices were available for limited applications to identify and record continuously the on/off status of flares. CARB also encouraged local air pollution control districts to adopt rules requiring refineries to install on/off status monitors and collect flare gas composition data so that a suggested control measure for the control of emissions from refinery flares could be developed.

In response to the CARB findings, the District conducted a flare monitoring study in 1988 and 1989 using the tools that were then available (BAAQMD 1990). Instantaneous flow information was obtained using pitot tubes. Composition was analyzed by taking grab samples at the same time that the flow measurement was made. All of the data simply gave the District a series of "snapshot" data. Conclusions had to be extrapolated from this limited data by assuming that it was representative of refinery operations, but there was no way to determine whether this was a valid assumption. Nevertheless, it remained the only flare flow and composition data set available for Bay Area refineries. The data collected was used as a basis for adjustments to the emission inventory used for the Bay Area 2001 Ozone Attainment Plan.

By the 1990's, ultrasonic flow meters were coming to be regarded as a reliable way to measure flare flows. Recognizing that the ultrasonic meters provided a reliable means of monitoring flare gas, the South Coast Air Quality Management District adopted its Rule 1118 requiring refinery flare monitoring. The rule was adopted in 1998, but there were numerous delays, and monitors were finally installed and operational by late 2000.
California Air District Regulations

The following table summarizes existing flare regulations within California.

**Table 3: California Flare Monitoring Rules**

<table>
<thead>
<tr>
<th>Regulation</th>
<th>Control/Performance Requirements</th>
<th>Monitoring Requirements</th>
<th>Minimization Plan</th>
<th>Emission Limitations</th>
</tr>
</thead>
<tbody>
<tr>
<td>SCAQMD Rule 1118</td>
<td>None</td>
<td>Gas flow, heating value and sulfur content</td>
<td>No</td>
<td>No</td>
</tr>
<tr>
<td>SJVAPCD Rule 4311</td>
<td>Open Air Flares &lt;5psig must meet 40 CF...</td>
<td>For flares used during an emergency, record of...</td>
<td>No</td>
<td>Ground level enclosed flares only</td>
</tr>
<tr>
<td>SBAPCD Rule 359</td>
<td>Heating value, exit velocity, automatic ignition system</td>
<td>Presence of a flame</td>
<td>Yes</td>
<td>Sulfur compounds may not exceed 15 grains per 100 cubic feet (239 ppmv) in the Southern Zone of Santa Barbara County or 50 grains per 100 cubic feet (796 ppmv) in the Northern Zone of Santa Barbara County; smokeless</td>
</tr>
</tbody>
</table>

In 1994, the Santa Barbara Air Pollution Control District (SBAPCD) adopted Rule 359, Flares and Thermal Oxidizers. This rule applies to flares and thermal oxidizers used in oil and gas production, petroleum refineries and related sources, natural gas supply and transportation sources, and in distribution petroleum/petroleum products. Rule 359 specifies sulfur content limits for flare gas, technology-based standards for flares and thermal oxidizers, emission limits for nitrogen oxides and reactive organic compounds, and operational limits. The rule also requires plans to minimize use of flares.

In 1998, the South Coast Air Quality Management District adopted Rule 1118 (Emissions from Refinery Flares), which requires refinery flare monitoring. Monitors were installed and operational by late 2000.

In 2002, the San Joaquin Valley Unified Air Pollution Control District (SJVUAPCD) adopted Rule 4311, Flares. This rule requires all open air flares to comply with federal limitations on sulfur in fuel gas. The federal requirement (40 CFR section 60.18) is found in New Source Performance Standards and, in the absence of the SJVUAPCD rule, would apply only to new flares. The rule does not impose extensive monitoring requirements like those in the proposed District rule or in SCAQMD Rule 1118.
PROPOSED RULE

Proposed Regulation 12, Rule 11 would require refiners to:

- Continuously monitor vent gas flow for each flare;
- Monitor vent gas composition either by (1) taking samples manually or with an auto sampler, or by (2) using continuous analyzers;
- Submit monthly reports that include vent gas flow and composition, pilot and purge gas flow, estimates of hydrocarbon and sulfur emissions, descriptions of all flaring of more than 1 million standard cubic feet of vent gas (duration, time, cause, measures to reduce or eliminate), and monitor downtime;
- Monitor flare operation by video camera and record and retain recordings of flare images.

These requirements would be imposed in steps that are based upon the District's determination about the length of time required to install the necessary equipment:

- Effective in 90 days, each refinery would be required to begin daily sampling for composition when there is flaring activity. (Some refiners already have this capability and are reporting this data to the District pursuant to an agreement entered into pursuant to the flare further study effort described in the introduction; others will have to install necessary sampling ports.)

- Effective in 180 days, each refinery will have to have continuous flow monitors in place. This effective data is based upon the expectation that the manufacturer of ultrasonic flow monitors will be able to supply, and the refiners will be able to install, these monitors within this time.

- Effective in 270 days, each refinery will be required to have in place the equipment necessary to monitor composition at more frequent intervals or continuously. If sampling is chosen, the refineries will have to determine how to take more frequent samples, either through installation of auto-samplers or additional staffing, and how to process these samples, either in their own labs or through outside labs. If continuous analyzers are chosen, the refineries will have to design and install sample conditioning systems and analyzers, or arrange to have this work done by outside vendors.

The following sections of the staff report discuss the provisions of the proposed rule in the order in which they appear in the rule. In this discussion, the rule prepared and made available with the public notice for the May 21st hearing is called the “proposed rule.” This is in keeping with standard terminology used by ARB, air districts, and the Health and Safety Code (§§40725, 40726). The revised version of the rule now proposed for adoption is called the “revised rule.” Earlier drafts of the rule are called “earlier drafts.”
Exemptions

The exemptions are intended to make it clear that the rule applies to flares and not other types of abatement devices used to control small sources and operations such as storage tanks or loading racks. These sources are subject to other BAAQMD rules and permit conditions. In particular, the exemptions make it clear that the rule is not intended to apply to thermal oxidizers, which differ from flares in numerous respects but most importantly in having emissions that can be directly measured and verified by source tests. For a discussion of this issue, see the discussion of the definition section of the rule below.

Section 12-11-110 Exemption, Organic Liquid Storage and Distribution

This exemption would exempt flares or thermal oxidizers controlling emissions exclusively from storage tanks or loading racks. The exemption would apply to six sources in the District. The first is a backup safety flare that serves a vapor recovery system for a propane tank at the Tesoro refinery. This flare is designed to control emissions from the propane tank if the tank’s vapor recovery system fails or is taken out of service for maintenance. The second is also a backup safety flare that serves a vapor recovery system for a butane tank at the Valero refinery. This flare serves the same purpose as the flare at Tesoro. The other four sources are located at the Shell refinery. Three of the flares are backup safety flares for three vapor recovery systems that serve fixed roof storage tanks. The other Shell flare serves a liquefied petroleum gas (LPG) railcar loading operation at the Shell refinery. Railcars are unloaded using natural gas to push the LPG (propane and butane) out of the railcar. When railcars arrive at the refinery for loading, propane and butane displace the natural gas to the flare. So this flare combusts natural gas and small amounts of LPG that vaporizes during the loading. For 2002, Shell loaded 971 tank cars. Total annual non-methane hydrocarbon emissions from the flare were approximately 1000 pounds. All of the flares exempted by this provision, with the exception of Shell’s railcar loading flare, are backup safety flares and are not primary control devices. At 3 pounds per day, emissions from Shell’s railcar loading flare are not significant.

Section 12-11-111 Exemption, Marine Vessel Loading Terminals

Marine vessel loading terminals are located at all five Bay Area petroleum refineries. All terminals are subject to Regulation 8, Rule 44, which requires that emissions from the loading of specified cargos by reduced by 95% or to 2 pounds per thousand barrels of cargo loaded. Thermal oxidizers are used at the Chevron, ConocoPhillips, and Shell refineries to meet the rule’s control requirements. No terminal uses a flare for control. The thermal oxidizers at the three marine terminals have high efficiencies that are mandated by the rule and by permit conditions and can be directly verified by source tests. Because these devices are, by definition, thermal oxidizers, they are not subject to the rule. This exemption is therefore included merely to clarify that this is the case.

Section 12-11-112 Exemption, Wastewater Treatment Systems

The Valero and Tesoro refineries each use a thermal oxidizer to control components of the refinery wastewater treatment system. As discussed above, properly operated thermal oxidizers
have high control efficiencies that can be verified by source tests. Like all thermal oxidizers, these thermal oxidizers are, by definition, not subject to the rule, and the exemption is included to make this clear.

**Section 12-11-113 Exemption, Pumps**

Pumps are subject to the District's equipment leak rule, Regulation 8, Rule 18. The rule imposes the most stringent equipment leak limits in California, and one way of complying is by installing containment around a pump seal and directing emissions to an abatement device. Both the Chevron and Tesoro refineries use thermal oxidizers to control emissions from some pump seals. These thermal oxidizers are, by definition, exempt from the rule, and the exemption is intended to make this clear. If fugitive emissions from pumps are directed to the refinery's general blowdown and relief system, additional language makes it clear that the exemption would not apply to exempt a flare that might combust these emissions.

**Section 12-11-114 Limited Exemption, Total Hydrocarbon and Methane Composition Monitoring and Reporting**

This section does not appear in the proposed rule. Earlier drafts of the rule included a broader exemption from hydrocarbon reporting for flares that exclusively serve sulfur plants and ammonia plants or exclusively burn flexicoker gas. This broad exemption was dropped from the proposed rule.

Staff are now recommending a more limited exemption for flares that exclusively burn flexicoker gas with or without supplemental natural gas. Coking is a final refining stage that separates light products from the heavy coke byproducts of refining. The process converts feed with a very high carbon/hydrogen ratio into distillate products. Flexicoking is a continuous coking process that minimizes coke production and maximizes the production of useful products. It uses a gasifier in which steam and air are combined with the coke to produce gas. After hydrogen sulfide is removed from the gas, it is used as a fuel within the refinery. The process leaves very little coke.

Flexicoker gas has very consistent composition. Gas from the flexicoker at the Shell refinery is primarily nitrogen, carbon monoxide, hydrogen, and carbon dioxide. It typically has a methane content of less than 2%, a non-methane hydrocarbon content of much less than 1%, and very low sulfur content. A flare is used to burn flexicoker gas that cannot be used by the refinery. Under this exemption, Shell's flexicoker flare would be exempt from hydrocarbon monitoring requirements provided it meets the conditions in the exemption that limit methane content to less than 2% and non-methane hydrocarbon content to less than 1%. Monitoring for flow and sulfur composition would still be required.

**Definitions**

As with all District rules, the proposed flare monitoring rule defines key terms used in the rule. There are two things to note about the definitions. First, the terms "flare" and "thermal oxidizer"
are defined (Sections 12-11-201 and 209) to make it clear that the rule applies to the flares that are listed in this staff report and not to thermal oxidizers and other abatement devices. The distinction drawn between flares and thermal oxidizers is that the latter term describes an enclosed combustion device that exhausts all combustion products through a vent, duct, or stack so that emissions can be measured directly. The intent of this rule is to require monitoring of open-flame devices—flares—from which emissions cannot be measured in the conventional manner. For a flare, there is no stack or duct in which probes can be located and emissions measured. The rule therefore requires the monitoring of gases directed to flares. The rule is not intended to impose these same requirements on thermal oxidizers, from which emissions can be measured directly, and the definitions are intended to draw this distinction. Thermal oxidizers typically have VOC destruction efficiencies that range from 98 to 99.99% and above.

A second important aspect of the definitions is that the term "vent gas" is defined (Section 12-11-210) to include all gas directed to a flare, excluding steam or air used to aid combustion and excluding pilot and continuous purge gas. This definition is then used in the definition of "flaring" (Section 12-11-203). The result is that "flaring" is any time the flare has a flame other than the pilot flame. The term is used in the interim sampling provisions in Section 12-11-502.2 to ensure that samples are taken while active flaring is occurring.

Administrative Requirements

The Administrative Requirements set forth reporting requirements.

Section 12-11-401 Flare Data Reporting Requirements

In the proposed rule, this section requires a monthly report that must include the following:

- Upon rule adoption, total flow for each day and for the month. The Bay Area refineries currently have various means of determining flow and are reporting this data to the District pursuant to an agreement developed for flare further study measure FS-8. The rule will require continued reporting of this data. After the flow monitors required by Section 12-11-501 are installed, the report would also have to include flow for each hour of the month (ultrasonic flow monitors are capable of providing much greater flow detail than the means currently employed by most of the refineries).

- Methane, total hydrocarbon and sulfur content for every vent gas sample, and if continuous analyzers are used, for every hour of the month.

- If the flow monitor measures molecular weight (as ultrasonic monitors do), the average molecular weight of vent gas for each hour of the month.

- Type and quantity of pilot gas and purge gas used for each day and for the month. Where these flows are constant because of flare design, the parameters that dictate flow and the resultant flow are sufficient.
• For any 24-hour period during which more than 1 million standard cubic feet of vent gas are flared, a description of the flaring, including time, duration, cause, the source of the vent gas, and any measures taken to reduce or eliminate flaring.

• Flare monitoring downtime.

• The archive of video images required by Section 12-11-507.

The revised rule adds a requirement for calculated emissions that was included in earlier drafts but dropped from the proposed rule. At the request of WSPA and the Unions at the May 8th flare workgroup meeting, the revised rule re-incorporates a requirement for emission calculations. The Unions suggested using the efficiencies specified in the Texas rule (98% for most flares, 93% for low-BTU gases). While WSPA has argued for higher efficiency, the revised rule includes the Unions’ suggestion.

The reasoning behind specifying an efficiency figure, as articulated by the Unions and WSPA, seems to be that it is better to provide the public with some estimate of total emissions, even if the estimate employs some assumptions that are open to debate. District staff was persuaded by this reasoning, and so has incorporated assumed efficiencies in the proposed rule. However, it is important to note that these efficiencies are set for the narrow purpose of emissions estimates to be made in reports submitted by refineries pursuant to the rule. The revised rule does not restrict the District or anyone else from using a different efficiency figure in any other context. If the District does use a different efficiency figure, it will of course explain it’s reasoning for doing so. If more reliable information regarding flare efficiency becomes available, the District will consider revising the rule to reflect that information.

The revised rule also adds language to this section to require the submission of additional composition data that is not required by the section but is available from sampling analyzers or continuous analyzers.

On May 21, 2003 following the initial hearing on the rule, the District convened a meeting of the flare workgroup to discuss issues raised at the hearing. The meeting was attended by representatives for WSPA, the individual refineries, refinery trade unions, and CBE. In response to concerns raised by the unions and CBE, a minor change to the revised rule is proposed in Section 12-11-401.9. The revised rule incorporated the concept of specifying an efficiency of 98% except for low-BTU flexicoker gas, for which 93% was the default value. Staff are now proposing a change that requires the use of 93% for any vent gas with a lower heating value less than 300 British Thermal Units/Standard Cubic Feet (BTU/SCF). This is a minor change because data gathered during the flare study shows that most flare gas, with the exception of flexicoker gas, exceeds this BTU threshold.

Section 12-11-402 Flow Verification Report

This section requires a semi-annual report on alternative means of determining flow to serve as a check on the data being provided by the flow monitors. Ultrasonic flow monitors provide the most accurate and reliable means available to determine flare header flow. No currently
available alternative method can provide similar precision or accuracy. If the ultrasonic monitor has been installed and calibrated properly and the data logger has been programmed properly, the data should be reliable. In one case during the flare study recently conducted by the District, a refinery submitted data from an ultrasonic monitor and mistakenly assumed that the ultrasonic monitor range setting was 10 times the actual set range (for example, a value was assumed to be 5 million when it was actually 500,000). The required semi-annual report will provide a means of detecting such errors through a comparison of other data to the reported data. There are several alternative ways of determining flow that can be used as a "reality check" on the monitor. These alternatives are listed in Section 12-11-602 (see the discussion of that section for an explanation of each alternative). If a semi-annual report suggests that there may be a problem with a monitor, the District will be able to investigate further to determine whether the monitor still meets the requirements of Section 12-11-501 (requiring the monitor to accurately measure flow rate).

No other flare monitoring rule includes a flow verification requirement. This is true of both the South Coast AQMD petroleum refinery flare and the Texas chemical plant flare rule. This is primarily because it is difficult to know whether differences between ultrasonic flow meter measurements and measurements through alternate means should be attributed to inaccuracy in the meter or in the alternate method. (For more information on this issue, see the discussion of Section 12-11-501.)

For these reasons, it is difficult to specify how close the meter measurement must be to the expected measurement as derived from the flow verification. In the revised rule (Section 12-11-501), staff is including language that would specify that the difference be no greater than ±20%.

Monitoring and Records

The Monitoring and Records requirements are central to the rule and impose the various monitoring and recordkeeping requirements.

Section 12-11-501 Vent Gas Flow Monitoring

This section requires continuous monitoring of vent gas flow. The proposed rule specifies that the device used to do this monitoring (1) must be capable of detecting a minimum flow velocity of 0.1 feet per second, (2) must continuously measure the range of flow rates corresponding to flow velocities from 0.5 to 275 feet per second, and (3) must be installed on the flare header in a location that ensures that the device measures all flow. Three additional requirements are recommended by staff and are included in the revised rule. These additional requirements would specify that the device (1) must have a manufacturer's specified accuracy of ±5% over the range from 1 to 275 feet per second, (2) must be maintained to be accurate to within ±20% as demonstrated by the flow verification report specified in Section 12-11-402 (effective 12 months after installation), and (3) must be accessible to the APCO to verify proper installation and operation.
Section 12-11-501.1 requires the use of a device having a limit of detection of 0.1 feet per second. The “limit of detection” of an instrument is the lowest value of a parameter being measured that an instrument can reliably distinguish from zero. The limit of detection in the rule comes from ultrasonic flow meter product literature, and the value is from laboratory testing. Product literature from two manufacturers of ultrasonic flow meters (Panametrics and Roxar) both specify minimum detectible velocities in this range.

The primary criterion for any device installed pursuant to this section is that it be able to measure flow velocities over the range from 0.5 to 275 feet per second (Section 12-11-501.2). This range is taken from product literature for ultrasonic flow meters and is the general range over which the manufacturers claim the meters to be accurate. The revised rule now includes the manufacturer’s specified accuracy based on laboratory testing (Section 12-11-501.3 in the revised rule).

“Accuracy” is used in EPA and District regulations and in metrology, the science of measurement, to mean closeness to the truth. Although the ultimate true value of any parameter being measured cannot be known, accuracy is treated as the difference between a value measured by an instrument and an accepted true value or standard. These accepted values or standards are established by the National Institute of Science and Technology (NIST) or other nationally recognized measurement standards bodies. NIST was formerly the National Bureau of Standards and is responsible for developing, maintaining, and retaining custody of U.S. national standards of measurement. For example, a carton of milk is filled based on a NIST standard for measuring volume. Time throughout the U.S. is based on the official NIST time as maintained by NIST’s atomic clock in Boulder, Colorado.

For fluid flow, there are no standard measurement artifacts like those for length or volume. Instead, NIST has established flow measurement standards based on devices that deliver a measured volume of fluid over a measured time interval, with these measurements referenced to established NIST standards for volume and time. NIST provides calibration services for gas flow meters, thus allowing testing laboratories to calibrate master flow instruments that can be used to verify the accuracy of meters for field use. Accuracy for ultrasonic flow meters therefore generally refers to the closeness to the NIST-established “truth” under laboratory conditions. Although many laboratories can test liquid flow meters, there only a few testing laboratories in the United States that can test ultrasonic gas flow meters against standards traceable to the NIST standards.

Though ultrasonic flow monitors can be calibrated at a flow laboratory prior to installation and can be determined to measure known flows accurately, unless the calibration facility can replicate the pipe size and likely conditions under which the meter will operate in a particular flare header, one simply can't say with certainty what the accuracy of field measurements will be. However, because these meters are extremely accurate under laboratory conditions, it is reasonable to assume that properly installed meters are accurate in the field. For any method used to check meter accuracy in the field, it is difficult to know whether differences between the meter measurement and the measurement derived using some alternate method should be attributed to inaccuracy in the meter or in the alternate method.
Staff recommend, and the revised rule includes in Section 12-11-501.6, an accuracy specification based on the flow verification required by Section 12-11-402. The revised rule states that effective 12 months after installation of the ultrasonic meters, the flow verification shall demonstrate a meter accuracy of ±20%. This will allow a year of experience with the meters and with various flow verification methods. District staff expect that through this experience it will become clear whether the accuracy requirement can be met. District staff is proposing to report back to the Board 18 months after rule adoption. If it appears that the specification should be changed, staff can recommend appropriate changes at that time.

Section 12-11-501.4 requires that the meter be installed at a location that ensures that the device measures all flow. An early draft of the rule specified that the meter must be installed at a location after the knockout pot, after all locations at which supplementary fuel is introduced, and after the water seal. This more prescriptive language was derived from a recently adopted Texas rule that applies to flares that combust certain highly-reactive VOCs. (Because refinery flare gas does not typically contain significant amounts of these highly-reactive VOCs, the Texas rule would not apply to most refinery flares and is instead intended to apply to chemical plants.)

District staff determined that using the prescriptive approach of the Texas flare rule in this context would have required the installation of meters within the radiation zone for some Bay Area flares. Less prescriptive language is proposed to allow discretion to locate a meter where it would still measure all significant flows while avoiding damage to the meter.

Section 12-11-501.5 specifies, effective 180 days after adoption of the rule, that the APCO is to have access to the flow monitoring system to verify proper installation and operation.

**Section 12-11-502 Vent Gas Composition Monitoring**

This section requires composition monitoring of vent gas. At present, some of the Bay Area refineries are taking daily samples of vent gas for lab analysis. Within 90 days after rule adoption and until more stringent requirements in the section take effect, all Bay Area refineries are required to take and analyze a grab sample for each day on which there is flaring activity (Section 12-11-502.2). These samples are required to be taken within 30 minutes after flaring begins.

Effective nine months after rule adoption, more stringent composition monitoring requirements take effect. Refiners will have two primary options: (1) sampling and subsequent lab analysis, or (2) the use of continuous analyzers. There are then alternatives with each of the primary options. The various options are discussed below.

**Sampling**

Sampling is proposed as an option because the technology is proven, is robust, and is already in widespread use. Sampling can be more economical because sampling equipment will not require sample conditioning trains as complex as those required for continuous analyzers. However, sample processing in a lab can be labor and time intensive, and, with a short sampling interval, can become as expensive as other options. Both manual sampling and auto-sampling are proven
in practice. A number of refineries in Southern California are using auto-samplers to take vent gas samples as required by the South Coast AQMD flare monitoring rule. With manual sampling, great care must be taken to ensure the safety of refinery workers involved in sampling. In some cases, the available sampling locations may have potential to expose workers to dangerous high temperatures if the vent gas flow rate is high.

The proposed rule allows only integrated sampling, which relies upon automated sampling equipment. Integrated sampling produces a composite sample out of individual aliquots taken over time. An aliquot is a fractional part of the sample that is an exact divisor of the whole sample. For example, ten aliquots of 100 milliliters each could compose a 1 liter sample. Because the aliquots are taken over time, the sample reflects variation in composition that may occur over time. Integrated sampling was included as the only sampling option in the proposed rule because of its potential to reflect composition variation with time.

District staff now recommend that two alternative sampling options be available: manual sampling and integrated sampling. The revised rule reflects this recommendation. The reason for including a manual sampling option is that a number of flares in the District are very rarely used: some less than once in a year and others less than once in several years. For these flares, a requirement to use integrated sampling or continuous analyzers would dictate the installation and maintenance of expensive and sensitive equipment that would rarely be used. This equipment would require regular attention to ensure that it remains in a state of readiness. As a result, Section 12-11-502.3.1 sets forth a manual sampling option.

This manual sampling option is probably not practical for flares that are used with some regularity. The need to continually take samples would be burdensome, and would likely result in missed samples. The likely outcome of the inclusion of this option is that its use will be restricted to these low usage flares.

On May 21, 2003 following the initial hearing on the rule, the District convened a meeting of the flare workgroup to discuss issues raised at the hearing. The meeting was attended by representatives for WSPA, the individual refineries, refinery trade unions, and CBE. In response to concerns raised by WSPA and individual refineries, a minor change to the revised rule is proposed in Section 12-11-502.3.1.a. The revised rule allowed up to one hour to take the first sample for a flare serving a sulfur plant. The reason for the proposal was that taking a sample at such a flare could expose workers to extremely dangerous concentrations of hydrogen sulfide. Safety procedures would require the use of extensive safety equipment including self-contained breathing gear. Because preparation for taking such a sample would require a significant amount of time, the allowance was one hour rather than 15 minutes to take the first sample. At the flare workgroup meeting, the refiners pointed out that the same risks applied at ammonia plant flares. Staff are now proposing a minor change that would extend the same allowance to these flares and also give refiners an additional option of submitting worst-case composition data in lieu of undertaking sampling that could be extremely hazardous under some circumstances. The data would have to be verified by the APCO as properly representing worst-case composition.

As noted, the only sampling option included in the proposed rule was integrated sampling. District staff are recommending retention of this option with modifications to the sampling
trigger and additional language to ensure that sample containers are not left in service for more than a day.

**Sampling Trigger**

Staff recommend adoption of the South AQMD trigger for sampling. The revised rule states that if the flow rate in any consecutive 15-minute period continuously exceeds 330 standard cubic feet per minute, sampling must begin within 15 minutes. Sampling must continue until flow rate in any consecutive 15-minute period is continuously 330 standard cubic feet per minute or less. The proposed rule set the sample trigger for integrated sampling at 6,000 standard cubic feet in a 15-minute period. An earlier version of the rule proposed 50,000 standard cubic feet in one hour as the trigger for sampling.

All efforts to set the sampling trigger have been based on setting the trigger at the lowest flow velocity at which (1) the flow meter is accurate and (2) the measured flow would represent real flow to the flare. The earlier draft’s proposed trigger of 50,000 standard cubic feet in an hour was based on a flow velocity of 1 foot per second. In response to comments from community and labor groups, the triggers in both the proposed rule and the revised rule are based on a flow velocity of approximately 0.5 foot per second. The recommended trigger included in the revised rule is identical to the trigger in the South Coast AQMD flare monitoring rule.

The flow velocity for a given volumetric flow rate depends upon the size of the flare header. The table below lists volumetric flow rates for flow velocities of 1 foot per second and 0.5 foot per second in various sized flare headers.

**Table 4: Flow as a Function of Header Size and Velocity**

<table>
<thead>
<tr>
<th>Volumetric Flow Rate for Given Flow Velocities (ft³/hr)</th>
<th>24&quot;</th>
<th>30&quot;</th>
<th>42&quot;</th>
<th>48&quot;</th>
</tr>
</thead>
<tbody>
<tr>
<td>Flow Velocity (feet/sec.)</td>
<td>1.0</td>
<td>0.5</td>
<td>1.0</td>
<td>0.5</td>
</tr>
<tr>
<td></td>
<td>11,310</td>
<td>17,671</td>
<td>34,636</td>
<td>45,239</td>
</tr>
<tr>
<td></td>
<td>5655</td>
<td>8836</td>
<td>17,318</td>
<td>22,619</td>
</tr>
</tbody>
</table>

Because most of the refineries have one or more large (42 inch or 48 inch) flare headers, using flow above 50,000 standard cubic feet per hour as a trigger ensures that sampling is triggered only when flow velocity is more than 1 foot per second in flare headers. Using an hourly trigger of 20,000 standard feet per hour (or about 330 standard cubic feet per minute over 15 minutes) ensures that sampling is triggered only when flow velocity is approximately 0.5 foot per second.

Several reasons support setting the trigger for sampling at a flow velocity of approximately 0.5 feet per second or higher. First, ultrasonic flow meters are not considered by manufacturers and users to be as accurate at flow velocities below about 0.5 feet per second.

Second, large flare headers are subject to various effects that produce low velocity currents within the header that do not represent flow to the flare. Such effects include the differential heating of a header by the sun producing stratification and circulation of gases and the suction of
a compressor producing a surging effect on gas in the header. As a result, eddies can form and move within a header. As a result of these effects, gas can move past the sensors of the flow meter when no flaring is occurring. With a lower trigger, flow may be indicated where none exists (i.e., a false positive flow). Under such circumstances, samples would not represent actual vent gas but would instead represent still gas in the header and could bias results.

A third reason for choosing the recommended trigger level is that an analysis of data collected during the District's flare study shows that use of this level would capture most of the flaring events of significance. Even if some events are missed, the larger events caught by this trigger will yield an extensive collection of data that will vastly expand understanding of the composition of flare gas.

A fourth reason for choosing this trigger level is that the data loggers used to record flare flow can be easily programmed to compare gas volume flared for the current minute against the trigger and to recognize when there are 15 consecutive minutes of flow about the trigger level. This will provide a clear signal for triggering sampling and can be easily enforced.

A fifth reason for choosing the proposed trigger level is that alternative forms appear to be more problematic. One alternative trigger that would still rely on the ultrasonic flow meter might be a sustained flow velocity exceeding 1 foot per second over some period of time. The disadvantage is that the sampling trigger would then vary with header size, which seems inequitable. In a small header the flow volume would be relatively inconsequential while significant in a large header. Use of a trigger other than the ultrasonic flow meter was also considered. A visual trigger tied to video monitor images could be used but would be subjective and difficult to enforce. Use of a trigger based upon flare header pressures that exceed the flare water seal pressure for some period of time would require instrumentation of water seals, and there is little District or industry experience with this data and its correlation to flow.

**Continuous Analyzers**

The other option for determining vent gas composition is the use of continuous analyzers pursuant to Sections 12-11-502.3.2 and 502.3.3. Several technologies are available: (1) flame ionization detectors (FID), (2) non dispersive infrared (NDIR), and (3) gas chromatography. These technologies were described above under "Background."

Continuous analyzers are widely used to monitor gas composition in the chemical and petroleum industry. However, District staff have been unable to identify any refinery in California or Texas using a continuous analyzer to monitor flare vent gas composition. One of the difficulties of monitoring vent gas is that it can include water, oil, rust and other particles, a very wide range of organic compounds, and high sulfur levels. In general, continuous analyzers need to be carefully tailored to a relatively predictable gas stream. In addition, samples need to be carefully conditioned to remove water and particles. Use of continuous analyzers will therefore require design and installation of a sample conditioning system. There is no off-the-shelf system available for this service. While District staff believe that such a system can be made to work, the technological challenges are not fully known. Until these systems are designed and installed, the maintenance needs for such a system are unknown. Because of the nature of the vent gas
stream, it seems likely that these sample conditioning systems will require more maintenance than those in more conventional service.

**Rationale for Options**

The rule allows the two primary options, sampling and continuous analyzers, because each has advantages and disadvantages that may dictate one over the other for the specific flare in question. Sampling is a proven approach. Though continuous data is desirable, continuous analyzers have not yet been proven as a technology to monitor flare vent gas, which is not as "clean" as most gas streams for which these analyzers are used. Use of continuous analyzers will require sample conditioning equipment that may be more difficult to design than those required for sampling and may require considerable maintenance. The rule represents a compromise, allowing a method that is known to work (sampling) while encouraging a method that the District would like to see proven in practice (continuous analyzers). This ensures that the rule will work and avoids the risk of rule failure that would come from mandating only continuous analyzers and the missed opportunity that might come from mandating only sampling. District staff expects that the result may be the use of continuous analyzers on some flares and sampling on others. District staff expects that either approach will provide sufficient data to support the accurate characterization of flare gas composition.

**General Requirements**

Section 12-11-502.1 specifies requirements that apply to all composition monitoring. Vent gas monitored for composition must be taken from a location that is representative of vent gas composition. Where flares share a common header, a sample from the header is sufficient for all flares served by the header. The composition monitoring system must provide a means for the District to take samples to verify the composition analyses required by the rule.

**Section 12-11-503 Pilot Monitoring**

This section requires each pilot to have a properly functioning ignition system. Most flares have pilot lights and most have an electric arc backup in case the pilot is lost.

**Section 12-11-504 Pilot and Purge Gas Monitoring**

This section requires monitoring of pilot and purge gas either by a flow measuring device or by the monitoring of other parameters. Most of the refineries rely on water seals rather than purge gas, and volumetric flow of pilot gas is constant and dictated by pilot design. Under these circumstances, the monthly report can simply state the parameters that dictate flow and repeat the flow data each month (see discussion of Section 12-11-401).

**Section 12-11-505 Recordkeeping Requirements**

Pursuant to this section, monitoring records, except for video monitoring, must be kept for 5 years. The section repeats existing requirements contained in federal law for Title V facilities.
Section 12-11-506 General Monitoring Requirements

General monitoring requirements that apply to all monitors are included in this section. The section limits hours of monitor inoperation and requires reporting when monitors go out of service. Monitors are allowed 15 consecutive days of inoperation, with proof of expeditious repair required after the 15 days and with a limit of 30 days total in one year. During periods when monitors are out of service, flows must be calculated and composition must be determined by sampling. Monitors are required to be maintained and calibrated in accordance with manufacturer's requirements. Finally, the section specifies that the electronic data loggers used to record data must be capable of one-minute averages and must record flow data as one-minute averages. Continuous composition analyzers do not produce one-minute averages, as the cycle for such an analyzer may take 15 minutes or more.

The revised rule includes amendments to the monitor downtime provisions that are intended to encourage the use of integrated sampling and continuous analyzers. Though these approaches have not yet been used on flare headers, several Bay Area refineries are interested in trying one or more of these options, but are concerned that the downtime provisions are too stringent for new equipment with which they have no experience. The changes to this section allow a 6 month grace period for integrated sampling, continuous analyzers, and gas chromatography during which the downtime limits will not apply. This will give the refineries time to work out any problems and acquire experience with the new equipment.

In response to comments from the Air Resources Board received just before the May 21, 2003 hearing on the revised rule, District staff are proposing two minor changes to Section 12-11-506.1 of the revised rule. The first change would delete an allowance of monitoring downtime for purely manual sampling, for which a downtime allowance is inappropriate (see response #127 in Comments and Responses). The second change would correct a typographical error in the same section (see response #128).

Section 12-11-507 Video Monitoring

This section requires the installation within 90 days of recording equipment for flares currently equipped with video monitoring equipment. Effective in 6 months, video monitors and recording equipment must be installed on each flare that currently lacks video monitoring equipment and that has a significant release (1 million standard cubic feet of vent gas in 24-hour period) as measured by the ultrasonic flow monitors.

The video monitoring requirements are intended to provide a backup to the extensive data that will be available after the rule's other monitoring requirements go into effect. Recorded video will serve as a broad scale verification on the operation of flow monitors. For instance, if recorded video shows a significant flaring event that is not indicated in monitoring data, this would be indicative of monitor equipment failure. In this way, recorded video data will provide an additional benefit in linking actual flaring events with emissions data and will thereby further the District compliance and enforcement capabilities. Though recorded video is not nearly as useful as other forms of monitoring for determining the quantity or character of flare emissions, its low cost and utility as a gross verification method justifies its inclusion in the rule.
Community members originally asked for video monitoring so that the District would have the means to verify complaints about flaring. In the past, flaring complaints occasionally came to the District on weekends or at other times when a District inspector was unable to verify the complaint. In the past, however, inspectors did not have the flow and composition data that will now routinely be available. It is possible, but uncertain, that video data will assist the District in responding more effectively to community complaints. The District believes this possibility, combined with the usefulness of video data as a broad scale verification on monitor function, justifies imposition of the requirement. With the proposed rule, video data will be redundant, but the recordings will provide an additional check on flaring.

At the District's August 2002 conceptual workshop for the proposed rule, community members asked for video monitoring with retention of images for a period sufficient to allow verification. The District's original proposal was to require recording of images and retention of the images for 72 hours. At community meetings, many participants requested retention for a greater length of time. The proposed rule therefore requires retention and submission of the images recorded during a particular month with the monthly report required by Section 12-11-401. This requirement ensures that images will be available to answer questions raised by neighbors or by District staff after reviewing the report.

This section specifies certain minimum requirements for the images and recording. The flare image must be of sufficient size, contrast, and resolution to be readily apparent in the overall image or frame and it must include an embedded date and time stamp.

The image of the flare must be recorded at a frame rate of no less than 1 frame per minute. This frame rate was selected to ensure that the resulting size of the electronic file was no bigger than could be recorded on one DVD per flare per month. In arriving at this frame rate, the District assumed that the individual image file for each image of the flare would be 40 kilobytes. This file size was selected based on the size of a typical JPEG image file of reasonable size. Images for one month would then produce a file of 1.7 gigabytes (40 Kb * 60 min/hr * 24 hrs/day * 30 days). A single-sided single-layer DVD is capable of holding 4.7 gigabytes of data. Though this file size is reasonable for a DVD, it is an extremely large file by internet standards and could not be sent as a typical e-mail attachment or over anything but the fastest internet connections in any reasonable amount of time.

Comments on earlier versions of the rule have suggested that much higher frame rates could be required for the image recordings. But there are tradeoffs. The basic determinants of the size of an electronic image file are its size in pixels, the bit depth for each pixel (the number of bits used to represent colors for each pixel), the number of images included in the file (determined by the frame rate and length of time), and the compression used (various different approaches are used to reduce file size, but generally at the expense of resolution).

As an example, a typical image size is 320 pixels by 240 pixels. Producing a black and white image requires a bit depth of 1 bit. To produce a good grayscale image or an image with a limited range of color requires a bit depth of 8 bits. With limited color, the file size for each frame is already 75 kilobytes (320 pixels * 240 pixels * 8 bits/pixel * 1 byte/8bits * 1
kilobyte/1024 bytes). At a frame rate of 30 frames per second (the standard video frame rate), the file size for 1 minute of video is 132 megabytes. A DVD could store 36 minutes of these uncompressed video images. This is why compression is used. The standard compression used for video was developed by the Moving Pictures Experts Group and is called MPEG. MPEG achieves good results at compression ratios up to 20:1 for video, with visual artifacts and distortion appearing at higher compression ratios. With the current example and a compression ratio of 20:1, a DVD could store about 12 hours of video images. Video images of the example size at 30 frames per second for a single flare for a month would therefore require 60 DVDs.

One participant in the August 2002 conceptual workshop also suggested requiring flare operators to put flare images on the internet. The proposed rule does not require posting of images on the internet. The District believes that the current video monitoring requirement will sufficiently provide the information the District seeks to carry out its responsibilities. Web posting, as proposed by some workshop participants and commenters, would not provide any additional benefit in determining emissions, enforcing applicable regulations, or investigating incidents. If the District receives complaints as a result of a flaring incident, an on-site investigation by an inspector would normally follow.

On May 21, 2003 following the initial hearing on the rule, which included a discussion of "webcasting" by the Board, the District convened a meeting of the flare workgroup to discuss webcasting and other issues raised at the hearing. The meeting was attended by representatives for WSPA, the individual refineries, refinery trade unions, and CBE. The consensus of all present was that webcasting raises a number of difficult issues and should be separated from the remainder of the rule and referred to the Stationary Source Committee. The staff proposal for the June 4, 2003 Board meeting reflects this consensus. To avoid imposing video recording and storage requirements that would require immediate decisions about technology that might prove to be inconsistent with later direction by the Stationary Source Committee, the District is proposing to push back the effective date of Section 12-11-507 to allow further study of webcasting and related issues. The section would be effective 180 days after rule adoption rather than 90 days to allow the necessary time for this effort.

Manual of Procedures

Provisions in the Manual of Procedures section of the rule specify test methods to be used to carry out the monitoring required by the rule.

Section 12-11-601 Testing, Sampling, and Analytical Methods

This section lists the methods that are allowed for the various approaches to composition monitoring. Section 12-11-601.1 specifies methods to be used for laboratory analysis of samples taken manually or with an auto-sampler. Section 12-11-601.2 specifies methods to be used with flame ionization detectors or non-dispersive infrared spectrophotometry. Section 12-11-601.3 specifies methods for gas chromatography. For gas chromatography, although equipment may be capable of completing cycles in 15 minutes, the allowed sampling frequency is 30 minutes, both because some refiners may want to analyze for additional compounds beyond
those required by the rule, which increases the cycle time, or because some may want to use one
gas chromatograph to analyze samples from more than one flare header.

The revised rule makes a minor change to this section to allow use of subsequent revised
versions of the listed methods.

**Section 12-11-602 Flow Verification Test Methods**

Section 12-11-402 requires a semi-annual flow verification for the flow monitors required by the
rule. As noted in the discussion of that section, this requirement simply provides a check on the
flow meters. Section 12-11-602 specifies 6 methods that can be used to measure or estimate
flow for a particular period of time. Pursuant to Section 402, the measure or estimate will then
be compared to flow monitor data for the same period. If there is a difference between the data
produced by the monitor and that produced by the verification method, it is difficult to know
whether the error lies with the meter or with alternative. The verification is primarily intended to
flag any major differences for further investigation. The verification would catch, for example,
any error in the range setting for the ultrasonic flow meter (see discussion under Section 12-11-
402). If there is a reason to suspect a problem in the flow meter, a flow meter can be removed
and bench tested with controlled flows.

The revised rule includes a requirement that measurement from the meter and the flow
verification agree to within ±20%.

Sections 12-11-602.1 and 602.2 allow pitot tube traverses as a check on flow and specify District
and EPA methods respectively for conducting these traverses. These methods involve inserting
a pitot tube into a port in a flare header and measuring flow. Though the methods have been
included, they are not likely to be used very often because of the risks involved with inserting
probes into a live flare header. Their use is also limited to velocities greater than 10 to 20 feet
per second.

Section 12-11-602.3 would allow the use of flow monitors or process monitors that can provide
comparison flow rate data for a vent stream that is flowing past the ultrasonic flow meter.

Section 12-11-602.4 would allow the use of any method recommended by the manufacturer of
the ultrasonic flow meter.

Section 12-11-602.5 would allow the use of a tracer gas to determine flow. A tracer gas can be
introduced into a flare header through a port upstream of a second port at which vent gas is
sampled for presence of the tracer gas. By timing how long it takes the tracer gas to move from
the port where it is introduced to the port where it is detected or by measuring the tracer gas
concentration, flow velocity can be determined.

Section 12-11-602.6 would allow any alternative method if approved by the District and EPA.
EMISSIONS REDUCTIONS

The purpose of Regulation 12, Rule 11, Flare Monitoring at Petroleum Refineries is to gather information on flaring including flow, composition, and cause. The proposed rule does not mandate reductions. Nevertheless, District staff have found that because refiners have looked more closely both at monitoring and the feasibility of flaring reductions, flaring at the five Bay Area refineries has dropped dramatically over the past year. One refinery has installed new compressors that have allowed it to go from flaring an average of 5 million standard cubic feet of vent gas per day to virtually zero routine flaring. The result has been a significant emission reduction that cannot be directly attributed to this rule, but will ultimately be reflected in the emissions inventory.

ECONOMIC IMPACTS

Costs

The proposed rule requires the installation of 3 types of monitoring equipment: (1) flow monitoring equipment, (2) composition monitoring equipment, and (3) video monitoring equipment. Because the rule allows each refinery options, particularly in determining how to monitor vent gas composition, it is difficult to predict cost for each refinery. Cost will also vary because the number of flares at each refinery varies. Costs are divided into two main categories: (1) initial capital and installation costs for equipment, and (2) annual operating and maintenance costs.

Table 5. Capital Cost Items

<table>
<thead>
<tr>
<th>Cost Item</th>
<th>Cost</th>
<th>Comment</th>
</tr>
</thead>
<tbody>
<tr>
<td>Flow monitor</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Ultrasonic meter w/ installation</td>
<td>$50,000</td>
<td></td>
</tr>
<tr>
<td>Annual amortized cost</td>
<td>$6164</td>
<td></td>
</tr>
<tr>
<td>Continuous analyzer (NDIR)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Hydrocarbon analyzer</td>
<td>$9,000</td>
<td>2 analyzers: (1) dual channel-methane and total hydrocarbon, (2) H₂S</td>
</tr>
<tr>
<td>H₂S analyzer</td>
<td>$15,000</td>
<td></td>
</tr>
<tr>
<td>Sample conditioning</td>
<td>$40,000</td>
<td></td>
</tr>
<tr>
<td>AutoCal system</td>
<td>$25,000</td>
<td></td>
</tr>
<tr>
<td>Installation</td>
<td>$50,000</td>
<td></td>
</tr>
<tr>
<td>Total</td>
<td>$139,000</td>
<td></td>
</tr>
<tr>
<td>Annual amortized cost</td>
<td>$17,137</td>
<td></td>
</tr>
<tr>
<td>Continuous analyzer (FID)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Hydrocarbon analyzer</td>
<td>$12,000</td>
<td>2 analyzers: (1) dual channel-methane and total hydrocarbon, (2) H₂S</td>
</tr>
<tr>
<td>H₂S analyzer</td>
<td>$15,000</td>
<td></td>
</tr>
<tr>
<td>Sample conditioning</td>
<td>$40,000</td>
<td></td>
</tr>
<tr>
<td>AutoCal system</td>
<td>$25,000</td>
<td></td>
</tr>
<tr>
<td>Installation</td>
<td>$50,000</td>
<td></td>
</tr>
<tr>
<td>Total</td>
<td>$142,000</td>
<td></td>
</tr>
<tr>
<td>Cost Item</td>
<td>Cost 1</td>
<td>Comment</td>
</tr>
<tr>
<td>----------------------------</td>
<td>--------</td>
<td>--------------------------------</td>
</tr>
<tr>
<td>Annual amortized cost 2</td>
<td>$17,507</td>
<td></td>
</tr>
<tr>
<td>Continuous analyzer (GC)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>GC</td>
<td>$50,000</td>
<td></td>
</tr>
<tr>
<td>Sample conditioning</td>
<td>$40,000</td>
<td></td>
</tr>
<tr>
<td>Installation</td>
<td>$50,000</td>
<td></td>
</tr>
<tr>
<td>Total</td>
<td>$140,000</td>
<td></td>
</tr>
<tr>
<td>Annual amortized cost 2</td>
<td>$17,261</td>
<td></td>
</tr>
<tr>
<td>Auto-sampling system</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Auto-sampler</td>
<td>$15,000</td>
<td></td>
</tr>
<tr>
<td>Installation</td>
<td>$15,000</td>
<td></td>
</tr>
<tr>
<td>Total</td>
<td>$30,000</td>
<td></td>
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<tr>
<td>Annual amortized cost 2</td>
<td>$3,699</td>
<td></td>
</tr>
<tr>
<td>Manual sampling station</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Installation</td>
<td>$10,000</td>
<td></td>
</tr>
<tr>
<td>Annual amortized cost 2</td>
<td>$1,233</td>
<td></td>
</tr>
<tr>
<td>Video monitoring</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Equipment w/installation</td>
<td>$5,000</td>
<td></td>
</tr>
<tr>
<td>Annual amortized cost 2</td>
<td>$616</td>
<td></td>
</tr>
</tbody>
</table>

1 Costs based on vendor estimates or quotes to ARB or District staff
2 Costs amortized over 10 years @ 4% real interest rate

Table 6. Annual Operating Costs

<table>
<thead>
<tr>
<th>Cost Item</th>
<th>Cost</th>
<th>Comment</th>
</tr>
</thead>
<tbody>
<tr>
<td>Maintenance for all monitors (per flare)</td>
<td>$20,000</td>
<td>District estimate</td>
</tr>
<tr>
<td>Sample analysis</td>
<td>$500/sample</td>
<td>Vendor quote</td>
</tr>
<tr>
<td>Report preparation per flare 1</td>
<td>$4,000</td>
<td>Costs based on 1 day of labor @$50/hr/flare/month</td>
</tr>
</tbody>
</table>

Based on the above cost estimates, the annual cost per flare will depend upon the flare monitoring technologies chosen, but the cost is expected to be about $50,000 per flare. For flares for which composition is monitored by sampling, equipment costs are lower but sample analysis costs bring total cost up to a level comparable to that for flares using continuous analyzers.

At an annual cost of $50,000 per flare, the total cost for the Bay Area refineries together is expected to be about $1.15 million per year. The cost per refinery will depend upon the number of flares at the refinery.
Socioeconomic Impacts

Section 40728.5 of the Health and Safety Code requires an air district to assess the socioeconomic impacts of the adoption, amendment, or repeal of a rule if the rule is one that “will significantly affect air quality or emissions limitations.” The proposed rule is intended to provide the tools necessary to analyze refinery flaring. It would impose monitoring requirements for refinery flares but would not impose emission limitations. As a result, these limits cannot be said to “significantly affect air quality or emission limitations,” within the meaning of Section 40728.5, and the District will not prepare the socioeconomic analysis that would otherwise be required under Section 40728.5 of the Health and Safety Code. However, the District has attempted to minimize the costs imposed by the proposed rule.

Incremental Costs

Under Health and Safety Code Section 40920.6, the District is required to perform an incremental cost analysis for a proposed rule under certain circumstances. To perform this analysis, the District must (1) identify one or more control options achieving the emission reduction objectives for the proposed rule, (2) determine the cost effectiveness for each option, and (3) calculate the incremental cost effectiveness for each option. To determine incremental costs, the District must “calculate 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.” Because the proposed rule does not impose control requirements, no incremental cost analysis will be prepared.

ENVIRONMENTAL IMPACTS

Pursuant to the California Environmental Quality Act, the District prepared an initial study for the proposed rule to determine whether rule adoption would result in any significant environmental impacts. The rule is intended to allow the District to collect data on refinery flaring through the imposition of monitoring requirements. Because the rule would not impose emission control requirements, which always have some potential to alter emissions or transfer them from one media to another, and because any necessary construction would take place within existing refineries, no adverse environmental impacts are expected. The study did identify the construction work required to install monitors as a source of potential environmental impacts. However, because of the safety requirements that govern this type of work, the regularity with which similar hot work is conducted in refineries, and the consequent familiarity with and preparedness for this type of work on the part of refinery workers and contractors, the study concluded that the proposed rule would not result in any significant environmental impacts through this mechanism.

A CEQA Negative Declaration is proposed for adoption by the Board in connection with the adoption of the revised rule. The CEQA document was circulated for public comment during the period from April 21, 2003 to May 12, 2003. No comments on the document were received.
REGULATORY IMPACTS

California Health and Safety Code Section 40727.2 require the District to identify existing federal air pollution control requirements for the equipment or source type affected by the proposed rule or regulation. The District must then note any differences between these existing requirements and the requirements imposed by the proposed rule. Table 7 is a matrix of the proposed rule, existing Bay Area regulations, and federal requirements for flares.

Table 7: Comparison of Regulatory Requirements

<table>
<thead>
<tr>
<th>Agency</th>
<th>Regulation</th>
<th>Control/Performance Requirements</th>
<th>Monitoring Requirements</th>
<th>Emission Limitations</th>
</tr>
</thead>
<tbody>
<tr>
<td>BAAQMD</td>
<td>Reg. 2, Rule 6 (Title V permit)</td>
<td>Specific to facility and source</td>
<td>Specific to facility and source</td>
<td>Throughput limits, visible emission</td>
</tr>
<tr>
<td>BAAQMD</td>
<td>Proposed Reg. 12, Rule 11</td>
<td>No</td>
<td>Volumetric flow and composition</td>
<td>No</td>
</tr>
<tr>
<td>EPA</td>
<td>40 CFR 60.18 (applies to flares subject to NSPS)</td>
<td>Pilot flame present at all times, heat content, maximum tip velocity, sulfur content</td>
<td>Presence of flame, heating value</td>
<td>Smokeless capacity</td>
</tr>
</tbody>
</table>

Federal Requirements

Federal New Source Performance Standards (NSPS) in 40 CFR Part 60, Subpart A, Section 60.18 apply to flares that are used as general control devices. They specify design and operational criteria for new and modified flares. The requirements include monitoring to ensure that flares are operated and maintained in conformance with their designs. Flares are required to be monitored for the presence of a pilot flame using a thermocouple or equivalent device. Other parameters to be monitored include visible emissions, exit velocity and net heat content of the gas being combusted by the flare.

In addition, the NSPS limit sulfur oxides in vent gases combusted in a flare installed after June 11, 1973 (40 CFR Part 60, Subpart J, Section 60.104). Upset gases or fuel gas that is released to the flare as a result of relief valve leakage, startup/shutdown, or other emergency malfunctions is exempt from the standard.

District Requirements

Within the District, a new emission source or a modified existing source must meet the District’s New Source Review (NSR) requirements. The NSR program requires the use of Best Available Control Technology (BACT) for new or modified sources that have the potential to emit 10 pounds per day or more of VOC, carbon monoxide, oxides of nitrogen, particulate matter, or
sulfur dioxide. For flares, BACT requires a control efficiency of 98% for elevated flares and 98.5% for ground flares. Other permit conditions are imposed on some flares. These conditions may include throughput limits and record keeping to document compliance.

The proposed rule would require continuous monitoring for volume and sampling or the use of continuous analyzers for vent gas composition. Recording of video images of flares would be required. Monthly reports of flow, composition, and other data would be required. For larger releases (over 1 million standard cubic feet per day), a report on the time, cause, duration, and reason for the flaring would be required.

**RULE DEVELOPMENT HISTORY**

The District has been carrying out a complex study of flares and flaring at the Bay Area refineries since January 2002. The study implements further study measure FS-8 from the 2001 Bay Area Ozone Attainment Plan. In the course of the study, District staff have visited all five Bay Area refineries numerous times, have met with refinery staff, ARB and EPA staff, and with community groups in over 50 meetings to discuss issues related to flaring.

A work group was formed to carry out the further study. The workgroup included representatives from California Air Resources Board, Industry, Communities for a Better Environment, and District Staff. The Environmental Protection Agency and other air districts, including the South Coast AQMD and the San Joaquin Valley Unified APCD participated at various levels throughout the project. The workgroup has met periodically since January 2002 to discuss technical issues. Among those issues have been flare monitoring issues such as flow monitoring and available technologies and composition monitoring methods.

In May 2002, the District conducted an informational public meeting to gather input on the District’s plans to implement the commitments in the ozone attainment plan. In August 2002, District staff held a workshop in Martinez to discuss flare monitoring concepts. At this workshop, community members indicated that they would like to see a rule that required flow monitoring, composition monitoring, reporting requirements, and video monitoring.

Three community meetings were held in March and April 2003. After the community meetings, a draft rule was circulated for a short comment period ending April 17, 2003. Extensive comments were received from WSPA, Communities for a Better Environment, and refinery trade unions. On April 16, 2003, the proposed rule was discussed before the Stationary Source Committee. A flare workgroup meeting was then held on April 18, 2003. The meeting was attended by representatives for various refineries, WSPA, CBE, the refinery trade unions, monitoring equipment vendors, ARB, and District staff. Based on the draft and these further discussions, the proposed rule was developed and sent to the Air Resources Board on April 21, 2003. Discussions continued on May 8, 2003 with a second flare workgroup meeting. After the second meeting, modifications to the proposed rule were developed and circulated among all who participated in the meeting. After discussion with members of the workgroup, staff prepared the revised rule.
DISTRICT STAFF IMPACTS

Implementation of the proposed regulation will have a significant impact on the District’s resources. However, these changes are essential and necessary in order to satisfy the commitments in the Bay Area 2001 Ozone Attainment Plan.

The proposed regulation will require the installation of monitors. The District will have to exercise oversight for these monitors in a manner similar to that used to oversee continuous emission monitors (CEM). The resources required are similar, and will require District staff to verify the installation of monitoring equipment, conduct accuracy tests or ensure that they are conducted, review monthly reports, perform compliance inspections, and investigate flaring incidents.

Monthly reports on flaring will be required. These reports will have to be reviewed by District staff. The District expects to continue to investigate significant flaring events. This would not represent a change from the model used in the further study measure for flares. A flaring event was defined for the study as any flow over 1,000,000 standard cubic feet per day to a flare. The rule requires an investigation that is included in the monthly report from the refinery whenever daily volume exceeds 1,000,000 standard cubic feet. During the further study period, the time required to investigate events varied, was dependant on the complexity of operations, and ranged from less than an hour to hundreds of hours. This workload will diminish as flaring decreases (as it is currently) and as more data becomes available with new monitors in place.

CONCLUSION

Proposed Regulation 12, Rule 11, Flare Monitoring at Petroleum Refineries, will implement control measure SS-15 from the Bay Area 2001 Ozone Attainment Plan. The rule is intended to gather data on flaring operations at petroleum refineries.

Pursuant to the Health and Safety Code Section 40727, new regulations must meet necessity, authority, clarity, consistency, non-duplicity and reference. The proposed regulation is:

- Necessary to implement control measure SS-15 in the Bay Area 2001 Ozone Attainment Plan;
- Authorized by California Health and Safety Code Section 40702;
- Clear, in that the new regulation specifically delineates the affected industry, compliance options and administrative requirements for industry subject to this rule;
- Consistent with other District rules, and not in conflict with state or federal law;
- Non-duplicative of other statutes, rules or regulations; and
- The proposed regulation properly references the applicable District rules and test methods and does not reference other existing law.
REFERENCES


California Air Resources Board (CARB). CARB Board Resolution No. 86-80. Sacramento, CA.


COMMENTS AND RESPONSES

The following written comments were received during the rule development process for the proposed flare monitoring rule. These comments and responses refer to the rule prepared and made available with the public notice for the May 21st hearing as the “proposed rule.” This is in keeping with standard terminology used by ARB, air districts, and the Health and Safety Code (§§40725, 40726). The revised version of the rule now proposed for adoption is called the “revised rule.” Earlier drafts of the rule are called “earlier drafts.” These comments were made on an earlier draft that preceded the proposed rule. Many of the comments were addressed in the proposed rule or in the revised rule that staff is recommending for adoption by the Board.

Written Comments Received During Community Meetings

The District held three community meetings in March and April 2003 to discuss rule concepts. During or after these meetings, the District received the following written comments related to an earlier rule draft.

1. The draft rule allows refineries to choose once per day sampling and skip monitoring gas composition for the rest of the day. Refineries are only required to sample gas composition during 60 minute periods exceeding 50,000 cubic feet of gases flowing to the flare. This loophole allows each flare to skip monitoring the gas composition of over a million cubic feet per day of gases (49,000 cubic feet x 23 hours). <May, Communities for a Better Environment (CBE). E-mail. 3/27/03>

For the sampling option to which the comment refers, the earlier draft rule set a trigger that required sampling when the volume of vent gas measured during a 60-minute period exceeded 50,000 standard cubic feet of gas. Based in part on a concern expressed in earlier comments, the trigger was revised downward in the proposed rule and subsequently in the revised rule now recommended for adoption. The revised trigger that staff recommend is identical to the trigger in the South Coast AQMD rule (which requires sampling when flows continuously exceed 330 cubic feet per minute for 15 minutes).

Note that all vent gas must be monitored for flow volume regardless of the means used to determine composition. If sampling is used for monitoring vent gas composition, it is important that the trigger be set at some minimum flow that represents actual flow to the flare so that false positive readings are avoided. The earlier draft rule to which this comment was directed set a trigger that was based on an assumption that ultrasonic flow meters could not reliably measure flare flows at below 1 foot per second. The revised trigger is based on an assumption that there is adequate reliability even at approximately 0.5 foot per second.
As discussed in the staff report (see discussion of Section 12-11-502), large flare headers are subject to various effects that produce low velocity currents within the header that do not represent flow to the flare. With a trigger lower than approximately 0.5 foot per second, meter accuracy is lower, and low-velocity flows that do not represent flow to the flare may be encountered. The result is that flow may be indicated where none exists (i.e., a false positive flow). If samples are then taken, these “no flow” samples will bias results.

2. The draft rule allows huge flows of gases to go unmonitored because the refineries are allowed to skip measuring flows below 0.5 ft./sec. <May, CBE. 3/27/03>

The rule requires all flows to be measured and reported (see Section 12-11-401). The comment is a response to Section 12-11-501, which specifies a series of requirements for any device used to measure flow. One of the specifications is that the meter must measure the range of flow corresponding to velocities from 0.5 to 275 feet per second. This is a device specification and not a limitation on the reporting otherwise required by Section 12-11-401. An ultrasonic meter that meets the specification is capable of reporting data on flow down to its limit of detection. The specification is derived from literature from Panametrics. The Panametrics meter is capable of detecting flow down to 0.1 feet per second. As noted above, however, these low velocity flows may not represent flow to the flare.

3. The draft rule allows poor quality assurance procedures, such as “engineering calculations” or “other flow monitoring devices or process monitors” for determining whether [flow] monitoring equipment is working right. <May, CBE. 3/27/03>

Ultrasonic flow meters are state-of-the-art devices for measuring flow. They are extremely accurate over a wide range of flows, are robust with no moving parts, and are proven in service. They are widely used as custody transfer meters to price large volumes of natural gas at sale. Section 12-11-506.3 already requires proper calibration and maintenance. The verification procedures included in the rule are inevitably less accurate means of measuring flow, but are included in the rule as a check on the meters to avoid gross errors such as might come from misinterpreting the range setting or units represented by the meter display or output.

Written Comments Received During Written Comment Period

Following the completion of the community meetings, the District prepared a revised draft and made it, a draft staff report, and a draft CEQA initial study available for public comment. The comment period ran from April 7 – 17, 2003. The following comments were received.
4. **What data/monitoring is needed for proposing rule-making?** <Partnership for Public Health, Environmental Health Committee (PPH). 4/16/03>

For any rulemaking, the District must make a number of findings required by California Health and Safety Code section 40727. Findings of necessity and authority are among the required findings. For this rulemaking (flare monitoring), this staff report serves as the basis for the necessary findings.

5. **What is the nature of the discrepancies between the Air District assessment and the assessment from the refineries? How will these discrepancies be addressed? What is the avenue for meaningful public participation in this process?** <PPH. 4/16/03>

The major differences between the District's Draft Technical Assessment Document and data submitted by the refineries are in the hydrocarbon content and volume of gases flared. These differences will be addressed through the ongoing technical assessment process for flares. The public can participate through the flare work group or by commenting on the technical assessment document as revised.

6. **Is routine flaring legal? If not, what does the Air District plan to do about these flares (i.e.; fines, cease and desist orders, control measures).** <PPH. 4/16/03>

Under certain circumstances routine flaring may result in a violation of Federal standards (40 C.F. R. Section 60.104(a)(1)). Such a determination is based upon the factual circumstances in any given flaring event. Because the purpose of the current regulation is to gather data and monitor emissions, this question may be better answered in another forum.

7. **What monitoring technology is currently available? What is the best way to monitor?** <PPH. 4/16/03>

For flare gas flow rate (cubic feet per minute of gas vented to the flare), the current state-of-the-art monitoring technology is ultrasonic flow meters. For flare gas composition, there are various methods, including taking grab samples to be analyzed in a laboratory, continuous gas chromatographs that collect and analyze a sample every 15 minutes, and continuous monitors that measure methane, total hydrocarbons, and sulfur compounds. There are advantages and disadvantages for each monitoring method. Grab sampling and subsequent lab analysis is simple but labor intensive, provides a “snapshot” of composition for the instant when it was taken, but is not available until hours after the sample was taken. Continuous gas chromatographs are complicated, require complex sample conditioning systems, may need much maintenance, but provide very detailed composition information every 15 minutes. Continuous monitors for methane, total hydrocarbons, and sulfur compounds also require complex
sample conditioning systems but provide continuous composition information for these compounds.

8. What does monitoring tell us from an exposure standpoint and from a health effects standpoint? That is, how much exposure is the community getting and is this harmful to the health of the community members? Is there any additional concern for those who are chronically ill, are chemically sensitive, the young and the elderly? <PPH. 4/16/03>

Flare monitoring for flow rate and flare gas composition will provide data that can be used to calculate emissions. Dispersion models can be used to calculate the air quality impact of the flare emissions. These air quality impacts can then be used to estimate exposure. Health professionals can evaluate the health impacts. Generally speaking, young children, the elderly, and those with respiratory illness are more sensitive to air pollution than healthy adults.

9. Are all flares monitored? For instance, are there records of specific dates and times of flaring incidents over the last few months? <PPH. 4/16/03>

The information available today is limited. The District has been conducting a study of flaring with the available data and has posted on its website (www.baaqmd.gov) preliminary flaring data covering the period from January 2001 to August 2002. This data is preliminary and in many cases relies upon assumptions that may be revised. With new flare monitoring technology, much more reliable information will be available.

10. When flares are monitored, how quickly is the monitoring information available to residents? What is the Air District plan for public notification? <PPH. 4/16/03>

Refineries will be required to provide the District with a monthly report for each flare that will include flow and composition data. The District has not yet determined how best to provide this information to the public, but is considering the use of its website and perhaps other means.

11. What is the breakdown of the emissions? What specific chemicals are monitored and what chemicals that are emitted are not monitored? Why aren’t all chemicals monitored? <PPH. 4/16/03>

Emissions come from two primary mechanisms: oxidation of flare gases to other compounds and incomplete combustion that allows a small portion of the flare gas to pass through the flare uncombusted. Flare gas is generally composed primarily of methane, non-methane hydrocarbons, nitrogen, and hydrogen with small amounts of other compounds, including sulfur compounds. The primary combustion products are carbon dioxide and water, but sulfur compounds are oxidized to oxides of sulfur. The flare monitoring rule focuses on composition monitoring for methane, total hydrocarbons, and sulfur compounds because
these compounds form ozone and sulfur dioxide, and health-based ambient air standards have been established for both pollutants.

12. **How long will it be before the Air District implements measures that will reduce the amount of pollution being discharged by flares?** <PPH. 4/16/03>

The District is currently completing its study of flares and expects to determine by summer how it will move forward to reduce flaring. The refineries have already significantly reduced flaring from 2001 and 2002 levels.

13. **How will the information and input be gathered from this and other meetings and from monitoring be used in rule-making regarding flaring? What is the timeline for rule-making? How can residents be involved in this process?** <PPH. 4/16/03>

Information provided from the public through the comment period, public hearings and other submittals and meetings have been considered in drafting the District's final monitoring proposal. We are still working on the flare study that will determine the next steps regarding potential controls on flares. Though the data we have developed through the study may not have the precision of the data that will come from the new monitors, it should be adequate to guide the District's decision about controls. The District expects that, if the study concludes that controls are available, the rule development effort to impose controls would be concluded by the end of 2003. The District will again consider comments that have already been received regarding controls, and residents will again be invited to participate and comment in the flare control rulemaking process.

14. **Are you documenting each of our questions? How are you going to respond to the community concerns?** <Asthma Community Advocate (ACA). 4/16/03>

The District is considering all comments and responding to all written comments. The proposed rule incorporates many community suggestions.

15. **Will there be a timeline for creating and implementing the rule?** <ACA. 4/16/03>

The District Board of Directors will conduct a public hearing on May 21, 2003 at which it will consider adoption of the rule.

16. **Are there any consequences for the refineries if the designated timeline is not maintained? (fines, etc.)** <ACA. 4/16/03>

Yes. Failure to meet rule requirements would be a violation of the rule subject to potential enforcement action and penalties.
17. Are the refineries going to be allowed to continue to use flares for planned and routine use? <ACA. 4/16/03>

The proposed flare monitoring rule does not impose restrictions on flare use. Consideration of flare controls is a separate process. See response to comment #13.

18. How will non-accidental uses of flares be regulated and monitored? <ACA. 4/16/03>

The proposed rule would require monitoring of all flaring events from flares subject to the rule, accidental or not. Also see response #17.

19. How will the public know what measures refineries are taking to implement technologies to reduce the need for flares in the first place? <ACA. 4/16/03>

Section 12-11-401 of the proposed rule requires that monthly reports on flaring include a description of any measures taken to reduce or eliminate flaring.

20. How will this information be provided to the community? <ACA. 4/16/03>

See response #10.

21. Do the refineries have to wait to implement pollution controls until this flare rule is developed? <ACA. 4/16/03>

No. One refinery has installed new compressors that allowed it to virtually eliminate routine flaring. Most of the refineries now have compressors that should allow them to avoid routine flaring. Nothing in this rule prevents refineries from moving forward with flare controls.

22. Why isn’t the Air Board monitoring for hydrogen and nitrogen? <ACA. 4/16/03>

Hydrogen and nitrogen in the flare gas do not contribute directly to air pollution. When hydrogen is burned in a flare, it is converted to water. Flares use surrounding air to provide the oxygen for combustion. Air is about 20% oxygen and 80% nitrogen by volume. While a small amount of nitrogen in the air is converted to nitrogen oxides, which can contribute to ozone formation, nitrogen in flare gas would not increase emissions of nitrogen oxides.

23. Don’t wait to implement pollution controls to reduce the need for flares-planned, routine or accidental! <ACA. 4/16/03>

See responses #13 and #21.
24. **How is the public going to be notified about the findings of the flares? In real time? In plain English? What about the findings of the report?** <ACA. 4/16/03>

Information about major flaring events is posted on the District's website. The monthly reports on flaring that are required by the proposed rule will be available to the public (see response #10). The flare study as revised will be available on the District website.

25. **We feel that someone from the West County Asthma Coalition should be kept updated on a routine basis by the Air Board about the flare issue.** <ACA. 4/16/03>

See response #24. We are happy to discuss flaring issues with the West County Asthma Coalition.

26. **We recommend requiring continuous analyzers for vent gas monitoring. If there is a malfunction of that equipment then manual sampling should be used.** <ACA. 4/16/03>

Continuous analyzers are an allowed option. Other options are allowed because continuous analyzers have never been installed on refinery flare headers, and the feasibility of this approach is not yet known.

27. **What are penalties or consequences if the monitoring requirements are not met?** <ACA. 4/16/03>

Failure to comply with the monitoring requirements would be a rule violation subject to potential enforcement action and penalties.

28. **We understand that the positioning of the camera could influence the reading of the emissions from refineries. So, is it possible to have more than one video recording device monitoring flares? There should be a time and date stamp.** <ACA. 4/16/03>

Cameras cannot be used to read emissions from flares. The rule requires monitoring of flow and composition using flow meters and other means that provide more reliable information than cameras. Cameras provide secondary information about the size and shape of the flame that cannot be used to determine the nature and quantity of emissions. The rule specifies minimum requirements for video monitoring. More than one camera would be allowed but not required. The proposed rule requires a time and date stamp.

29. **Flare images should be retained for at least 7 days, as opposed to a minimum of 72 hours. We understand that storage has come up as an issue, but how big an inconvenience is too big an inconvenience to store small video digital tapes?** <ACA. 4/16/03>
The proposed rule now requires that the flare images for each month be recorded and submitted to the District. Tapes are not a reliable storage means. It is expected that video information would be converted to digital files and archived on DVDs or other storage media.

30. Are video tapes going to be fully accessible to the public? Since this is public information, can it be available at public libraries or other public places, so the public won’t have to necessarily go through a government agency for access to the videos? <ACA. 4/16/03>

It is unlikely that tapes will be used. It is more likely that images will be digitally recorded on DVDs or other media that can be read by computers. The District has not yet decided how to make the data available.

31. Periodically, will public sharing of flaring videos be scheduled and presented in plain English? We recommend that if the Air Board is given 24 hours notice, than any member of the public should be allowed to see any video. <ACA. 4/16/03>

See response #30.

32. How many years are you going to collect data before you require changes in industrial practices leading to a reduction in flares? <ACA. 4/16/03>

See responses #12 and #13.

33. What is your proof or data, that flare emissions are not impacting the health of the local community? <ACA. 4/16/03>

All air pollutants have the potential to affect health, particularly for the young, the elderly, and those with respiratory illness. Flares are just one of many contributors to air pollution. Many other sources, including cars and trucks, contribute emissions, including sulfur emissions, that are similar to those from flares. Given that these flare emissions are not unique and that the causes of asthma, cancer, and many other illnesses are not well understood, it is unlikely that flare emissions can be identified as being responsible for a particular health problem. Nor can it be proved that they are not responsible. In general, it is well known that ozone and sulfur dioxide can, for example, trigger asthma attacks. As a result, the District works to reduce these pollutants, regardless of the source.

34. Is there any proof that sulfur emissions from flares have no harmful health effects? <ACA. 4/16/03>

See response #33.
35. In general, sulfur components trigger asthma, what proof do you have that sulfur emissions from flares have no harmful health effects? <ACA. 4/16/03>

See response #33.

36. The short comment period has hampered our ability to thoroughly review the proposed rule. We strongly support a thorough and vigilant flare monitoring rule. We also support the detailed comments on this rule submitted by Communities for a Better Environment. <Holtzclaw, Sierra Club. E-mail. 4/17/03>

The District understands the difficulty. The District is moving quickly to establish a flare monitoring rule that is thorough and responsive. Given the District's desire for an expeditious and efficient process, the additional comment period was necessarily short.

37. We believe that web-posted video monitoring on real-time basis is necessary to establish and maintain a common tool for community, regulators and regulatees to reference in their communications. We urge the District to require that real time flare images be posted so that nearby folks can monitor the flares along with regulators and refinery personnel. With 24 hour real time video monitoring that is accessible, it may be possible to identify which wind and release conditions result in troubling air quality. <Holtzclaw, Sierra Club. 4/17/03>

The proposed rule does not require web posting for the reasons discussed in the staff report (see discussion of Section 12-11-507). The flow and composition monitoring requirements of the rule are a much more reliable source of the information that would be necessary to assess air quality impacts.

38. The exemption of Section 12-11-111 should include thermal oxidizers. Thermal oxidizers are highly efficient control devices, therefore all thermal oxidizer applications should be exempt from this rule. <Buchan, Western States Petroleum Association (WSPA). E-mail. 4/17/03>

Thermal oxidizers are by definition exempt from the rule, but the exemptions of Sections 12-11-110, 112, 113, and 114 have been modified to make this clear.

39. Modify the definition of "flare" to clarify the difference between flares and other combustion equipment. <Buchan, WSPA. 4/17/03>

The definitions of "flare" and “thermal oxidizer” have been modified to accomplish this.

40. A definition for “flare monitoring systems” is needed to identify all monitoring equipment that could fail and, therefore, come under the
equipment malfunction requirements of section 506.1. <Buchan, WSPA. 4/17/03>

The District has added a definition and clarified the monitor downtime provisions of Section 12-11-506.1.

41. A definition for “day” is needed to clarify its usage throughout the regulation. We believe that a calendar day would simplify various recordkeeping requirements and is appropriate. <Buchan, WSPA. 4/17/03>

The rule does not include the definition. Section 12-11-401.6 requires a "root cause" analysis if more than 1 million standard cubic feet of gas are flared in a 24-hour period. This analysis would be required when flaring begins in the evening, and the 1 million standard cubic foot threshold is reached after midnight. Use of "day" instead of "24-hour period" would mean no analysis would be required under these circumstances.

42. Changing the report due date to the end of the following month aligns the deadline for the flare reporting with several other monthly report deadlines so the reports can be submitted together. <Buchan, WSPA. 4/17/03>

Section 12-11-401 has been modified to include this deadline.

43. Adding an “(s)” to the reference [in Section 12-11-401] to flare headers clarifies the reporting requirements for flare systems with one or more headers feeding the same cascading or staged flare system. <Buchan, WSPA. 4/17/03>

Section 12-11-401 has been modified to make it clear that only one report is required for such a system rather than individual reports for each flare in the system.

44. Deletion of requirements for hourly data in section 401.1 and 401.3 is proposed because we believe that hourly data is overly burdensome and is not needed to determine emissions from the flares. <Buchan, WSPA. 4/17/03>

Hourly data will be generated by the monitors and can be easily provided in electronic format. During large flaring events, emissions can change significantly from hour to hour.

45. Changes to section 401.4 are proposed to simplify the wording regarding purge gas data in the monthly report. <Buchan, WSPA. 4/17/03>

The District believes the proposed language is clear. The suggested language would allow submission of daily averages under circumstances where more detailed data is available. Where purge gas use is at a fixed rate, it would be permissible with our language to submit the daily average.
46. Changes are proposed in section 401.6 to clarify the accumulation time for the 1.2 million standard cubic feet of vent gas and a requirement for hourly flow during such periods was added to ensure adequate data is collected for such flaring events. <Buchan, WSPA. 4/17/03>

See response #41.

47. The use of a 24-hr period unnecessarily compounds the data capture and reporting task. Instrument data is normally archived and presented in a simplified midnight to midnight basis. The use of another 24-hr period will require the execution of additional manual tasks that may result in a loss of the data automation accuracy from flow recording systems. Additionally, routine duties such as monitoring of flare event periods should match as closely as possible, the normal work routines and schedule of refinery personnel. The introduction of a task that is triggered by an unpredictable monitoring activity will require additional task execution by the operators. <Buchan, WSPA. 4/17/03>

See response #44. Flow monitor data loggers can be easily programmed to recognize when the threshold has been reached. With either the proposed language or the WSPA language, the threshold could be reached at any hour of the day.

48. We are willing to provide emissions calculations on using the 98% control efficiency basis. However, we wish to note that there are several studies that indicate that the flare hydrocarbon destruction efficiencies are typically higher than 98%. Therefore, the emission calculations will very likely be overestimating the actual flare hydrocarbon emissions. This fact should be taken into account when considering possible uses for these emission numbers. <Buchan, WSPA. 4/17/03>

Comment noted.

49. [In Section 12-11-501,] the minimum velocity should be 0.5 feet per second(fps) or 0.34 MPH. Based on our experience and the experience in the SCAQMD, a 0.5 fps zero cutoff will create false vent gas flow readings. These false readings are primarily caused by eddy currents and temperature changes within the flare stack. Due to the sensitivity of the flow meter at this very low flow setting, gas expansion due to daily changes in ambient temperature will result in signals of non-existent vent gas flows. Upon receiving these false signals, the operator must then monitor and report these “ghost” flows per 12-11-401 on a daily basis. To avoid this unnecessary low flow indication and subsequent reporting of these miniscule false flows and false emissions, we request that the minimum velocity be 0.5 fps. <Buchan, WSPA. 4/17/03>
The rule specifies that the flow monitoring device must continuously measure flow velocity from 0.5 to 275 feet per second because this is the range over which ultrasonic flow meter manufacturers (Panametrics and Roxar) guarantee highest accuracy. But Section 12-11-401 requires continuous flow monitoring and reporting of all flow data, not just flows above 0.5 foot per second.

50. The requirement in Section 501.3 that the flow monitoring device continuously measure molecular weight should be to allow maximum flexibility in the type of flow meter used. Currently, the most likely type of flare flow meter does allow a continuous measurement of molecular weight. However, other acceptable flow monitoring instruments may become available and the molecular weight requirement may prevent use of any other flow instruments, limiting the flow monitoring to a single supplier. <Buchan, WSPA. 4/17/03>

This requirement has been removed from Section 12-11-501. Section 12-11-401.4 now specifies that this information must be reported if available from the meter.

51. Section 502.2 does not allow enough time to properly design, review, order, and construct a safe sampling system. The section should be changed to allow 90 days. <Buchan, WSPA. 4/17/03>

The section now allows 90 days rather than 60.

52. The minimum sampling frequency of once per day [in Sections 502.2 and 502.3] does not make sense if there is no flow. <Buchan, WSPA. 4/17/03>

We have eliminated the requirement for daily sampling in favor of a trigger that would require sampling only when there is flow to the flare.

53. The rate [of 50,000 standard cubic feet in one hour] triggering sampling and the frequency of sampling required [every 3 hours] seems excessive. We propose increasing the trigger for frequent sampling to a 100,000 standard cubic feet event in one hour. This would still identify very small events (less than 50 pounds of hydrocarbon using typical vent gas composition). Sampling even smaller events would not provide any significant information and would significantly increase the cost for sampling and analysis. In addition, it would allow operators to focus on stopping even small flaring events rather than concentrate on verifying that samples have been taken for insignificant events. Also, we propose that the frequency for sampling such events should be reduced to once every 8 hours. Generally, the vent gas composition during a flaring event does not change significantly over a period of 8 hours. Therefore, a sampling frequency of once every 8 hours should be adequate. <Buchan, WSPA. 4/17/03>
In the proposed rule, the trigger for sampling was set at 6,000 standard cubic feet in 15 minutes. However, staff is now recommending that the trigger be modified to be identical to the trigger used in the South Coast AQMD rule (330 standard cubic feet per minute continuously for 15 minutes). This change is included in the revised rule.

To address community concerns that a sampling interval measured in hours would mean that composition would go unmonitored for too long during flaring events, the proposed rule specified integrated sampling at 15 minute intervals. Integrated sampling produces a composite sample out of aliquots (portions of the total sample size). Because the aliquots are taken over time, the sample reflects variation in composition that may occur over time. However, because this eliminated conventional sampling and meant that expensive sampling equipment or continuous analyzers would be required for numerous flares that are rarely used, recommended changes are included in the revised rule to add back a conventional sampling option with a sampling interval of three hours. Integrated sampling provisions are also retained.

54. Section 506.1 changes are made to clarify that all monitoring equipment (see added definition for “flare monitoring system”) come under this section. Flare monitoring will require a significant amount of equipment. Since much of this monitoring will be new installations and will involve monitoring that has not typically been done in this application, it is likely that there will be more instrument downtime than an old, existing monitoring requirement. Therefore, we recommend that the wording in this section be made consistent with the continuous emission monitoring requirements found in Regulation 1-522.4. To accomplish this, the last sentence in 12-11-506.1 should be deleted. <Buchan, WSPA. 4/17/03>

Rather than eliminate the sentence that limits downtime to 30 days in a calendar year, staff is recommending changes to the proposed rule to allow a 6-month delay in this requirement for integrated sampling, gas chromatography, and other continuous analyzers to allow time to identify and correct problems in the systems before the requirements come into effect.

55. Section 506.2 requires manual sampling during periods of inoperation of continuous analyzers. This should extend to auto-samplers. We believe this was the District’s intent. <Buchan, WSPA. 4/17/03>

This was our intent, but the change was not included in the proposed rule. The revised rule includes this change.

56. Section 506.4 changes clarify that many in-line analyzers cannot provide one-minute averages since the analytical sampling period is greater than once per minute. For example, most if not all hydrogen sulfide analyzers have a response time of 3 minutes or longer. Gas chromatography analyzers take 30 minutes or more for a complete analysis. Therefore,
since many analyzers are incapable of providing one minute data, let alone averages, that portion of the section should be removed. <Buchan, WSPA. 4/17/03>

The section indicates that the data logger must be capable of recording one-minute averages. The District recognizes that composition data will not be one minute averages and need not be recorded as such.

57. The requirement to archive video images for each 24-hour period should be changed to a requirement to archive the images for each day to clarify daily archiving of daily video monitoring. <Buchan, WSPA. 4/17/03>

The proposed language change would not change the requirement. The “24-hour” language was used to allow flexibility to produce a daily archive that runs from, for example 12 noon to 12 noon, rather than limiting it to a 12 am to 12 am day.

58. EPA commonly allows an Equivalent Voluntary Consensus Standards Body to determine the most appropriate methods for analyses. Examples of this are ASTM, API and others. In this way, the rule need not be opened each time a more accurate, sensitive, or appropriate method is deemed more suitable for the analysis. <Buchan, WSPA. 4/17/03>

The text of the proposed rule, in Section 12-11-601, did not address this issue. The revised rule addresses the issue, and allows subsequent revisions to methods to be used.

59. Initial Studies with proposed Negative Declarations or Mitigated Negative Declarations require at least 20 days for public comment (30 days if submitted to the State Clearinghouse). See California’s Environmental Quality Act (CEQA) Guidelines, Sec. 15073(a). The BAAQMD published its Request for Comments online on April 7, 2003. Since comments are due today, April 17, 2003, the District has provided merely 10 days for public comment. Accordingly, OCE request that the District provide an explanation for the abbreviated comment period. <Costa, Our Children’s Earth Foundation (OCE). E-mail. 4/17/03>

The document on which comments were requested was a draft initial study. No public review of a draft initial study is required by CEQA. Initial studies typically serve as the basis for an agency’s conclusion about the appropriate CEQA document required for a project. If an agency decides that a negative declaration is the appropriate document, it must, at that point, indicate that it intends to adopt a negative declaration (which includes the initial study) and provide for the review period required by CEQA Guidelines section 15073. The District has now made the negative declaration for this rule development project available for a review period exceeding 20 days. In asking for any comments on the draft initial study,
the District was providing an opportunity for comment beyond those required by CEQA.

60. The BAAQMD’s flare monitoring rule should require that the District take stack samples during flaring incidences, in normal weather conditions, to determine the amount of chemicals released into the atmosphere. <Costa, OCE. 4/17/03>

Refinery and District safety requirements preclude sampling in the flare combustion zone. Remote sensing can be used to study combustion emissions. The District is following such a study being conducted under contract to the Texas Commission on Environmental Quality (TCEQ).

61. The flare monitoring rule should require that the BAAQMD include all the emissions reported pursuant to the proposed rule in the emissions inventory to assess whether the Bay Area is making Reasonable Further Progress in the direction of compliance with NAAQS <Costa, OCE. 4/17/03>

The BAAQMD emissions inventory already includes flare emissions of 13 tons per day based on data from an earlier BAAQMD flare study (see the discussion regarding inventory issues in the Bay Area 2001 Ozone Attainment Plan on pp. 6-7). Although the District's preliminary estimate in the current flare study was higher than 13 tons, the estimate was based in part on assumptions that will need to be revised to reflect data received after the estimate was made. Although the current study has not been finalized, emissions estimates will likely be lower than indicated in the draft study, and may be no higher for the study period than the 13 tons already included in the inventory. Data gathered through monitoring installed pursuant to the monitoring rule should provide a basis for estimating flare emissions that is far superior to the bases underlying previous estimates, and can be used to refine the inventory.

62. The 98-99% destruction efficiency rate assumes that certain meteorological conditions are also being met. EPA studies conducted in the early 1980’s do not take into account environmental factors that may affect flare efficiency. “There is no suggestion [in the EPA study] that combustion efficiencies may depend on parameters that influence flame size, and consequently heat releases, such as stack velocities and wind speeds.” [Douglas M. Leahey, Katherine Preston and Mel Strosher, Theoretical and Observational Assessment of Flare Efficiency, 51 J. Air & Waste Mgmt. 1610, 1616 (2001).] More studies should be done to determine the correct destruction efficiency rate. <Costa, OCE. 4/17/03>

Most arguments about flare efficiency that have been made to the District are based on a selective reading of technical scientific and technical literature on the subject, and much of that literature is not analytically robust. The Technical Committee of the BAAQMD Advisory Council is currently exploring the question
of efficiency. In addition, an interesting flare efficiency study is currently being conducted by the Texas Commission on Environmental Quality (TCEQ). The study is expected to be completed in 2003, and the District will follow this effort and other relevant studies closely. The District agrees that a better understanding of flare efficiency is desirable, and expects that studies currently underway will promote a better understanding.

63. Bay Area residents deserve to know about the pollution released in their own backyard; the BAAQMD should publish the flare monitoring reports online. <Costa, OCE. 4/17/03>

See response #10.

64. The flare monitoring rule should ensure that the monitoring data will disclose the amount of pollution that is actually released and ensure that the information is transparent so that Bay Area residents can interpret the data. <Costa, OCE. 4/17/03>

This is the intent of the flare monitoring rule.

65. BAAQMD should conduct further investigations to ensure that flare technology is satisfactorily destroying pollutants emitted through waste streams at these facilities in the Bay Area and to take an active role in requiring facilities to reduce the level of emissions produced through upsets, startup, shutdown, and maintenance events. <Costa, OCE. 4/17/03>

The District is following the TCEQ study on flare efficiency and other studies on flare efficiency. The flare monitoring rule requires monitoring but does not impose controls. See responses #13, #17, and #21.

66. Reports of smoke are entirely dependent on visual observations made by workers at these facilities who may miss many events. BAAQMD must require accurate reporting of emission discharges from flare operating systems and improved reporting requirements so as to better distinguish between reporting of smoking flare events and opacity events which are not related to flares. <Costa, OCE. 4/17/03>

Enforcement of smoking and opacity restrictions requires visual observation, and reporting is insufficient for enforcement purposes. Opacity monitoring required by 40 CFR §60.18 is based on Method 22, a visual observation method. The District uses visual observation methods to enforce a three-minute-per-hour smoke limit on all flares, whether they are subject to the NSPS or not.

67. Reports of VOCs, H2S, and other emissions should be based on much more accurate estimates of flare performance that take into account factors which diminish combustion efficiency. <Costa, OCE. 4/17/03>
See response #62.

68. Sources are required under state and federal law to ensure that flares will not smoke for more than five minutes in a consecutive two hour period. Yet, many sources report repeated violations of flares which smoke beyond five minutes in their upset reports. BAAQMD must enforce violations of the smoking flare requirements and ensure that sources are abiding by state and federal law. <Costa, OCE. 4/17/03>

This statement is a direct quotation from a report by a New York environmental group on smoking flares in Port Arthur, Texas. It is not correct as a statement of California conditions or law. The BAAQMD enforces California and BAAQMD requirements that are more stringent than the cited standards.

69. Recent studies indicate that flare combustion technology is not performing at expected levels of efficiency when conditions such as high wind speed are present. BAAQMD must require companies to improve current technology and enhance flare design to rectify the affects of meteorological conditions on flare combustion. <Costa, OCE. 4/17/03>

This is also a direct quote from the Port Arthur, Texas report. See response #68. Regarding efficiency, see response #62.

70. Notes need to be taken at ALL meetings- whether they are community meetings, public workshops, public hearings or work group meetings. <Cosentino, Communities for a Better Environment (CBE). E-mail. 4/17/03>

The District generally makes sound recordings of workshops but did not do so for the community meetings on the flare monitoring rule. It is important to note that the meetings were conducted in addition to, not in lieu of, an opportunity to submit comment.

71. Notes from community and industry meetings need to be posted on the District’s website and distributed to all participants. Transparency in the rule making process is of benefit to everyone involved. <Cosentino, CBE. 4/17/03>

The District regularly meets with community members and with the industries it regulates. Many of these meetings are informal, and notes are not taken. District resources available to record these informal discussions are limited. At some point, commitment of resources to transcription of discussions takes away from the District’s ability to conduct outreach and solicit views.

72. Facilitation needs to be improved. The District should have both a facilitator and a “stacker” (to keep track of who raises their hand first and call on people) at all meetings. Also the stacker should help bring around a
microphone which would ensure everyone can hear the public’s questions and comments as well as the Districts (the microphone would also record people’s comments). Everyone should be allowed to speak, and open discussion about issues should be encouraged. <Cosentino, CBE. 4/17/03>

Comment noted. These appear to be reasonable suggestions for conducting some formal meetings.

73. Develop a follow up plan with the community. The District does not need to answer everyone’s questions in the meeting, but should develop a follow-up plan with the community as to how issues will be addressed by the District. <Cosentino, CBE. 4/17/03>

Comment noted. This also appears to be reasonable for certain processes.

74. An agenda needs to be provided ahead of time and should be posted and followed in the meeting. I understand the District intended to move quickly to adopt a flare monitoring rule. However, this should not be at the expense of a meaningful public process. I remind you that a false process such as this violates Environmental Justice Principles. Environmental Justice Principle #7 Environmental Justice demands the right to participate as equal partners at every level of decision-making, including needs assessment, planning, implementation, enforcement and evaluation. <Cosentino, CBE. 4/17/03>

The District disagrees with the view that the process for developing this proposed rule was somehow a "false process." The meetings that were conducted provided a forum for discussion of a great many issues and concerns, and many members of the communities thanked us for the effort. We have also provided extensive opportunity for comment since the meetings. The District acknowledges that more productive feedback and discussion could have occurred if there were more time to complete the process. As you know, the 2001 Ozone Plan as approved by the three regional agencies allowed to the end of 2003 to complete the further study measures. At the request of CBE and others, the District agreed to complete drafts of the further studies by the end of 2002. This has left us with fewer resources to devote to the control measures in the Plan.

75. I believe it would be of great benefit to the District in administering this rule, if the requirement was added for submittal of a Flare Monitoring Plan from each affected refinery. The required plan would include:
   Description of all flare monitoring and video monitoring equipment proposed for compliance with the rule;
   Detailed description of manufacturer’s specifications, including type, manufacturer, model, range, precision, accuracy, calibration and maintenance requirements, and recommended quality assurance
procedures;
Description of proposed sampling locations for each flare at the facility;
Description of proposed type of gas composition sampling and analytical methods to be used for each flare at the facility;
Description of selected flow verification test methods to be used;
Description of data collection and management systems;
Proposal for alternative sampling methods/protocols.
I think that adding this level of structure to the new rule would benefit both the refineries and the District in overall execution of the new rule, especially considering individual system modifications over time. Wileen Sweet-Dodge, Environmental Manager, Emerald Hills, CA. E-mail. 4/17/03.

The District considered this approach. The South Coast AQMD rule requires submission of monitoring plans that include these elements. However, incorporating a process for plan submission, review, and approval would substantially delay effectiveness of the rule. District staff ultimately decided that requirements for flare monitoring could be adequately put into effect and enforced through generic rule provisions. The District believes the proposed rule, in conjunction with other information-gathering tools, will allow it to obtain necessary facility-specific information, and to track changes that occur over time.

76. Once a day gas composition sampling allowed by the rule completely invalidates its usefulness, and legally allows 11 or more tons per day of unmonitored hydrocarbon emissions, resulting in little or no progress toward monitoring and determining Bay Area flare emissions. <May, Communities for a Better Environment (CBE). E-mail. 4/17/03>

This comment was based on the sampling trigger proposed in an earlier draft. The trigger level has since been modified and made more stringent relative to that earlier draft. Even with the trigger level in the earlier draft, all flows would be monitored for volume, and so it was not the case that 11 tons of emissions would go unmonitored. See response #1.

77. Sampling should be required every 15 minutes rather than once per day. <May, CBE. 4/17/03>

The current proposal allows four different approaches to sampling. Three of the four methods require sampling every 15 minutes or continuously. Manual sampling, which is also allowed, is likely to be used for flares that are used infrequently. Manual sampling would not be practical for flares used regularly because it would become cumbersome with regular use and would involve unnecessary risks to workers. Even this manual sampling method is more stringent than the South Coast AQMD rule.

78. Readily available and cheap autosampling should be required to protect workers from hazards and to facilitate more frequent sampling. <May, CBE. 4/17/03>
Autosampling is one of the methods allowed in the rule. The rule continues to allow manual sampling because some flares have not been used in years, and imposing a requirement to install auto-samplers or continuous analyzers for these flares would not be reasonable. See response #77. All equipment, whether manual sampling equipment, auto samplers, or continuous analyzers require attention and maintenance and therefore some risk to workers.

79. Available flow monitoring equipment has the capability to detect flows ten times lower than the 50,000 cu ft/hour threshold, making unnecessary the exemptions for lower flows where efficiency may be lower. <May, CBE. 4/17/03>

No version of the rule has included such an exemption. See response #2.

80. The lax “flow verification” section (12-11-602) allows the choice between vague and undefined methods for quality control of flow measuring equipment and should be narrowed and defined. <May, CBE. 4/17/03>

Section 12-11-602 has been revised to delete less well defined verification methods. Also see response #3.

81. The flare efficiency is defined as 98% in the regulation, which does not account for conditions known to cause efficiency to go far below this number. <May, CBE. 4/17/03>

Most arguments about flare efficiency that have been made to the District are based on selective readings of scientific and technical literature, and much of that literature is not analytically robust. The District expects that progress will be made in the near future towards understanding flare efficiency. For instance, the Technical Committee of the BAAQMD Advisory Council is currently exploring the question of efficiency. In addition, an interesting flare efficiency study is currently being conducted by the Texas Commission on Environmental Quality (TCEQ). The study is expected to be completed in 2003.

The proposed rule did not require calculation of emissions by flare operators, and the specification in earlier drafts of the efficiency to be used was deleted. At the request of WSPA and the Unions at the May 8th flare workgroup meeting, the revised rule re-incorporates a requirement for emission calculations. The Unions suggested using the efficiencies specified in the Texas rule (98% for most flares, 93% for low-BTU gases). While WSPA has argued for higher efficiency, the proposed rule includes the Unions’ suggestion.

The reasoning behind specifying an efficiency figure, as articulated by the Unions and WSPA, seems to be that it is better to provide the public with some estimate of total emissions, even if the estimate employs some assumptions that are open to debate. District staff was persuaded by this reasoning, and so has incorporated assumed efficiencies in the revised rule. However, it is important to
note that these efficiencies are set for the narrow purpose of emissions estimates to be made in reports submitted by refineries pursuant to the rule. The proposed rule does not restrict the District or anyone else from using a different efficiency figure in any other context. If the District does use a different efficiency figure, it will of course explain its reasoning for doing so. If more reliable information regarding flare efficiency becomes available, the District will consider revising the rule to reflect that information.

82. The District should explore and report on available methods for determining flare efficiency and emissions in the atmosphere. <May, CBE. 4/17/03>

The Advisory Council Technical Committee is examining the question of flare efficiency. The District is also monitoring progress on the TCEQ study mentioned in response #62.

83. Putting video monitoring of flaring on the web would allow District staff to instantly view in real-time the same incidents neighbors are reporting, and allow them to discuss flaring with refinery personnel as events are occurring. <May, CBE. 4/17/03>

The proposed rule does not require web posting for the reasons discussed in the staff report (see discussion of Section 12-11-507). Video monitoring records must be submitted to the District each month.

84. Video monitoring records should also be electronically stored at the District. <May, CBE. 4/17/03>

See response #82.

85. The current version of the rule actually neglects to require that the refiners submit the video image archives to the District with the monthly report. <May, CBE. 4/17/03>

Section 12-11-401 has been revised to require submission to the District.

86. The rule unnecessarily limits the requirement for storage of video monitoring to one frame per second, effectively reducing the video monitoring to a bunch of snapshots that don’t show the full effect of flame characteristics. <May, CBE. 4/17/03>

The video frame rate of the proposal is intended to ensure that electronic video files are of reasonable size so that they can be easily stored and distributed. This requires a frame rate of one frame per minute, the frame rate found in the proposed rule. At higher frame rates, files cannot be sent electronically and would require multiple DVDs per month to store the images for each flare.
87. The recently added blanket exemptions for monitoring sulfur recovery plants and flexicoker gas ignore hydrocarbons present in these streams which can significantly add to flare emissions. <May, CBE. 4/17/03>

The exemption in the earlier draft rule was not a “blanket exemption;” the exemption only exempted these flares from composition monitoring for hydrocarbons. Monitoring for flow and sulfur content was required. The proposed rule entirely deleted this exemption. District staff is now recommending in the revised rule to add back a more limited exemption for flares burning gas from a flexicoker. For these flares, the operator would have to monitor for flow and sulfur content. The limited exemption would allow an operator to avoid monitoring for hydrocarbons provided methane concentration was demonstrated to be less than 2% and non-methane hydrocarbon content was demonstrated to be less than 1%.

88. Exemptions for monitoring flaring of operations of wastewater ponds, marine vessels, and storage tanks could represent huge emissions and should be removed. <May, CBE. 4/17/03>

These exemptions are limited to thermal oxidizers for which emissions can be measured directly and to several small flares that serve as backup to vapor recovery systems. The one flare that is neither a thermal oxidizer nor a safety backup flare is one that controls emissions from a railcar loading operation at the Shell refinery. The staff report now includes a more detailed discussion of the exemptions and the sources to which they would apply.

89. Equipment downtime less than 24 hours is exempt from reporting. <May, CBE. 4/17/03>

The proposed Section 12-11-401.7 requires reporting of downtime exceeding 24 hours. District staff are recommending in the revised rule to require that monthly reports include all downtime. This data for shorter downtime periods would generally be available in the monthly reports even without this explicit requirement because monitoring data from flow meters and continuous analyzers should be continuous data; all monitor downtime would then appear as data gaps. For CEMs, the refineries typically note data gaps due to meter downtime. Note that the rule requires calculation of flows if flow monitors are down, and sampling if continuous analyzers are down.

90. Both H2S and total sulfur need to be monitored (not total reduced sulfur which misses oxidized sulfur compounds-section 502.3 3.2). If only total sulfur is measured, then for purposes of compliance with federal Subpart J H2S limits, all of total sulfur must be considered as H2S. <May, CBE. 4/17/03>

Flare gas does not contain significant amounts of oxidized sulfur compounds. Monitoring of total reduced sulfur is appropriate for determining compliance with
the Subpart J limits, which apply to flares that were subject to New Source Review and are used as control devices.

91. Continuous monitoring is feasible, and monitoring “dirty” streams of fuel gas and sulfur recovery plants is common in Bay Area refineries. <May, CBE. 4/17/03>

Continuous analyzers are used at refineries to monitor sulfur compounds in fuel gas and after sulfur recovery. Fuel gas is quite clean compared to flare gas, and any monitoring at sulfur recovery plants using sensitive equipment is downstream of sulfur recovery and required tail gas control units. No refinery in California or Texas has used continuous analyzers on flare vent gas. The rule is structured to encourage this approach, but other methods must be allowed to ensure that the rule will be workable.

92. The public review process for this rulemaking had severe problems which can be avoided in the future. <May, CBE. 4/17/03>

At the direction of the APCO/Executive Officer, the staff put the development of this rule on a fast track. As the commenter is aware, the 2001 Ozone Plan as approved by the three regional agencies allowed to the end of 2003 to put into effect control measures anticipated in the Plan. At the request of CBE and others, the District agreed to complete drafts by the end of 2002. It was foreseeable and perhaps inevitable that we would have to expedite this rulemaking effort and that other control measures will be similarly expedited. The District has tried to balance the need for an expedited process, as driven by Plan deadlines, with the desire expressed by many for a more thorough and deliberate rule development process.

93. The rule proposed by the District would fail to detect up to 93% of flaring events, based on actual flaring data submitted by the Shell refinery, and would fail to detect up to 80% of flaring events at the ChevronTexaco refinery. Because of inadequate detection limits, the proposed rule would allow the flares to release over 28 million cubic feet per day of gases, or a total of 11 tons per day, without any monitoring. <Drury and Fox, Refinery Trade Unions - PSU Local 302, IBEW Local 549, Laborers Local 324, Insulators Local 16 (Unions). E-mail and messenger. 4/17/03>

None of this flow would be missed by flow meters. The comment is misleading in failing to state that the commenters are claiming that composition sampling would not be required for these flows because, in their opinion, the sampling trigger in the earlier draft was not sufficiently stringent (note that the revised rule includes the trigger level advocated by the Unions in their comments). The Shell and Chevron data is not “actual flaring data” and does not come from flow meters. It is based on calculations and estimates and therefore on average flows. Because averages would miss the variability that is found in actual flow meter measurements, the Shell and Chevron estimates provide no information that can
be used to determine whether sampling would have been required under any proposed trigger. It can be said, however, that most of the Shell flaring events were of such short duration that no sampling would have been possible, regardless of the sampling trigger used. It is also important to note that the Shell and Chevron estimates indicate that these two refineries were together responsible for about 9% of all vent gas flared during the study period (excluding Shell's flexi-gas flare for which sampling or continuous analysis would clearly be required under either the earlier or current trigger proposal).

94. The proposed rule is inadequate because it only requires once per day monitoring for most flaring events (Rule Section 502.3.3. 1.a) except when the flow to the flares exceeds 50,000 cubic feet in any 60 minute period. The Bay Area's rule should be at least as stringent as the rules in Texas, Utah and Los Angeles. The rule should require automatic sampling or continuous composition monitoring every 15 minutes after any flow is detected above 0.1 feet per second, and the sampling should continue every 15 minutes until the flaring ceases. <Drury and Fox, Unions. 4/17/03>

The composition monitoring trigger level in the revised rule is identical to that in the South Coast AQMD flare monitoring rule. However, the sampling frequency requirement is far more stringent than the South Coast rule because it requires samples every 15 minutes after the trigger level is reached if integrated sampling is used and every 3 hours if manual sampling is used. Note that manual sampling is not likely to be used if a flare is in regular use. See response #77. The South Coast rule only requires one sample per week once sampling is triggered.

The Texas rule applies to flares that receive gas streams containing at least 5% highly-reactive VOCs (defined as 1,3 butadiene, butenes, ethylene, and propylene – see Title 30, Texas Administrative Code §115.10). Refinery flare gas typically contains less than 5% of these highly-reactive VOCs. The Texas rule was written for chemical plant flares and is not an appropriate comparator.

The Utah rule applies to landfill gas collection systems and requires that flow rate (not composition) be monitored every 15 minutes "to identify periods when the gas flow has been diverted from the control device or periods of no flow from the collection system." The Utah rule therefore does not support the commenter’s assertion regarding frequency of composition monitoring. Regarding flow rate monitoring, the Utah rule is clearly less stringent than the proposed rule, which requires continuous monitoring of flow rate.

95. The detection limits required by the rule will fall to detect many flaring events, despite the fact that much more accurate technology is readily available. <Drury and Fox, Unions. 4/17/03>
The rule requires all flows to be measured and reported (see Section 12-11-401). The comment is based on a misinterpretation of Section 12-11-501, which specifies a series of requirements for any device used to measure flow. These requirements can, at present, be met only by ultrasonic flow meters. A major manufacturer guarantees these meters to be accurate to within 5% over the range from 1 to 275 feet per second. Specifying this flow velocity range does not mean that the meter does not measure lower flows; it just does so with reduced accuracy.

96. The proposed rule only requires monitoring of what goes into the flare, not what comes out and assumes that 98% of flare gas is destroyed. An estimated efficiency of 98% should only be allowed when the requirements of 40 CFR §60.18 are met. At all other times, an estimated efficiency of 80% should be used, which is the lowest reported efficiency in studies relied upon by the District for a large flare. The BAAQMD should conduct a flare destruction efficiency study to analyze actual efficiency in the field, and the results of that study may be used to refine the rule. <Drury and Fox, Unions. 4/17/03>

See response #81.

97. The exemptions for marine vessel loading, sulfur recovery plant flares, flexicoker flares, thermal oxidizers, and organic liquid storage should be removed from the rule. <Drury and Fox, Unions. 4/17/03>

The exemption for sulfur recovery plants and flexicoker flares was removed from the proposed rule. Staff is now recommending and has included in the revised rule a limited exemption for flexicoker flares. The staff report provides justifications for the other exemptions included in the rule. All of the exempted devices, except for flares exempted by Section 12-11-110, are thermal oxidizers, which, unlike flares, are enclosed combustion devices that exhaust combustion products through a duct or stack where they can be directly measured. The proposed rule requires monitoring of the gas input to flares because there is no readily-available means to directly measure flare emissions (though some remote sensing devices are being used in research). There is no useful purpose in imposing flare monitoring requirements on devices from which emissions can be directly measured. For a discussion of the flares exempted by Section 12-11-110, see response #99.

98. The staff report provides no justification for the distinction between flares and thermal oxidizers or the assumed de minimus [sic] emissions. <Drury and Fox, Unions. 4/17/03>

This comment was made on an earlier draft of the staff report. The staff report discussion of this issue has been expanded. As noted in response #92, thermal oxidizers and flares are different devices. The thermal oxidizer definition in the proposed rule (Section 12-11-209) clarifies this distinction. The Fox comments
are incorrect in claiming that “a thermal oxidizer is a flare.” The distinction drawn between the two in most air pollution control literature is the same as that drawn by the added language: a thermal oxidizer exhausts combustion products through a duct or stack where emissions can be directly measured. For that reason, it would serve no useful purpose to impose requirements to monitor gas going to a thermal oxidizer when the combustion products can be directly measured in the stack.

99. The exemption for organic liquid storage and distribution [in Section 12-11-110] is not justified because emissions are high enough to warrant concern. <Drury and Fox, Unions. 4/17/03>

The staff report states that this exemption would apply to six sources in the District: a backup safety flare for a propane tank at the Tesoro refinery, a similar flare for a butane sphere at the Valero refinery, three backup flares for vapor recovery systems on tanks at the Shell refinery, and a flare for the LPG railcar loading operation at the Shell refinery. All but the LPG loading flare are secondary control devices that are used when a vapor recovery system fails or is being maintained. The Fox comments claim that “the emissions from the Shell tank flares were 1.2 tons per year of VOCs and 0.1 ton/yr of SO2” as the basis for an argument that the flares should not be exempt from the rule. The VOC emissions are 6.6 pounds per day. From the perspective of the proposed rule, these emissions are de minimis and do not warrant the kind of monitoring that the rule requires for flares, which can potentially emit VOCs at a rate three or four orders of magnitude higher. In addition, all of these sources are control devices used to comply with other District regulations.

100. The exemption for flares and thermal oxidizers used to control marine vessel loading should be eliminated because there is no data to confirm that they have negligible emissions. <Drury and Fox, Unions. 4/17/03>

Thermal oxidizers are used at the Chevron, ConocoPhillips, and Shell refineries to meet Regulation 8, Rule 44 control requirements. No marine loading terminal uses a flare for control. The thermal oxidizers at the three marine terminals have high efficiencies that are mandated by the rule and by permit conditions and can be directly verified by source tests. Because these devices are, by definition, thermal oxidizers, they are not subject to the rule. This exemption is therefore included merely to clarify their exempt status. In any case, it would serve no useful purpose to impose the flare monitoring rule requirements on these devices because emissions can be directly determined through a source test of the thermal oxidizer stack.

101. The exemption for thermal oxidizers used to control emissions from wastewater treatment systems should be eliminated because emissions from wastewater systems are significant. <Drury and Fox, Unions. 4/17/03>
The Fox comment suggests that because wastewater treatment systems as a category may have significant emissions, thermal oxidizers that control wastewater sources should be subject to the flare monitoring rule. But emissions from thermal oxidizers are directly verifiable; imposing requirements to monitor gas flow to an oxidizer would be unnecessary. In any case, these devices are exempt by definition. See responses #98 and #100.

102. Sulfur recovery plant flares should not be exempt because of the potential for organic emissions. <Drury and Fox, Unions. 4/17/03>

This exemption has been dropped.

103. Flexicoker flares should not be exempt from monitoring for hydrocarbon and methane composition because flexicoker gases may contain elevated concentrations of methane and other hydrocarbons. <Drury and Fox, Unions. 4/17/03>

This exemption was dropped from the proposed rule. Staff are recommending and have included in the revised rule a limited exemption from hydrocarbon and methane monitoring (Section 12-11-114). The exemption is conditioned upon a weekly lab analysis showing that methane and non-methane hydrocarbons are not found in elevated concentrations (methane content must be less than 2% and non-methane hydrocarbon content must be less than 1%).

104. The definitions of flare and thermal oxidizer are inadequate. <Drury and Fox, Unions. 4/17/03>

These definitions have been clarified. Language in the definition of thermal oxidizer makes it clear that a thermal oxidizer exhausts combustion products through a vent, duct, or stack that allows direct measurement of combustion products. See response #98.

105. The vent gas definitions should not exclude purge and pilot gases because only vent gas is monitored for composition, and these gases may contain hydrocarbons. <Drury and Fox, Unions. 4/17/03>

Most of the flares at refineries in the District use water seals and do not use purge gas at all. For those that do, natural gas is used. Requiring composition monitoring would be pointless. If there were a reason to require this monitoring, changing the definition of vent gas would not be the appropriate way to accomplish this purpose.

106. The rule should be modified to require posting of monthly reports on the District website within 24 hours, placing copies in libraries, and preparation and distribution of CDs containing all supporting data. <Drury and Fox, Unions. 4/17/03>

The District will consider use of the District website. See response #10.
107. The reporting requirements allow emission calculations to assume a flare control efficiency of 98%. The studies do not support this assumption, and we recommend that the section be amended to adopt the TNRCC approach. <Drury and Fox, Unions. 4/17/03>

See response #81.

108. The language in Section 12-11-501.2 should be modified to read: “The device shall continuously measure velocity over the full potential range of operation of each covered flare, from a minimum velocity of 0.1 ft/sec to the maximum expected for each individual flare, but no lower than 275 ft/sec. <Drury and Fox, Unions. 4/17/03>

This comment reflects a concern that the specification (in Section 12-11-501.2) that the flow measurement device measures the velocity range from 0.5 to 275 feet per second is a limitation on the requirement in Section 12-11-401 to report all flows. Section 12-11-501 is intended as a device specification that effectively dictates ultrasonic meters. The velocity specification does not mean that the meter is incapable of measuring lower flows; it just does so with reduced accuracy.

109. We recommend that the rule be revised to require a minimum accuracy of 5% over the entire flow range. <Drury and Fox, Unions. 4/17/03>

The proposed rule did not include an accuracy specification for the flow monitoring device. The revised rule now includes an accuracy specification in Section 12-11-501.

110. Section 501.4 should be modified to require that the monitor be located 'on the main flare header, after the knock-out pot and addition of any supplementary fuel' to assure that it measures the flow that is actually combusted. <Drury and Fox, Unions. 4/17/03>

The suggested language is too prescriptive and, in some cases, would dictate the installation of a flow meter within the radiation zone of a flare. The heat would destroy the meter.

111. We recommend that Section 501.3 be modified to require molecular weight, temperature, and pressure to be continuously measured. <Drury and Fox, Unions. 4/17/03>

Time of flight ultrasonic meters automatically make these measurements in order to produce volumetric flow outputs in standard cubic feet. Including these requirements in the device specification would preclude competing technologies that might offer superior performance without relying on these measurements. The proposed rule adds a requirement that molecular weight data be reported if available from the flow meter (Section 12-11-401).
112. We recommend that Section 501.3 be modified to require that the monitors be maintained according to vendor specifications and annually calibrated to specifications. <Drury and Fox, Unions. 4/17/03>

All drafts of the rule have included a requirement (in Section 12-11-506.3) that meters be maintained and calibrated in accordance with the manufacturer’s specifications.

113. Because of worker safety issues, we suggest that the rule state that manual sampling may not be used. <Drury and Fox, Unions. 4/17/03>

The proposed rule does not include a provision for manual sampling. However, District staff have concluded that manual sampling is an appropriate option for flares that are used infrequently. For these flares, which may combust vent gas less than once per year, installation of auto-samplers or continuous analyzers would be unreasonable. In addition, the maintenance necessary to keep this equipment in a state of readiness would involve greater worker exposure to risk than would an occasional need to sample manually. The revised rule therefore includes a manual sampling option. This option uses the stringent South Coast AQMD trigger for sampling.

This manual sampling option would probably not be practical for flares that are used with some regularity. The need to continually take samples would be burdensome, and would likely result in missed samples. Because of these considerations, the District expects that the use of manual sampling will be restricted to low usage flares.

114. The draft rule’s trigger of 50,000 standard cubic feet in an hour with samples required within 15 minutes for auto-samplers and 30 minutes for manual sampling and with subsequent samples every three hours thereafter means that samples are taken at flows that are too high, too long after flaring starts, and too infrequently thereafter. The rule should be modified to require that sampling commence within 15 minutes of the detection of flow and to reduce the sampling frequency to every 15 minutes. <Drury and Fox, Unions. 4/17/03>

At the flare workgroup meeting on April 18th, significant time was spent discussing the trigger level for composition sampling. Based on these discussions, the proposed rule specified a composition sampling trigger level of 6,000 standard cubic feet in 15 minutes, which represented a flow velocity of approximately 0.5 feet per second, the lowest velocity that District staff felt would represent real flows to the flare (see response #1). At the May 8th workgroup meeting, refinery representatives suggested that the trigger was too sensitive, and the Unions proposed use of the South Coast AQMD trigger. The revised rule incorporates the South Coast sampling trigger, with sampling to begin within 15 minutes. Sampling would then be required every 3 hours with the manual sampling option, every 15 minutes with integrated sampling, and continuously
with continuous analyzers. These requirements for sampling frequency are far more stringent than the South Coast AQMD requirements (which specify one sample after the trigger is reached and a weekly sample thereafter).

115. Section 12-1-502 should be revised to require that both total sulfur and H₂S be measured because oxidized sulfur compounds are included in vent gas streams. <Drury and Fox, Unions. 4/17/03>

Oxidized sulfur would not typically be found in flare vent gas in significant quantities.

116. Section 502 should be modified to require that opacity and net heat content be monitored using the methods in 40 CFR 60.18 to ensure that the control efficiency is met. <Drury and Fox, Unions. 4/17/03>

Opacity monitoring required by 40 CFR §60.18 is based on Method 22, a visual observation method. The District already uses visual observation methods to enforce a three-minute-per-hour limit on all flares, whether they are subject to the NSPS or not. The District standard is more stringent than the NSPS standard. Sampling, integrated sampling, and GC analysis already specified in the rule would provide composition data that would allow the heat content to be calculated.

117. We recommend that Regulation 12, Rule 11 be expanded to require that each refinery use an optical, remote-sensing instrument capable of measuring both S02 and hydrocarbons in flare exhaust gases. <Drury and Fox, Unions. 4/17/03>

Optical remote sensing equipment is currently used in flare efficiency research. This equipment is large, complicated, extremely costly, and requires highly-trained operators. Open-path passive FTIR systems rely on radiation differences between hot flare combustion gases and background and have higher limits of detection than active FTIR systems which use a radiation source. FTIR measurements depend upon keeping the plume within the instrument’s field of detection. Passive FTIR is not suitable for flare monitoring because the flare plume varies in size and shape with flaring rate and moves with wind. Flare studies require skilled operators to ensure that the plume remains within the instrument’s window.

118. We recommend that Section 506.1 be modified to require recordkeeping of all periods of monitor inoperation and monthly reporting of the accumulated downtime for each monitor. <Drury and Fox, Unions. 4/17/03>

District staff are recommending in Section 12-11-401.7 of the revised rule that all periods of monitor inoperation be reported.
119. We recommend that Section 506.2 be modified to require that any facility electing to use a continuous analyzer must also obtain equipment to allow manual or auto-sampling when the continuous analyzer is down and use it to collect a minimum of one sample every three hours. <Drury and Fox, Unions. 4/17/03>

In the revised rule, the sampling interval for manual sampling is three hours (see Section 12-11-502.3. When a continuous analyzer is down, this would be the default sampling interval.

120. A new section should be added to Section 506 that requires that flow rate be estimated when the flow meter is out of service using either the methods in Section 602 and/or flame length as recorded by the video. <Drury and Fox, Unions. 4/17/03>

This section in the revised rule now requires that flow be estimated using good engineering practices, which would allow use of the methods in Section 602, a flame length method, or other methods as available.

121. We recommend that Section 506.3 be modified to require annual maintenance and field zeroing of ultrasonic velocity meters. <Drury and Fox, Unions. 4/17/03>

All drafts of the rule have included a requirement (in Section 12-11-506.3) that meters be maintained and calibrated in accordance with the manufacturer’s specifications.

Written Comments Received in Connection with May 21st Hearing

The public hearing notice for the May 21st hearing on the revised rule indicated that comments would be accepted during the period from April 21st to May 12th. No comments were received during that period, but the following comments were received just prior to the May 21st hearing.

122. Section 401.7 waives reporting requirements during monitoring system breakdowns less than 24 hours. BAAQMD should consider revising this section to assure that the 24-hour reporting exemption due to monitoring system breakdowns is reduced or eliminated. <EPA. E-mail. 5/20/03>

EPA examined the proposed rule. The revised rule requires reporting of all monitor downtime.

123. Section 506 waives monitoring requirements during breakdown conditions. BAAQMD should consider revising this section consistent with more stringent requirements in South Coast Rule 1118 and to assure that breakdown exemptions are as short as possible. <EPA. 5/20/03>

Section 12-11-506 does not waive monitoring requirements during breakdown. Unlike the South Coast rule, Section 12-11-506 would require alternative
monitoring during periods of monitor inoperation. In addition, the composition monitoring required during downtime of automated composition analyzers is more stringent than any composition monitoring required by the South Coast rule.

124. ASTM Method UOP 539-97, referenced in Section 601, has not been reviewed by EPA for use in SIP-approved rules. BAAQMD should submit this method for EPA review. <EPA. 5/20/03>

The proposed rule specifies ASTM Method UOP 539-97 as one of three methods that may be used for the required analysis of vent gas samples. UOP 539-97 is the only ASTM method developed specifically for the analysis of the composition of refinery fuel gas, which may include up to 25% hydrogen sulfide. The proposed rule is a monitoring rule only, and as such, does not include any emission limitations. ASTM Method UOP 539-97, if used, would not be used to determine compliance. Therefore the District does not believe that it must be submitted to EPA for review.

125. Section 602, Flow Verification Test Methods, provides broad discretion for establishing methods to verify vent gas flow. Since this parameter is so critical to the rule, paragraphs 602.3, 602.4 and 602.5 should be revised to provide greater specificity on the verification methods that may be used. We are also concerned that the limit of detection for the methods in paragraphs 602.1 and 602.2 (4-6 feet per second) is not sensitive enough given the requirement in paragraph 501.1(0.1 feet per second). <EPA. 5/20/03>

Section 12-11-506.3 requires ultrasonic flow meters to be maintained and calibrated in accordance with manufacturer’s specifications. Properly maintained and calibrated ultrasonic flow meters are extremely accurate. No test method has been developed to test these meters in place once they have been calibrated and installed. To get a rough check on accuracy requires the use of existing less-accurate approaches such as pitot tube traverses, tracer gas methods, or other flow or process meters. The meters are more accurate than any of these alternative approaches. No other flare monitoring rule even includes provisions that attempt to make this check (see South Coast Rule 1118). The BAAQMD provision was developed to provide a means to identify large errors that might result from misinterpretation of the meter’s specified range and calibration factor. The District is proposing to revisit the rule in 18 months, review the data developed from the use of various alternatives, and make any appropriate changes in these provisions.

126. Section 502.3.1: The last sentence in Section 502.3.1.a states “In no case shall a sample be required more frequently than once every 3 hours.” We do not believe it is appropriate to relieve a facility from the requirement to initiate sampling within 15 minutes of exceeding the flow rate threshold specified if one “threshold event” is followed by another within two hours of the final sample taken during the initial event. It is unclear why this
change was made or how it would be implemented. We recommend the following modification: “In no case shall a sample be required more frequently than once every 3 hours during periods of flaring that continuously exceed the sampling threshold.” <ARB. E-mail. 5/20/02>

The District proposal is far more stringent than South Coast sampling provisions (which require one sample near the beginning of a flaring event and once per day thereafter during the event). The District provisions are intended to ensure that sampling is not required more frequently than is reasonably necessary for adequate data while ensuring feasibility and personnel safety. The District believes the proposed sampling requirements will provide the data necessary to adequately characterize the flare activity.

127. Section 506.1: We do not believe it appropriate to provide for “periods of inoperation” for purely manual sampling operations as proposed in Section 506.1. We recommend the following change: “Periods of inoperation of the vent gas auto-samplers installed pursuant to composition monitoring specified in Section 12-11-502.3.1 (grab sampling) shall not exceed 30 days per calendar year.” <ARB. 5/20/02>

The District agrees that downtime for purely manual sampling is not appropriate. This section has been changed.

128. Section 506.1: This section states: “Effective 450 days after the adoption of this rule, periods of inoperation of the vent gas composition monitoring specified in Section 12-11-503.3.3 (continuous analyzers) shall not exceed 30 days per calendar year per analyzer.” We believe the appropriate reference section is “Section 12-11-5032.3.3”. <ARB. 5/20/02>

The District agrees. This section has been changed.

129. Section 506.2: During periods of inoperation of continuous analyzers or auto-samplers installed pursuant to Section 12-11-502.3, we believe persons responsible for monitoring should be required to take samples as specified in Section 12-11-502.2. We recommend the following changes in the sections referenced in 506.2: “During periods of inoperation of continuous analyzers or auto-samplers installed pursuant to Section 12-11-502.3, persons responsible for monitoring shall take manual samples as required by Section 12-11-502.32.1.” <ARB. 5/20/02>

The District believes the sampling provisions for downtime are adequate to provide data necessary to characterize flaring during these periods. Staff reviewed its database for existing monitors in sulfur plants and fuel gas service (a service that is most similar to flare gas service) that were reported out of service pursuant to the CEM downtime provisions. These periods were infrequent, and it is anticipated that this will be the case for flare monitoring.
130. Section 507: We believe the one frame per minute video recording specification in Section 507 should be increased such that the recorded image is more representative of a real time recording and that each facility be required to archive their captured video data on a hard drive, and make specific portions of the archived data available to the district upon request. Due to the ability of current technology to store large volumes of digital data on one large hard drive (80 gig), we believe this approach will enable capture rates in excess of one frame per minute while still providing for a reasonable archive retention time (at least two weeks, possibly one month). <ARB. 5/20/02>

The District is now proposing to refer the issue of webcasting to the Stationary Source Committee of the Board. To avoid imposing video recording and storage requirements that would require immediate decisions about technology that might prove to be inconsistent with later recommendations of the Stationary Source Committee, the District is proposing to push back the effective date of this provision to allow further study of webcasting and related issues. Section 12-11-507 has been modified to be effective 180 days after rule adoption rather than 90 days to allow the necessary time for this effort.

131. Section 602: Due to the flexibility provided in the flow verification requirements of Section 602, we recommend each facility be required to submit a proposed flow verification plan that must be approved by the district prior to its implementation. <ARB. 5/20/02>

The District considered this option in the early stages of the workgroup meetings. South Coast Rule 1118 includes plan submittal requirements for flare monitoring. (Note that the South Coast rule has no flow verification requirements like those to which this comment refers.) The District believes that including plan submittal requirements for flow verification would add unnecessary delay in implementing the flow and composition monitoring requirements of the rule. The District is proposing to revisit the rule in 18 months, review the data developed from the use of various verification methods, and propose any necessary changes to these provisions.

132. The BAAQMD should adopt the Texas Rule under which an estimated efficiency of 98% should be allowed only when the requirements of 40 CFR §60.18 are met. At all other times, an estimated efficiency of 93% should be used. <Drury, Refinery Trade Unions - PSU Local 302, IBEW Local 549, Laborers Local 324, Insulators Local 16 (Unions). E-mail. 5/20/03>

The Texas rule does not apply to refinery flares (see response #94). District staff contacted TCEQ and confirmed this point. Nevertheless, the revised rule incorporated the concept of specifying an efficiency of 98% except for low-BTU gas. In the revised rule, 98% was specified except for the flexicoker flare, for which 93% was the default value. This flare handles flexicoker gas that has a low heating value. Staff are now proposing a change that requires the use of
93% for any vent gas with a lower heating value less than 300 British Thermal Units/Standard Cubic Feet (BTU/SCF) and therefore would not meet the requirements of 40 CFR §60.18. This is a minor change because data gathered during the flare study shows that most flare gas, with the exception of flexicoker gas, exceeds this BTU threshold.

133. The BAAQMD should conduct a flare destruction efficiency study to analyze actual efficiency in the field, and the results of that study may be used to refine the rule. <Drury, Unions. 5/20/03>

See responses #81 and #96.

134. Webcasting: The rule would be greatly improved by requiring “webcasting” of flare video-monitoring. Webcasting would allow any interested member of the public, including Air District staff and Board members, to see what is happening with refinery flares in “real time” simply by clicking on a page on the BAAQMD’s website. Air District staff could verify public complaints of refinery flaring instantly simply by clicking on the website. Webcasting is a low-cost and widely available technology. <Drury, Unions. 5/20/03>

To discuss webcasting and other issues, the District convened a meeting of the flare workgroup immediately following the May 21, 2003 Board meeting. Representative from WSPA, the individual refineries, refinery labor unions, and CBE attended this meeting. The consensus of all present was that the webcasting issue should be separated from the proposed rule and that the proposed rule should be adopted and implemented. District staff is recommending that the webcasting issue be referred to the Board’s Stationary Source Committee.

135. As you are well aware, the rate of asthma has climbed dramatically in the past decade, and ozone has been documented to have a direct connection. Of course, we are also concerned about particulate matter in release of emissions, as well as other chemicals. We agree that the videotaped footage of flaring required by the rule be placed on the web so that BAAQMD can view the same images that the public is seeing. And we also ask that the rulemaking begin soon to control flare emissions, not simply to monitor. <Weiner, American Lung Association of San Francisco and San Mateo Counties (ALA). E-mail. 5/20/03>

Ozone exposure in the Bay Area has declined at the same times that asthma rates have increased. The weight of the evidence suggests that ozone is not responsible for increases in Bay Area asthma rates. While it is true that high ozone levels can trigger asthma attacks, high levels are uncommon in the Bay Area.
Regarding webcasting, see response #134. The District’s flare workgroup is still working on the flare study that will determine the next steps regarding potential controls on flares. The District expects that if the study concludes that controls are available, the rule development effort to impose controls could be concluded by the end of 2003.
REGULATION 12
MISCELLANEOUS STANDARDS OF PERFORMANCE
RULE 12
FLARES AT PETROLEUM REFINERIES

INDEX

12-12-100 GENERAL
12-12-101 Description
12-12-110 Exemption, Organic Liquid Storage and Distribution
12-12-111 Exemption, Marine Vessel Loading Terminals
12-12-112 Exemption, Wastewater Treatment Plants
12-12-113 Exemption, Pumps

12-12-200 DEFINITIONS
12-12-201 Emergency
12-12-202 Feasible
12-12-203 Flare
12-12-204 Flare Minimization Plan (FMP)
12-12-205 Gas
12-12-206 Petroleum Refinery
12-12-207 Prevention Measure
12-12-208 Reportable Flaring Event
12-12-219 Responsible Manager
12-12-210 Shutdown
12-12-211 Startup
12-12-212 Thermal Oxidizer
12-12-213 Vent Gas

12-12-300 STANDARDS
12-12-301 Flare Minimization

12-12-400 ADMINISTRATIVE REQUIREMENTS
12-12-401 Flare Minimization Plan Requirements
12-12-402 Submission of Flare Minimization Plans
12-12-403 Review and Approval of Flare Minimization Plans
12-12-404 Update of Flare Minimization Plans
12-12-405 Notification of Flaring
12-12-406 Determination and Reporting of Cause
12-12-407 Deleted April 5, 2006
12-12-408 Designation of Confidential Information

12-12-500 MONITORING AND RECORDS
12-12-501 Water Seal Integrity Monitoring
REGULATION 12
MISCELLANEOUS STANDARDS OF PERFORMANCE
RULE 12
FLARES AT PETROLEUM REFINERIES
(Adopted July 20, 2005)

12-12-100 GENERAL

12-12-101 Description: The purpose of this rule is to reduce emissions from flares at petroleum refineries by minimizing the frequency and magnitude of flaring. Nothing in this rule should be construed to compromise refinery operations and practices with regard to safety.

12-12-110 Exemption, Organic Liquid Storage and Distribution: The provisions of this rule shall not apply to flares or thermal oxidizers used to control emissions exclusively from organic liquid storage vessels subject to Regulation 8, Rule 5 or exclusively from loading racks subject to Regulation 8 Rules 6, 33, or 39.

12-12-111 Exemption, Marine Vessel Loading Terminals: The provisions of this rule shall not apply to flares or thermal oxidizers used to control emissions exclusively from marine vessel loading terminals subject to Regulation 8, Rule 44.

12-12-112 Exemption, Wastewater Treatment Systems: The provisions of this rule shall not apply to flares or thermal oxidizers used to control emissions exclusively from wastewater treatment systems subject to Regulation 8, Rule 8.

12-12-113 Exemption, Pumps: The provisions of this rule shall not apply to thermal oxidizers used to control emissions exclusively from pump seals subject to Regulation 8, Rule 18. This exemption does not apply when emissions from a pump are routed to a flare header.

12-12-200 DEFINITIONS: For the purposes of this rule, the following definitions apply:

12-12-201 Emergency: A condition at a petroleum refinery beyond the reasonable control of the owner or operator requiring immediate corrective action to restore normal and safe operation that is caused by a sudden, infrequent and not reasonably preventable equipment failure, natural disaster, act of war or terrorism or external power curtailment, excluding power curtailment due to an interruptible power service agreement from a utility.

12-12-202 Feasible: Capable of being accomplished in a successful manner within a reasonable period of time, taking into account economic, environmental, legal, social and technological factors.

12-12-203 Flare: A combustion device that uses an open flame to burn combustible gases with combustion air provided by uncontrolled ambient air around the flame. This term includes both ground-level and elevated flares. When used as a verb, the term “flare” means the combustion of vent gas in a flare.

12-12-204 Flare Minimization Plan (FMP): A document intended to meet the requirements of Section 12-12-401.

12-12-205 Gas: The state of matter that has neither independent shape nor volume, but tends to expand indefinitely. Gas includes aerosols and the terms “gas” and “gases” are interchangeable.

12-12-206 Petroleum Refinery: A facility that processes petroleum, as defined in the North American Industrial Classification Standard No. 32411 and including any associated sulfur recovery plant.

12-12-207 Prevention Measure: A component, system, procedure or program that will minimize or eliminate flaring.

12-12-208 Reportable Flaring Event: Any flaring where more than 500,000 standard cubic feet per calendar day of vent gas is flared or where sulfur dioxide (SO₂) emissions are greater than 500 pounds per day. For flares that are operated as a backup,
staged or cascade system, the volume is determined on a cumulative basis; the total volume equals the total of vent gas flared at each flare in the system. For flaring lasting more than one calendar day, each day of flaring constitutes a separate flaring event unless the owner or operator demonstrates to the satisfaction of the APCO that the cause of flaring is the same for two or more consecutive days. A reportable flaring event ends when it can be demonstrated by monitoring required in Section 12-12-501 that the integrity of the water seal has been maintained sufficiently to prevent vent gas to the flare tip. For flares without water seals or water seal monitors as required by Section 12-12-501, a reportable flaring event ends when the rate of flow of vent gas falls below 0.5 feet per second. 

(Amended April 5, 2006)

12-12-209 Responsible Manager: An employee of the facility or corporation who possesses sufficient authority to take the actions required for compliance with this rule.

12-12-210 Shutdown: The intentional cessation of a petroleum refining process unit or a unit operation within a petroleum refining process unit due to lack of feedstock or the need to conduct periodic maintenance, replacement of equipment, repair or other operational requirements. A process unit includes subsets and components of the unit operation. Subsets and components includes but are not limited to reactors, heaters, vessels, columns, towers, pumps, compressors, exchangers, accumulators, valves, flanges, sample stations, pipelines or sections of pipelines.

12-12-211 Startup: The setting into operation of a petroleum refining process unit for purposes of production. A process unit includes subsets and components of the unit operation. Subsets and components includes but are not limited to reactors, heaters, vessels, columns, towers, pumps, compressors, exchangers, accumulators, valves, flanges, sample stations, pipelines or sections of pipelines.

12-12-212 Thermal Oxidizer: An enclosed or partially enclosed combustion device, other than a flare, that is used to oxidize combustible gases.

12-12-213 Vent Gas: Any gas directed to a flare excluding assisting air or steam, flare pilot gas, and any continuous purge gases.

12-12-300 STANDARDS

12-12-301 Flare Minimization: Effective November 1, 2006, flaring is prohibited unless it is consistent with an approved FMP and all commitments due under that plan have been met. This standard shall not apply if the APCO determines, based on an analysis conducted in accordance with Section 12-12-406, that the flaring is caused by an emergency and is necessary to prevent an accident, hazard or release of vent gas directly to the atmosphere.

12-12-400 ADMINISTRATIVE REQUIREMENTS

12-12-401 Flare Minimization Plan Requirements: The owner or operator of a petroleum refinery with one or more flares subject to this rule shall submit to the APCO a FMP in accordance with the schedule in Section 12-12-402. The FMP shall be certified and signed by a Responsible Manager and shall include, but not be limited to:

401.1 Technical Data: A description and technical information for each flare that is capable of receiving gases and the upstream equipment and processes that send gas to the flare including:

1.1 A detailed process flow diagram accurately depicting all pipelines, process units, flare gas recovery systems, water seals, surge drums and knock-out pots, compressors and other equipment that vent to each flare. At a minimum, this shall include full and accurate as-built dimensions and design capacities of the flare gas recovery systems, compressors, water seals, surge drums and knockout pots.

1.2 Full and accurate descriptions including locations of all associated monitoring and control equipment.
401.2 Reductions Previously Realized: A description of the equipment, processes and procedures installed or implemented within the last five years to reduce flaring. The description shall specify the year of installation.

401.3 Planned Reductions: A description 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.

401.4 Prevention Measures: A description and evaluation of prevention measures, including a schedule for the expeditious implementation of all feasible prevention measures, to address the following:

4.1 Flaring that has occurred or may reasonably be expected to occur during planned major maintenance activities, including startup and shutdown. The evaluation shall include a review of flaring that has occurred during these activities in the past five years, and shall consider the feasibility of performing these activities without flaring.

4.2 Flaring that may reasonably be expected to occur due to issues of gas quantity and quality. The evaluation shall include an audit of the vent gas recovery capacity of each flare system, the storage capacity available 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 shall consider the feasibility of reducing flaring through the recovery, treatment and use of the gas or other means.

4.3 Flaring caused by the recurrent failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner. The evaluation shall consider the adequacy of existing maintenance schedules and protocols for such equipment. For purposes of this Section, a failure is recurrent if it occurs more than twice during any five year period as a result of the same cause as identified in accordance with Section 12-12-406.

401.5 Any other information requested by the APCO as necessary to enable determination of compliance with applicable provisions of this rule.

Failure to implement and maintain any equipment, processes, procedures or prevention measures in the FMP is a violation of this section.

12-12-402 Submission of Flare Minimization Plans: On or before August 1, 2006, the owner or operator of a petroleum refinery with one or more flares subject to this rule shall submit a FMP as required by Section 12-12-401. On or before November 1, 2005 and every three months thereafter until a complete FMP is submitted, the owner or operator shall provide a status report detailing progress towards fulfilling the requirements of Section 12-12-401. Upon the submission of each status report, the APCO may require a consultation regarding the development of the plan to ensure that the plan meets the requirements of Section 12-12-401.

12-12-403 Review and Approval of Flare Minimization Plans: The procedure for determining whether the FMP meets the applicable requirements of this regulation is as follows:

403.1 Completeness Determination: Within 45 days of receipt of the FMP, the APCO will deem the plan complete if he determines that it includes the information required by Section 12-12-401. If the APCO determines that the proposed FMP is not complete, the APCO will notify the owner or operator in writing. The notification will specify the basis for this determination and the required corrective action.

403.2 Corrective Action: Upon receipt of such notification, the owner or operator shall correct the identified deficiencies and resubmit the proposed FMP within 45 days. If the APCO determines that the owner or operator failed to correct any deficiency identified in the notification, the APCO will disapprove the FMP.

403.3 Public Comment: The complete FMP (with exception of confidential information) will be made available to the public for 60 days. The APCO will
consider any written comments received during this period prior to approving or disapproving the FMP.

**403.4 Final Action:** Within 45 days of the close of the public comment period, the APCO will approve the FMP if he determines that the plan meets the requirements of Section 12-12-401, and shall provide written notification to the owner or operator. This period may be extended if necessary to comply with state law. If the APCO determines that the FMP does not meet the requirements of Section 12-12-401, the APCO will notify the owner or operator in writing. The notification will specify the basis for this determination. Upon receipt of such notification, the owner or operator shall correct the identified deficiencies and resubmit the FMP within 45 days. If the APCO determines that the owner or operator failed to correct any deficiency identified in the notification, the APCO will disapprove the FMP.

If the owner or operator submitted a complete FMP in accordance with Section 12-12-402, and the APCO has not disapproved the FMP under this section, the FMP shall be considered an approved FMP for the purposes of Section 12-12-301 until the APCO takes final action under Section 12-12-403.4.

**12-12-404 Update of Flare Minimization Plans:** The FMP shall be updated as follows:

404.1 No more than 12 months following approval of the original FMP and annually thereafter, the owner or operator of a flare subject to this rule shall review the FMP and revise the plan to incorporate any new prevention measures identified as a result of the analyses prescribed in Sections 12-12-401.4 and 12-12-406. The updates must be approved and signed by a Responsible Manager.

404.2 Prior to installing or modifying any equipment described in Section 12-12-401.1.1 that requires a District permit to operate, the owner or operator shall obtain an approved updated FMP addressing the new or modified equipment.

404.3 Annual FMP updates (with exception of confidential information) shall be made available to the public for 30 days. The APCO shall consider any written comments received during this period prior to approving or disapproving the update.

404.4 Within 45 days of the close of the public comment period, the APCO shall approve the FMP update if he determines that the update meets the requirements of Section 12-12-401, and shall provide written notification to the owner or operator. The previously approved FMP together with the approved update constitutes the approved plan for purposes of Section 12-12-301. This period may be extended if necessary to comply with state law. If the APCO determines that the FMP update does not meet the requirements of Section 12-12-401, the APCO will notify the owner or operator in writing. The notification will specify the basis for this determination and the required corrective action. Upon receipt of such notification, the owner or operator shall correct the identified deficiencies and resubmit the FMP update within 30 days. If the APCO determines that the owner or operator failed to correct the deficiencies identified in the notification, the APCO will disapprove the FMP update. For purposes of Section 12-12-301, disapproval of the update constitutes disapproval of the existing FMP, unless otherwise specified by the APCO.

404.5 If the owner or operator fails to submit a plan update as required by this Section, the APCO shall provide written notification of the lapse. If the owner or operator fails to submit an update within 30 days of receipt of the notification, the existing FMP shall no longer be considered an approved plan for purposes of Section 12-12-301.

**12-12-405 Notification of Flaring:** Effective August 20, 2005, the owner or operator of a flare subject to this rule shall notify the APCO as soon as possible, consistent with safe operation of the refinery, if the volume of vent gas flared exceeds 500,000 standard cubic feet.
cubic feet per calendar day. The notification, either by phone, fax or electronically, shall be in a format specified by the APCO and include the flare source name and number, the start date and time, and the end date and time.

12-12-406 Determination and Reporting of Cause: The owner or operator of a flare subject to this rule shall submit a report to the APCO within 60 days following the end of the month in which a reportable flaring event occurs. The report shall include, but is not limited to, the following:

406.1 The results of an investigation to determine the primary cause and contributing factors for the flaring event.

406.2 Any prevention measures that were considered or implemented to prevent recurrence together with a justification for rejecting any measures that were considered but not implemented.

406.3 If appropriate, an explanation of why the flaring is consistent with an approved FMP.

406.4 Where applicable, an explanation of why the flaring was an emergency and necessary to prevent an accident, hazard or release of vent gas to the atmosphere or where, due to a regulatory mandate to vent to a flare, it cannot be recovered, treated and used as fuel gas at the refinery.

406.5 The volume of vent gas flared, the calculated methane, non-methane hydrocarbon and sulfur dioxide emissions associated with the reportable flaring event.

(Amended April 5, 2006)

12-12-407 Deleted April 5, 2006

12-12-408 Designation of Confidential Information: When submitting the initial FMP, any updated FMP or any other report required by this Rule, the owner or operator shall designate as confidential any information claimed to be exempt from public disclosure under the California Public Records Act, Government Code section 6250 et seq. If a document is submitted that contains information designated confidential in accordance with this Section, the owner or operator shall provide a justification for this designation and shall submit a separate copy of the document with the information designated confidential redacted.

12-12-500 MONITORING AND RECORDS

12-12-501 Water Seal Integrity Monitoring: Effective August 1, 2006, the owner or operator of a flare subject to this rule with a water seal shall continuously monitor and record the water level and pressure of the water seal that services each flare. Any new installation of a water seal shall be subject to this requirement immediately. Records of these measurements shall be retained for one year. Monitoring devices required pursuant to this section shall be subject to the reporting and record keeping requirements of Regulation 1, Section 523: Parametric Monitors.
Bay Area Air Quality Management District
939 Ellis Street
San Francisco, CA 94109

Staff Report

Proposed Regulation
Regulation 12, Miscellaneous Standards of Performance
Rule 12, Flares at Petroleum Refineries

July 8, 2005

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# TABLE OF CONTENTS

I. EXECUTIVE SUMMARY........................................................................................................1

II. BACKGROUND.........................................................................................................................2
   A. Process Description ............................................................................................................2
   B. Bay Area District Regulations Applicable To Flares......................................................4
   C. Applicable Federal Regulations ......................................................................................5

III. POTENTIAL CONTROL STRATEGIES .............................................................................6

IV. REGULATORY PROPOSAL..................................................................................................7
   A. The Standard ....................................................................................................................7
   B. Administrative Requirements .........................................................................................8
   C. Monitoring And Records ...............................................................................................11
   D. Proposed Amendment to Regulation 8, Rule 2..............................................................11

V. EMISSIONS AND EMISSION REDUCTIONS....................................................................12
   A. Emissions ........................................................................................................................12
   B. Emission Reductions ........................................................................................................12

VI. ECONOMIC IMPACTS........................................................................................................17
   A. Introduction .....................................................................................................................17
   B. Discussion Of Elements .................................................................................................17
   C. Cost Analysis ..................................................................................................................20
   D. Socioeconomic Impacts ..................................................................................................23
   E. Incremental Costs ...........................................................................................................23
   F. District Staff Impacts .......................................................................................................24

VII. ENVIRONMENTAL IMPACTS .........................................................................................25

VIII. REGULATORY IMPACTS................................................................................................25

IX. RULE DEVELOPMENT PROCESS ....................................................................................27
   A. Technical Working Group ..............................................................................................27
   B. Stationary Source Committee Reports ...........................................................................28
   C. Public Meetings And Workshops ..................................................................................29

X. CONCLUSION .....................................................................................................................30

REFERENCES ..........................................................................................................................31

ATTACHMENTS:
APPENDIX A: SOCIOECONOMIC ANALYSIS
APPENDIX B: ENVIRONMENTAL IMPACT REPORT
APPENDIX C: COMMENTS & RESPONSES
APPENDIX D: FMP TIMELINE MATRIX
I. EXECUTIVE SUMMARY

Emissions from flaring at petroleum refineries have been an ongoing concern to the Bay Area Air Quality Management District and residents of the communities in the neighborhoods surrounding the refineries. Because flares are first and foremost a safety device that must be available for use in emergencies to prevent accident, hazard or release of refinery gas directly to the atmosphere, development of an appropriate regulatory mechanism to address flaring emissions has been a challenge. Through a broad participatory process involving District staff, refinery representatives, community representatives, representatives of local, state and federal public agencies, and other members of the interested public, however, the District has formulated a regulation that will reduce flaring emissions while providing refineries with flexibility to address their unique flare systems without compromising the safety of workers and the public, or the refineries.

Refinery flares are necessary for the safe disposal of gases generated during the refining process. These gases are collected by the refinery blowdown system, which gathers relief flow from process units throughout the refinery, separates liquid from vapors, recovers any condensable oil and water, and recovers gases for use in the refinery fuel system. When the heating value of the gas stream is insufficient for use as refinery fuel, when the stream is intermittent or when it exceeds the refinery’s capacity to recover and use the gas for use as a fuel, the blowdown system directs the vapors to the flare, which combusts the gases and prevents their direct uncontrolled release to the atmosphere.

The Bay Area Air Quality Management District (District) discussed the need to study the feasibility of implementing controls on refinery flaring as part of the San Francisco Bay Area 2001 Ozone Attainment Plan for the 1-Hour National Ozone Standard. Analysis of Further Study Measure 8 (FSM-8) for flares, blowdown systems and pressure relief devices was initiated in January of 2002. A draft Technical Assessment Document (TAD) for flares was released in December 2002. The TAD presented information on refinery flares and emission estimates, and was the foundation for the flare monitoring rule. The District’s flare monitoring rule, Regulation 12, Rule 11, was adopted by the District Board of Directors on June 4, 2003. Information obtained from the required monitoring was used to develop the proposed control strategies. The result is a proposed new rule, Regulation 12, Rule 12: Flares at Petroleum Refineries.

Emissions from flare operations at each Bay Area refinery have decreased since the District began work on development of the flare monitoring rule in 2002. Reports from refiners and analysis by staff have shown a reduction of total organics of approximately 85% since the time period covered by the TAD. These reductions are primarily due to adding flare gas compressor capacity and better management practices.
Emissions from refinery flares are currently estimated at 2 tons per day of total organic compounds (TOC) and 4 tons per day of sulfur dioxide (SO₂). These emission levels reflect the reductions realized as a result of actions taken by Bay Area refiners in recent years. The proposed regulation will capture these reductions to ensure no backsliding to flaring practices of the past. These emissions levels are expressed as daily averages, however; actual emissions on any given day range from 0 to 12 tons TOC and 0 to 61 tons of SO₂. The proposed rule calls for refiners to develop flare minimization plans to further reduce these emissions.

Staff investigated a variety of options for addressing emissions from refinery flares. The proposed regulation uses an approach that requires each refinery to develop a comprehensive plan to minimize flare use. Significant differences in refinery configurations and capacities to process and use gas in other processes require the rule to provide flexibility to implement the most appropriate flaring prevention measures for each refinery. The minimization plans will be developed in active consultation with District staff and will require annual updates to ensure that new technologies and practices will be identified and implemented in a process of continuous improvement. The plans will be made available for public review and written comment. A plan will only be approved if the APCO determines that all feasible flaring prevention measures have been considered and incorporated.

An Environmental Impact Report (EIR) was prepared to investigate and discuss elements of the proposed regulation that could result in environmental impacts. The EIR concludes that the proposed regulation would have no adverse environmental impact. A socioeconomic analysis mandated by Section 40728.5 of the Health and Safety Code was prepared by Applied Economic Development, Berkeley, California. The analysis concludes that the affected refineries should be able to absorb the costs of compliance with the rule without significant economic dislocation or loss of jobs.

As part of the technical assessment and rule development process a working group was formed that included representatives from the Bay Area petroleum refineries, the Western States Petroleum Association (WSPA), Communities for a Better Environment (CBE), the California Air Resources Board, and District staff. The workgroup met routinely to discuss technical issues including legal requirements of rule development, emission control strategies, monitoring techniques, standard definitions and investigation procedures. Summaries of these meetings are contained in Section IX of this report.

Additionally, staff hosted two evening public workshops in Martinez on March 24, 2005 and Richmond on, March 16, 2005, to receive input from the public on a proposed draft rule. The core issues raised at these meetings were: due consideration of safety, enforceability of the standards, clarity in definitions, the need for public input into the development of flare minimization plans, adequacy
of the breadth of flaring scenarios covered by the rule, and the need for a limit on the hydrogen sulfide content of the vent gas. The proposed rule includes revisions to the rule language presented at the workshops as necessary and appropriate to address these issues.

II. BACKGROUND

A. Process Description

Flares are first and foremost devices to ensure the safety of refinery operations and personnel. They also serve as emission control mechanisms for refinery blowdown systems. Blowdown systems collect and separate liquid and gaseous discharges from various process units and equipment throughout the refinery. They also collect gases that are the normal byproducts of a process unit or vessel depressurization, or that may result from an upset in a process unit, or that come from refinery process units during startup and shutdown, or when the balance between gas generation and the combustion of that gas for process heat is disrupted.

Blowdown systems generally recover liquids and send gases to the fuel gas system for use in refinery combustion. However, when the heating value of the gas stream is insufficient, when the stream is intermittent, or when the stream exceeds the refinery’s capacity to safely use the gas stream to satisfy refinery combustion needs, and the refinery does not have available storage capacity, the flare is used to combust these gases and prevent their direct uncontrolled release to the atmosphere.
The diagram above illustrates a typical flare system. The system is a component of the refinery blowdown system, which delivers gases and liquids to a knockout drum that captures liquids and directs them to the oil recovery stream. The gases are routed to the fuel gas system. The extent to which these gases can be captured depends upon the capacity of the compressors and the energy demand throughout the refinery. A refinery is said to be operating in good balance when gas generation during normal operation is consumed by demand requirements in the refining processes. As a general rule a refinery should be able to capture all of the gases delivered to the blowdown system during normal operations.

B. Bay Area Air Quality Management District Regulations Applicable to Flares

Several District rules apply to Bay Area refinery flare emissions, varying from the general to source specific requirements. The most recent is Regulation 12, Rule 11: Flare Monitoring at Petroleum Refineries, which was adopted on June 4,
2003. This rule requires refineries to accurately monitor the flow and composition of vent gases combusted in a flare, to calculate total organic (methane and non-methane organic compounds) and sulfur dioxide emissions, to identify reasons for and corrective actions taken to prevent major flaring events, to continuously video record flares subject to the rule, and to report this information to the District in a timely manner.

There are several other District regulations applicable to flare emissions. Regulation 1, Section 301: Public Nuisance, is derived from California Health and Safety Code Section 41700. It prohibits discharges that cause injury, detriment, nuisance, or annoyance to any considerable number of persons or to the public, or which endanger the comfort, repose, health, or safety of any such persons or the public, or which cause, or have a natural tendency to cause, injury or damage to business or property. Regulation 6: Particulate Matter and Visible Emissions, limits the quantity of particulate matter in the atmosphere through limitations on emission rates, concentration, visible emissions and opacity. Regulation 7: Odorous Compounds, places general limitations on odorous substances and specific emission limitations on certain odorous compounds. Regulation 9, Rule 1 and Rule 2: Inorganic Gaseous Pollutants for Sulfur Dioxide and Hydrogen Sulfide, limit ground level concentrations of these pollutants. Regulation 10 - Standards of Performance for New Stationary Sources, incorporates Federal standards for petroleum refineries adopted by reference.

Regulation 8, Rule 2 contains controls for organic compounds from miscellaneous operations. Although this regulation was not intended to apply to refinery flares and has not been enforced against these sources by the District, some confusion regarding the scope of this regulation exists. Staff proposes an amendment to Regulation 8, Rule 2, to clarify that this standard does not apply to refinery flares. This modification will resolve the existing confusion and will avoid any overlap or duplication of requirements applicable to refinery flares once Regulation 12-12 takes effect.

C. Applicable Federal Regulations

Federal New Source Performance Standards (NSPS) in 40 CFR Part 60, Subpart A, Section 60.18 applies to flares that are used as general control devices. Subpart A specifies design and operational criteria for new and modified flares. The requirements include monitoring to ensure that flares are operated and maintained in conformance with their designs. Flares are required to be monitored for the presence of a pilot flame using a thermocouple or equivalent device, to meet visible emissions standards, to maintain a minimum exit velocity and to meet a net heat content of the gas being combusted by the flare.

In addition, the NSPS limits sulfur oxides from combustion devices installed after June 11, 1973 (40 CFR Part 60, Subpart J, Section 60.104). Flaring of gases released due to upset conditions or as a result of relief valve leakage, startup/shutdown, or other emergency malfunctions is exempt from this standard.
Since 1998, EPA has pursued a coordinated, integrated compliance and enforcement strategy to address Clean Air Act compliance issues at the nation's petroleum refineries.

The National Petroleum Refinery Initiative\(^1\) addresses four compliance and enforcement issues under the federal Clean Air Act based on EPA’s determination that these concerns affect the petroleum refining industry nationwide:

- Prevention of Significant Deterioration/New Source Review (NSR);
- New Source Performance Standards (NSPS) for fuel gas combustion devices, including sulfur recovery plants, flares, heaters and boilers;
- Leak Detection and Repair requirements (LDAR); and
- Benzene National Emissions Standards for Hazardous Air Pollutants (BWON).

EPA has embarked on a series of multi-issue/multi-facility settlement negotiations with major petroleum refining companies. The settlements for the Bay Area refineries are specific to each refinery. In general, they include elements specific to catalytic cracking units, sulfur recovery plants and flares. One facility has entered into a settlement agreement that locks in the current status of flare operations. Other settlements seek to improve upon the current operating practices and require implementation schedules for application of the NSPS to all their flares. The details of these settlements are available on EPA’s website.

### III. POTENTIAL CONTROL STRATEGIES

Staff considered a variety of strategies to control emissions from flares. The traditional method of controlling emissions generally involves add-on devices that capture or reduce emissions, such as baghouses, scrubbers and low NOx burners. These devices are usually designed for a specific pollutant and emission source. They are not well suited for flares where combustion takes place in open air at the flare tip. Also, these control devices are designed for steady state operation making them inappropriate for a source like a flare that must go from burning only pilot gas to burning thousands of cubic feet of gas per second. Consequently, staff concluded that mandating the use of such devices to control emissions from flares generally is not a workable approach.

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\(^{1}\) EPA Website: [http://www.epa.gov/compliance/civil/programs/caa/oil/index.html](http://www.epa.gov/compliance/civil/programs/caa/oil/index.html), October 6th, 2004
Equipment control strategies applicable to refinery flare systems include those that require the installation of new equipment or devices, or physical changes to the flare system. Strategies that might be applied to these systems include:

- additional flare gas compressors to collect gases and prevent flaring;
- addition of gas storage capacity to hold flare gas;
- increasing gas treatment capacities;
- installation of redundant equipment;
- improvement of the reliability of the existing flare gas compressors;
- improvement of flare tip designs.

Pollution prevention strategies are designed to reduce emissions through changes to the operation of the refinery, as opposed to controlling the emissions with add-on equipment. These include:

- balancing the use of combustion devices, flare gas and natural gas consumption;
- developing management practices to minimize vent gases directed to the flare.

Since the beginning of the District’s technical assessment efforts in 2002, each refinery has implemented one or more of the strategies described above. The most significant of these involve installation of new flare gas recovery compressors at one refinery. Installation of additional compressor capacity and improvement of the reliability of the existing flare gas compressors at other refineries have also significantly reduced emissions. During the rule development process, refiners have presented trend charts to the District that show up to 60% reduction in emissions since 2002. Bay Area refiners and other participants in the work group meetings convened to assist in rule development generally concur with this assessment, but District staff as well as some members of the public have expressed concern over possible backsliding or failure to maintain those reductions. Staff concluded that the most workable strategy for reducing emissions from flaring is to require refiners to develop individual flare minimization plans. This strategy provides flexibility to maximize emission reductions among significantly different refinery process designs and has been crafted to maintain emission reductions from the practices already instituted by the refiners.

IV. REGULATORY PROPOSAL

PROPOSED NEW REGULATION 12, MISCELLANEOUS STANDARDS OF PERFORMANCE, RULE 12: FLARES AT PETROLEUM REFINERIES

A. THE STANDARD

The proposed regulation is to reduce emissions from flares at petroleum refineries by minimizing the frequency and magnitude of flaring. The proposal
includes a standard that prohibits the use of a refinery flare unless the use is consistent with an approved flare minimization plan ("FMP" or "Plan"). The rule includes a requirement to conduct a causal analysis to evaluate a reportable flaring event, i.e., flaring more than 500,000 standard cubic feet per calendar day, to identify the cause (or causes) of the flaring and the means to avoid flaring from that cause in the future if possible. In addition, each facility is required to submit an annual report to the District that includes an evaluation of flaring at volumes less than 500,000 where the calculated sulfur dioxide emissions are greater than 500 pounds. This formal evaluation process will ensure that each refinery makes continuous improvement and progress toward the goal to minimize use of refinery flares.

The standard recognizes that flares are safety devices and includes a provision to allow flaring in an emergency if necessary to prevent an accident, hazard or release of vent gas directly to the atmosphere. To ensure that this exemption is properly applied, the proposed rule relies on the causal analysis to confirm that only flaring necessary for the safe operation of the refinery due to an emergency is allowed under this provision.

While the proposal will not eliminate all non-emergency flaring immediately, it will maintain reductions achieved by Bay Area refiners over the past few years and help identify areas where additional reductions are possible. Refiners will be required to update the plan annually to incorporate newly identified preventive measures to ensure continuous improvement over time and progress toward the goal to minimize use of refinery flares.

Certain flares are exempt from the requirements of the proposed rule. These exemptions apply to any flare that functions as an abatement device used exclusively for the following sources: organic liquid storage and distribution, marine vessel loading terminals, wastewater treatment plants, and pumps. Standards for these sources are specified in other District regulations. They include, but are not limited to abatement efficiency, use of good engineering practices, and emission limits depending on the source operation. Emission data from these source-specific applications are submitted annually to the District. Monitoring and control of these systems are well managed within this existing structure.

B. ADMINISTRATIVE REQUIREMENTS
The proposal specifies the required elements of a flare minimization plan; lays out the process that the APCO will use to evaluate and approve the FMP and updates; identifies the criteria for submission of the initial FMP and FMP updates; requires investigation into the cause of flaring and timely notification to the APCO; and specifies the procedures for submittal and designation of confidential information.
The FMP is not intended to serve as a permit for a flare or to be included as part of the refinery permit; thus the plan is not subject to provisions of the Health and Safety Code or District rules related to permits. If the plan includes a commitment to install new equipment or to modify existing equipment or to take any other action that would trigger the requirement to obtain a permit from the District, the owner or operator must obtain the required permit in a separate process in accordance with applicable District permitting rules.

Refiners will be required to include all feasible prevention measures in the FMP with a schedule for expeditious implementation of those measures. The elements of a FMP include:

1) A description of and technical information for the refinery flare system and the upstream equipment and processes that send gas to the flare, including all associated monitoring and control equipment;
2) A description of the equipment, processes and procedures previously installed or implemented by the owner or operator within the last five years to reduce the flaring;
3) A description of any equipment, process or procedure to reduce flaring that is planned, but not yet installed or implemented and the schedule for completion;
4) A description and evaluation of prevention measures, including a schedule to expeditiously implement the following:
   • flaring during planned major maintenance activities including startup and shutdown;
   • flaring that may occur due to issues of gas quantity or quality;
   • flaring caused by the recurrent breakdown of equipment;
5) Any other information requested by the Air Pollution Control Officer as necessary to enable determination of compliance with applicable provisions of this rule.

The schedule for submitting a flare minimization plan requires the owner or operator of a flare subject to the rule to submit a complete plan within a year of rule adoption. The proposed rule also requires the refiner to demonstrate that it is making progress toward development and timely submission of a complete plan beginning three months after adoption of the rule and every three months thereafter. Ongoing consultation with the APCO will ensure that any problems are identified and addressed early in the process.

The review and approval process allows time for the APCO to make an administrative determination that the FMP is complete and for facilities to make any corrections to address any deficiencies identified by the APCO before the substantive review of the plan is initiated. Once the APCO determines that the plan addresses all the required elements, it will be made available for 60 days for public review and comment. In addition to the complete plans, the quarterly status reports are public records and will be available for review upon request. In providing a lengthy public review and comment period at the earliest stage of the
substantive review of the plans, the process ensures meaningful public participation at the point in time when it will be most informed and most effective.

The District’s substantive review process will involve an analysis of the prevention measures considered in the plan, including the completeness of the universe of measures identified, the feasibility determination for those measures, and the reasonableness of implementation schedule for the feasible measures. Following this review, including consideration of written public comment, the APCO will approve the FMP if he determines that it complies with the procedural and substantive requirements of the rule.

The proposed regulation includes language allowing a refiner to use a flare consistent with a complete FMP pending final action by the APCO on the plan. This prohibition is necessary because the prohibition on flaring takes effect November 1, 2006. In the event that the APCO has not taken final action on a refiner’s initial FMP submission, rather than further delay implementation of the standard, the rule allows a refiner that has submitted a complete plan to flare in accordance with that plan until the APCO takes final action to approve or disapprove the plan. This provision does not signify that the plan is or will be approved.

Updates of FMPs are required annually to incorporate any significant changes in process equipment or operational procedures related to flares. In addition, an update is required prior to installing or modifying any equipment associated with flare systems that would require a District Authority to Construct. This provision requires refineries to consider the impact on flaring when installing or modifying equipment. After the initial implementation phase of the flare control rule, experience may indicate that the frequency of updates may need adjustment. At that point, District staff will reassess this requirement and may recommend to the Board in a future rulemaking that the frequency of updates could be adjusted to enhance the regulation.

Refiners will also be required to submit an annual report covering less significant flaring with sulfur emissions of concern (greater than 500 pounds per day). This report must identify the reason for flaring and describe any prevention measures considered or implemented. Any prevention measure implemented must be included in the annual update of the FMP. Having refiners examine smaller flaring events serves the continuous improvement goal of the proposed rule.

The proposed rule includes a requirement to notify the District of flaring of gas in excess of 500,000 standard cubic feet per calendar day. This will provide the District and the public with timely information about flare operations. Under current regulations, refiners do not have to notify the District of a flaring event unless there is an indicated excess on a ground level monitor (within 96 hours) or they are seeking breakdown relief under Regulation 1 (immediately, with due regard for safety), which is available for equipment failures but not operator error.
The new proposal would ensure that the District receives information regarding flaring in a timely manner (as soon as possible consistent with safe operation of the refinery) in all cases where the trigger level is exceeded.

The proposed rule requires the flare owner or operator to determine and report the cause of a reportable flaring event. The investigation must be sufficient to determine the primary cause and contributing factors that resulted in flaring. This level of investigation is necessary to ensure that sufficient information is available to develop prevention measures to eliminate the recurrence of avoidable flaring. Currently the flare monitoring rule, Regulation 12, Rule 11, requires reporting of the cause of flaring more than 1 million standard cubic feet of vent gas. Over the past two years, the District has worked closely with refinery personnel preparing those reports to ensure that the investigations conducted are sufficient to provide the information necessary to identify measures to reduce or eliminate such flaring, and that reporting of the results of those investigations is complete. The language of the proposed rule is intended to require that the same level of investigation and reporting is provided for flaring of 500,000 scf under the proposed rule.

C. MONITORING AND RECORDS
The proposed rule requires continuous monitoring of the water seal. The “knockout water seal drum” performs three functions. First, the drum provides final vapor-liquid disengaging (“knockout”) to reduce the potential for liquid carryover up the flare stack. Second, the drum provides a positive barrier or “water seal” between the flare gas header and flare stack. This prevents air in the flare stack from back flowing into the flare gas header and potentially forming an explosive mixture with the hydrocarbon vapors. An inert gas purge (such as nitrogen) may also be added at the base of the flare stack as “sweep gas” to prevent air from back flowing from the flare tip into the flare gas header. Third, the drum provides backpressure on the flare gas header to operate a flare gas recovery compressor. The recovery compressor collects vapors in the flare gas header that would otherwise be combusted in the flare, and returns those vapors to the refinery fuel gas system.\(^2\) The flare owner or operator must record and archive the monitoring data to verify the integrity, or proper operational status, of the flare’s water seal. These data are indicators of actual flow to the flare and are measured by flow of makeup water, the water seal height or system pressure. Records of these measurements will assist in verification of calculated emissions and investigations into the cause of flaring.

D. PROPOSED AMENDMENT TO REGULATION 8, ORGANIC COMPOUNDS, RULE 2: MISCELLANEOUS OPERATIONS

Staff is also proposing to amend Regulation 8, Rule 2, to clarify that flares are not subject to that rule.

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\(^2\) Excerpt from Flare Control Workgroup meeting by Clark Hopper, Valero Refinery
V. EMISSIONS AND EMISSION REDUCTIONS

A. Emissions

Flares produce air pollutants through two primary mechanisms. The first mechanism is incomplete combustion of a gas stream. Like all combustion devices, flares do not combust all of the fuel directed to them. Combustion efficiency reflects the extent to which the oxidation reactions that occur in combustion are complete reactions converting the gases entering the flare into fully oxidized combustion products. Combustion efficiency may be stated in terms of the extent to which all gases entering the flare are combusted, typically called "overall combustion efficiency" or simply "combustion efficiency", or it may be stated as the efficiency of combustion for some constituent of the flare gas as, for example, "hydrocarbon destruction efficiency."

The second mechanism of pollutant generation is the oxidation of flare gases to form other pollutants. As an example, the gases that are burned in flares typically contain sulfur in varying amounts. Combustion oxidizes these sulfur compounds to form sulfur dioxide, a criteria pollutant. In addition, combustion also produces relatively minor amounts of nitrogen oxides through oxidation of the nitrogen in flare gas or atmospheric nitrogen in combustion air.

Unlike internal combustion devices like engines and turbines, flares combust fuel in the open air. Because combustion products are not contained and emitted through a stack, a duct, or an exhaust pipe, emission measurement is very problematic. Studies can be conducted on scale-model flares under a hood or in a wind tunnel where all combustion products can be captured. Any results for these small flares must be adjusted with scaling factors if they are to be applied to full-size flares. For full-size operating industrial flares, which can have a diameter of four feet or more and a stack height of 100 feet or more, all combustion products cannot be captured and measured. To study emissions from these flares, emissions can be sampled with test probes attached to the stack, a tower, or a crane. Emissions can also be studied using remote sensing technologies like open-path Fourier transform infrared (FTIR) or differential absorption lidar (DIAL). In applying the results of any particular study to a specific flare or flare type, it is important to note any differences in flare design and construction. For example, some flares are simply open pipes, while others, like most refinery flares, have flare tips that are engineered to promote flare vent gas mixing to maximize combustion efficiency. In addition, studies suggest that composition and BTU content of gas burned, gas flow rates, flare operating conditions, and environmental factors like wind speed can affect, to varying extents, the efficiency of flare combustion.

B. Emission Reductions

While the District staff was studying flare emissions during the TAD period, the Tesoro Refinery was in the process of installing a fuel gas compressor capital improvement project to recover hydrocarbons previously sent to the flare.
Tesoro added an additional 8 million standard cubic feet of recovery capacity to the flare system. This project significantly reduced the volume of gases flared and emissions from flaring. Additionally, all the refineries instituted programs to reduce flaring. Measures implemented include improvements in flare gas compressor reliability, prolonging the interval between major maintenance activities, better process controls during startup and shutdown, source reduction efforts and increased scrutiny of flare gas systems.

**Characterizing Flare Emissions**

When the District staff examines the emissions from an air pollution source category, the air pollution emission estimates are typically expressed on an annual average basis (usually tons per day) determined from reported annual process throughput or reported emissions. For large, intermittent emission sources such as refinery flares, this air pollution emission estimation process can be quite challenging. First, there is the cyclic nature of refinery process unit startups and shutdowns. Major refining units at a petroleum refinery typically go five years between turnaround events. Until recently, the District’s inventory excluded episodic emissions and Bay Area refineries were not required to measure the quantities of vent gases sent to their flare systems. Therefore, engineering assumptions had to be made to estimate air pollution emissions with limited information. While daily emissions based on annual averages are consistent with standard emission inventory practices, on any given day, actual refinery flare emissions can vary significantly. The day-to-day variation for the period of June 1, 2001 through September 1, 2002, is shown in Figure 2.

![Figure 2. Distribution of Total Organics (tons per day) for the period of June 1, 2001 through September 1, 2002](image)

**Estimating Minimum Flow in Calculating Flare Emissions**

In the past, there was a wide variation in the quality of flare monitoring instrumentation. The limit of detection of the instrumentation, the lower limit
where vent gas flows could be detected, was not state-of-the-art. Under typical operating situations, water seals prevent refinery gases from venting to a flare until a certain positive pressure is achieved. Once that positive pressure is exceeded, the refinery gases pass through the water seal and then are combusted in the flare.

The potential exists for refinery gases to travel through the water seal at some nominal flow less than the limit of detection for the monitoring instrumentation that was in place during the TAD period. Pressure surging, percolation, inadequate or fluctuating water levels, or water seal design may allow refinery gases to reach the flare. To address concerns about minimum flows that could not be easily detected by the instrumentation, District staff investigated several methods to quantify these emissions. One method was to examine correlations between pressure and level indications at the water seal and the flow meter readings. This method presented limitations for some flare systems. In some instances the pressure measuring devices were located in different locations or at long distances from the water seal, possibly providing measurements that may not represent the actual water seal pressure. Where District staff identified proper installations of the water seal instrumentation, the readings were used to adjust minimum flow data.

Where the District staff identified issues with using water seal data, an alternative method was used. Staff considered the variation in flow meter technologies used during the TAD period, the limits of detection and reliability of the meters, refinery design and operational status that could generate flow to the flare, and then estimated minimum flow emissions at a value equal to 50% of the minimum limit of detection. The total contribution of this minimum flow emission estimate is approximately 1 ton per day of total organic emissions during the flare TAD study period.

**The TAD Emission Estimates**

The emission inventory for refinery flares prior to the Flare Monitoring Rule was included in the Draft December 2002 Technical Assessment Document (TAD). In order to develop emission information for the TAD, the District asked the refineries to submit flow and composition data on their flare systems for the period of January 1, 2001 to August 31, 2002. Some refineries had no monitoring, some used fairly new ultrasonic monitoring systems. To compensate for the wide-variation in the quality of information provided, staff used engineering assumptions and estimated from the information submitted that emissions from flares were approximately 22 tons/day of total organic emissions.

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3 Uncertainties regarding minimum flows have been greatly reduced due to improved instrumentation requirements that specify much lower limits of detection. These requirements of Regulation 12, Rule 11 became effective in December 2003.

4 Assumptions used for that estimate are: 1) emissions are averaged per day of flare use, 2) a flare gas composition of 75% hydrocarbon, and 3) a hydrocarbon molecular weight of 44.
compounds. As described below, subsequent efforts indicate that the TAD significantly overestimated flare emissions.

**Updated TAD Emission Estimates**

The initial emission estimate in the flare TAD caused the refineries to question District staff’s analysis and the data submittals themselves. District staff spent considerable time working with each refinery to review the available data and replace the overall averages used in the TAD with refinery-specific information that is more representative of each refinery’s flare emissions. Since the publishing of the TAD, the refineries have submitted several modifications to their original data submittals and have met with District staff on numerous occasions to clarify their data re-submittals. After evaluating the data re-submittals and developing refinery-specific gas composition and hydrocarbon molecular weight estimates, staff have revised the emission estimate from flares, on an annual average basis, to approximately 8 tons/day of total organic compounds (5 tons/day of non-methane organic compounds) during the TAD period. Additionally, staff now estimates flare emissions for the period of time covered by the TAD to include approximately 20 tons/day of SO\textsubscript{X} for the time period June 1, 2001 through September 1, 2002. The daily emissions ranged from 2.5 to 55 tons/day of total organic compounds, and from 6 to 55 tons/day SO\textsubscript{X} during the TAD data period.

**Current Flare Emission Estimates**

The data from the refineries that have been submitted since adoption of the monitoring rule indicates that flare flows have been reduced compared to flows during the TAD data period. Much of the reduction is due to the installation of additional compressors at the Tesoro refinery and better management practices at all of the refineries. Figure 3 illustrates the trend since implementation of the flow measuring requirement in the flare monitoring rule.

![Figure 3. Total Organic Emission Trend](image-url)
The graph illustrates four characteristics of refinery operations relative to flaring: 1) general operations through May 2004, 2) episodic emissions around June 2004, 3) general operations with emphasis on reductions during July 2004 to September 2004, and 4) major maintenance activities at several refineries from September through November 2004. The values represented in this figure are based on the assumption that no flow occurs when the water seal remains intact or the flow rate is less than 0.5 feet per second (lower limit of accuracy for ultrasonic flow meters).

Staff evaluated the reported data and characterized emissions using the assumption that any positive reading represents flow to the flare tip. Figure 3 illustrates the breakdown per facility for total organic emissions from vent, pilot and purge gas on an average daily basis for 2004.

The emission estimate from flares, on an average daily basis for all facilities in 2004, was approximately 2 tons/day of total organic compounds (approximately 1.5 tons/day of non-methane organic compounds). A monthly distribution for each facility is illustrated in Figure 4. The daily emissions ranged from 0 to 12 tons/day of total organic compounds. For sulfur dioxide, the average daily basis was approximately 4 tons/day and ranged from 0 to 61 tons/day.
VI. ECONOMIC IMPACTS

A. Introduction

This section discusses the estimated costs associated with the proposed rule. The California Health & Safety Code states, in part, that districts shall endeavor to achieve and maintain state ambient air quality standards for ozone, carbon monoxide, sulfur dioxide, and nitrogen dioxide by the earliest practicable date. In developing regulations to achieve this objective, districts shall consider the cost-effectiveness of their air quality programs, rules, regulations, and enforcement practices in addition to other relevant factors, and shall strive to achieve the most efficient methods of air pollution control. However, priority shall be placed upon expeditious progress toward the goal of healthful air.5

A number of unique factors come into play in the analysis of the cost of the proposed flare control rule. First, many of the benefits of the flare control rule, at least those expected in the early years of implementation, have already been achieved and the associated costs have been incurred by the refineries. Second, a number of the controls refineries will implement to reduce flaring will provide additional operational or economic benefits to the refinery operations, thus offsetting costs. For this reason, the costs of compliance presented below provide a very conservative picture.

Non-typical factors affect the cost-effectiveness analysis as well. For example, because emissions from flares are episodic, the use of annualized emissions provides a much less meaningful picture of cost effectiveness for the proposed flare control rule than for a standard control measure to control emissions from more stable sources or operations. In fact, the reduction or elimination of flaring will have far more significant benefits during a day when flaring would have occurred – particularly a day when the amount of gas flared is at the high end of the events that have occurred historically and can be expected to occur in the future – than during an hypothetical day with annualized flaring emissions.

Moreover, because the proposed rule requires refineries to develop the prevention measures they will implement to reduce flaring, the regulation ensures that the most cost effective means for achieving this goal will be implemented. That is, it is reasonable to expect that each refinery, given the flexibility provided by the structure of the rule, will include the most cost-effective prevention measures available for each iteration of the flare minimization plan, thus insuring the continuous improvement at the least cost.

B. Discussion of Elements

Development of a Flare Minimization Plan
Staff estimated the cost of developing the FMP document based on the workload

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5 California Health and Safety Code Section 40910
encountered during development of materials mandated by the Contra Costa County Safety Ordinance. The safety ordinance requires a hazard analysis for each process unit. This structure is nearly identical to the FMP, although the level of detail in the analysis would be substantially less under the proposed rule. The difference is due to the narrower focus of the FMP; it targets flare minimization while the hazard analysis required consideration of the “entire universe” of potential impacts. The approximate cost of a hazard analysis was $12,000 per process unit. This assumes 3.5 refinery staff at $35 per hour, a professional facilitator to assist in developing the analysis at $150 per hour, and 32 days\textsuperscript{6} to develop the report.\textsuperscript{7} Applying these values to a medium sized refinery, the cost for developing a FMP is approximately $100,000.

**Implementation of Prevention Measures**

The costs associated with implementing a flare minimization plan will vary depending on the status of the individual flare systems. Some systems may need only minor adjustments to existing operating procedures while others may need substantial modifications to incorporate design changes.

The precise costs for implementing a plan are difficult to determine prior to evaluating the specific elements of the plan. Refiners did not provide this level of detail during the workgroup process due to concerns over liability and trade secret information. Discussions with refiners regarding prevention measures already implemented or planned for study have lead to a general consensus that $20,000,000 represents a fair estimate of the high end of the range of costs.

To demonstrate the range of cost, staff considered alternatives to the high end, for example where a facility has already achieved the most feasible level of emission reductions. Staff estimated the range to be from $100,000 for minor modifications to potentially well over $20,000,000 for systems needing additional recovery and scrubbing capacities.

**Notification of Flaring**

The trigger level for this requirement is 500,000 standard cubic feet in any calendar day. The cost is dependant on the number of flaring days exceeding the volume trigger. The data from the flare monitoring monthly reports shows 243 occurrences where the volume of vent gas flared was greater than 500,000 standard cubic feet per day in 2004 for all facilities.\textsuperscript{8} Based on this information and assuming 15 minutes per call at a rate of $30.00 per person hour, staff estimated the total cost for all facilities of notifying the District and providing the necessary information would be approximately $1,800 for all facilities per year. The cost for an individual refinery is expected to be much less, and in some cases zero cost.\textsuperscript{9}

\textsuperscript{6} Excludes administrative review and approval.
\textsuperscript{7} Based on phone conversations with affected refineries.
\textsuperscript{8} The majority, 88 occurrences, are from one flare with the same reported cause of flaring.
\textsuperscript{9} Maintaining levels indicated in the 2004 Flare Monitoring Reports
Determination and Reporting of Cause
The cost for this requirement is dependant on the number of reportable flaring events and the complexity of the event. The data from the flare monitoring monthly reports shows 243 occurrences where the volume of vent gas flared was greater than 500,000 standard cubic feet per day (MMSCFD) in 2004 for all facilities. Regulation 12, Rule 11: Flare Monitoring at Petroleum Refineries requires investigation into and reporting of flaring events. The new requirement expands the scope of events requiring investigation because the trigger drops from 1,000,000 to 500,000, and it requires greater detail for all reportable events, including a thorough investigation into the cause and contributing factors, a description of prevention measures considered and justification for those not implemented, and identification of issues that require the use of a flare including safety considerations and regulatory mandates. To adjust for these differences, staff assumed an increase in the hourly rate to $50.00 per hour for 12 hours per event. The result was an estimate of approximately $145,800 for all facilities per year. Again the cost for an individual refinery will be much less. Moreover, staff expects this value to drop in time as facilities minimize the number of events and become more proficient in investigations.

Annual Reports and Updates
The proposed rule requires an annual report that summarizes flare usage when the flow rate is less than 500,000 standard cubic feet per day where the sulfur dioxide emissions are greater than 500 pounds. Flare monitoring data for 2004 indicates an additional 20 events for all facilities meeting the reporting criteria will occur. Additionally, the proposed rule requires the FMP to be updated annually to incorporate any new prevention measures identified as a result of the causal analysis and annual updates. Staff expects the complexity of these reports to be far less than the FMPs. Based on these factors staff estimates the annual reports and updates will cost less than one third of the cost of the FMP, or $30,000 for each.

Water Seal Integrity
The costs associated with this provision are dependant on the need to upgrade current monitoring systems on water seals. Several refineries have systems that are already configured for continuous monitoring and recording. Other systems would need upgrades, including water level and drum pressure measuring devices, hardwiring to data recording systems, and administrative procedures. For those systems that require upgrades, about half, the primary cost is hardwiring to the control room and is a function of the distance. The cost might be reduced by choosing an alternative such as wireless, however, confidence in this technology is not known. Staff considered a system that would require only minor upgrades and arrived at an estimate of $100,000 for the first year. Annual costs thereafter include periodic maintenance and data handling. This cost was estimated at $3,000 per year.
C. Cost Analysis

The proposed rule is intended to reduce emissions from flares by minimizing the frequency and magnitude of flaring. This is accomplished by requiring each refinery to develop a flare minimization plan (FMP). The primary function of the plan is to set a schedule for implementing feasible flaring prevention measures. Refiners will be required to investigate the cause of all significant flaring and to update the FMP annually to incorporate the means identified to prevent recurrence. The initial FMP will prevent backsliding from those emission reductions that have already occurred by codifying those efforts as part of the plan.

Table 1 shows the costs associated with the proposed rule. Costs for individual refineries will vary significantly depending on the number and complexity of flares and flare systems and the amount of reduction already achieved. Following the table is a discussion of each provision. The provisions listed in the table include both one-time and recurring costs. The non-recurring costs are those associated with development of the FMP and the upgrades for water seal monitoring. About half of the monitoring systems would need an upgrade. The recurring costs in Table 1 are based on the scenario where significant flaring has occurred. These costs are likely to decrease in time as the level of flaring is minimized.

<table>
<thead>
<tr>
<th>Provision</th>
<th>Estimated Cost</th>
<th>Assumptions</th>
</tr>
</thead>
<tbody>
<tr>
<td>FMP Development(^a)</td>
<td>100,000</td>
<td>1/3 of an average hazard analysis(^b) for a medium size facility</td>
</tr>
<tr>
<td>Prevention Measure</td>
<td>1,900,000</td>
<td>$20,000,000 project amortized over 20 year lifespan at 7%</td>
</tr>
<tr>
<td>(High End)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>FMP Updates</td>
<td>30,000</td>
<td>Approximately 1/3 of a full FMP</td>
</tr>
<tr>
<td>Notification of Flaring</td>
<td>500</td>
<td>67 notifications(^c)</td>
</tr>
<tr>
<td>Causal Analysis</td>
<td>40,200</td>
<td>$50/hr for 12 hours per event for 67 events(^d)</td>
</tr>
<tr>
<td>Annual Reports</td>
<td>30,000</td>
<td>Approximately 1/3 of a full FMP</td>
</tr>
<tr>
<td>Water Seal Monitoring</td>
<td>9,000(^e)</td>
<td>Partial upgrade; amortized over 20 year lifespan at 7%</td>
</tr>
</tbody>
</table>

\(^a\) One time cost  
\(^b\) Hazop for the Contra Costa County Safety Ordinance  
\(^c\) Data from monthly reporting pursuant to the District’s Flare Monitoring Rule  
\(^d\) Time based on pilot program during technical assessment, 2001  
\(^e\) Includes $3,000 for direct annual or recurring cost, and $6,000 non-recurring upgrade costs

Based on the example given in Table 1, the cost for a hypothetical refinery that must undertake a significant capital improvement project, such as the addition of compressor capacity, is approximately $2,100,000 for the first year. The total cost for the proposed rule would not be this calculated cost times the number of
flare systems. Each flare system is unique and would have a unique set of feasible prevention measures at a variety of costs. However, this hypothetical provides an example approaching the upper bound of the cost range. Costs for a typical Bay Area flare is expected to be less.

As an alternative scenario staff considered a refinery that only implements an enhanced I&M program or other type of operational control, or is able to demonstrate no flare usage and therefore only needs to memorialize existing practices. Using Table 1 provisions for FMP updates, annual reports and recurring costs for monitoring, the recurring cost is approximately $63,000. This hypothetical provides the lower bound of the cost range.

**COST EFFECTIVENESS ESTIMATE**

Even though a traditional cost-effectiveness analysis is expected to be conservative due to various factors as discussed above, i.e., the use of average daily emissions, which tend to underestimate expected emission reductions from preventing a period of flaring, and the flexibility built into the proposed rule, which is expected to result in refiners selecting the most cost-effective means of reducing emissions from flaring, the following analysis – based on the traditional model – still supports a finding that the proposed rule is cost effective.

**Case Studies**

To demonstrate the cost effectiveness of equipment modifications, staff considered two scenarios that have already been implemented. Both involve modifications to the vent gas recovery compressors. The first involved a reliability study and implementation of measures used to improve performance of existing compressors. The second involved an increase in the recovery capacity of the compressors. Although the cost of implementation is similar – approximately $20,000,000 – the reductions achieved differ significantly. Table 2 shows the estimated emissions over the time period for these projects.

<table>
<thead>
<tr>
<th>Facility</th>
<th>Year</th>
<th>Organics (tons/day)</th>
<th>SOx (tons/day)</th>
<th>CO (tons/day)</th>
<th>NOx (tons/day)</th>
<th>PM (tons/day)</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Case 1</td>
<td>2002</td>
<td>0.73</td>
<td>0.95</td>
<td>0.11</td>
<td>0.06</td>
<td>0.01</td>
<td>1.86</td>
</tr>
<tr>
<td></td>
<td>2003</td>
<td>0.18</td>
<td>0.41</td>
<td>0.04</td>
<td>0.02</td>
<td>0.01</td>
<td>0.66</td>
</tr>
<tr>
<td>Case 2</td>
<td>2002</td>
<td>3.93</td>
<td>13.6</td>
<td>0.59</td>
<td>0.59</td>
<td>0.09</td>
<td>18.8</td>
</tr>
<tr>
<td></td>
<td>2003</td>
<td>0.32</td>
<td>2.21</td>
<td>0.05</td>
<td>0.03</td>
<td>0.01</td>
<td>2.61</td>
</tr>
</tbody>
</table>

a Until the flare monitoring rule was adopted (June 2003) Bay Area refineries were not required to measure the quantities of vent gases sent to their flare systems. Therefore, engineering assumptions had to be made to estimate air pollution emissions with limited information.

b Total organics including vent, pilot and purge gas. Methane varies significantly; average content
is ~ 30%
\(^c\) Assumes all sulfur as hydrogen sulfide oxidized to sulfur dioxide
\(^d\) Calculated using AP42 emission factors
\(^e\) Calculated using AP42 emission factors assuming no visible emissions

For the first case, the total emissions as indicated in Table 2 decreased from a total of 1.86 tons per day prior to the reliability study, to a total of 0.66 tons per day, after implementing the reliability improvements. This represents a 65% reduction. For the second case, the total emissions decreased from 18.8 tpd to 2.61 tpd after the equipment upgrade. This represents approximately an 86% reduction.

At a twenty year amortized cost of 7%, equipment costs for each of the two case studies is $1,921,592 per year. The cost effectiveness for Case 1 is about $40,000 per ton for total organics, $9600 per ton for SOx, and $4,300 per ton for all pollutants combined. The cost effectiveness for Case 2 is about $1,580 per ton for total organics, $443 per ton for SOx, and $341 per ton for all pollutants combined. Despite the many factors that indicate these estimates are conservative, this analysis demonstrates that the proposed rule is cost effective for all pollutants and exceeds the range for hydrocarbon only in comparison to Best Available Control Technology guidelines.

Tables 3 and 4 include the cost of the administrative requirements of the rule with the equipment costs. Table 3 shows the estimated costs using as an example a facility that has performed a hazard analysis for Contra Costa County and has upgraded the flare gas recovery system. It is intended to represent a more costly prevention measure. Table 4 gives an example of a less costly measure in which startup and shutdown schedule adjustments result in a reduction of flaring and add lost production.

Table 3. Estimated Costs for High Cost Prevention Measure

<table>
<thead>
<tr>
<th>Provision</th>
<th>Estimated Cost ($/Year)</th>
<th>Assumptions</th>
</tr>
</thead>
<tbody>
<tr>
<td>FMP Development</td>
<td>100,000</td>
<td>1/3 of an average hazard analysis for a medium size facility</td>
</tr>
<tr>
<td>Prevention Measure</td>
<td>1,921,592</td>
<td>Flare gas recovery compressor project; amortized over 20 years at 7%</td>
</tr>
<tr>
<td>FMP Updates</td>
<td>30,000</td>
<td>1/3 of a full FMP</td>
</tr>
<tr>
<td>Notification of Flaring</td>
<td>500</td>
<td>67 notifications</td>
</tr>
<tr>
<td>Causal Analysis</td>
<td>40,200</td>
<td>$50/hr for 12 hours per event for 67 events</td>
</tr>
<tr>
<td>Annual Reports</td>
<td>10,950</td>
<td>Enhanced daily log:1 hr/day at $30/hour for 365 days</td>
</tr>
<tr>
<td>Monitoring</td>
<td>9,000</td>
<td>Partial upgrade; amortized over 20 years at 7%</td>
</tr>
</tbody>
</table>
It is important to note that all items except the FMP development and the prevention measure are recurring costs that will decrease in time. The estimated cost of the prevention measure listed in Table 3 is for a specific system and would be substantially reduced after implementation. The cost could vary significantly for different systems and should not be assumed to be the same for any other system. However, recovery upgrade projects at other facilities were cited in this general price range.

Table 4. Estimated Costs for a Low Cost Prevention Measure

<table>
<thead>
<tr>
<th>Provision</th>
<th>Estimated Cost ($/Year)</th>
<th>Assumptions</th>
</tr>
</thead>
<tbody>
<tr>
<td>FMP Development</td>
<td>100,000</td>
<td>1/3 of an average hazard analysis for a medium size facility</td>
</tr>
<tr>
<td>Prevention Measure</td>
<td>121,945</td>
<td>Startup/Shutdown schedule adjustments including lost production costs; 5 year lifespan</td>
</tr>
<tr>
<td>FMP Updates</td>
<td>30,000</td>
<td>Approximately 1/3 of a full FMP</td>
</tr>
<tr>
<td>Notification of Flaring</td>
<td>50</td>
<td>7 notifications</td>
</tr>
<tr>
<td>Causal Analysis</td>
<td>4,200</td>
<td>$50/hr for 12 hours per event for 7 events</td>
</tr>
<tr>
<td>Annual Reports</td>
<td>10,950</td>
<td>Enhanced daily log: 1 hr/day at $30/hour for 365 days</td>
</tr>
<tr>
<td>Monitoring</td>
<td>3,000</td>
<td>No upgrades</td>
</tr>
</tbody>
</table>

The cost effectiveness for the high cost prevention measure would be $1,603 per ton for the first year for all pollutants, $1,527 per ton thereafter. For the low cost prevention measure the cost effectiveness would be $1,298 per ton for all pollutants, and $818 per ton thereafter.

D. Socioeconomic Impacts

Section 40728.5 of the Health and Safety Code requires an air district to assess the socioeconomic impacts of the adoption, amendment, or repeal of a rule if the rule is one that “will significantly affect air quality or emissions limitations.” Applied Economic Development, Berkeley, California, has prepared a socioeconomic analysis. The analysis concludes that the affected refineries should be able to absorb the costs of compliance with the proposed rule without significant economic dislocation or loss of jobs. The socioeconomic analysis is attached as Appendix A.

E. Incremental Costs

Under California Health and Safety Code Section 40920.6, the District is required to perform an incremental cost analysis for a proposed rule under certain circumstances. To perform this analysis, the District must (1) identify one or
more control options achieving the emission reduction objectives for the proposed rule, (2) determine the cost effectiveness for each option, and (3) calculate the incremental cost effectiveness for each option. To determine incremental costs, the District must “calculate 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.”

To determine the incremental cost, staff used a case study (Case 2, Table 2) that considers reductions achieved since installation of capital equipment, and future implementation of a potential control option with a corresponding emission reduction based on historical reductions. The capital equipment installed was two new compressors rated at 4 MMSCFD each and was operational in the first quarter of 2003. The estimated cost was $20,000,000. The emission inventory for NMHC in tons per day, based on flare monitoring data received during the technical assessment and in accordance with the flare monitoring rule, indicated 3.07, 0.25 and 0.45 for 2002, 2003 and 2004, respectively.

The NMHC reduction in 2003 was 2.82 tons per day, or 92%. Assuming comparable reductions and a potential control option with a cost of $40,000,000, the incremental cost is calculated at approximately $8,300,000. This is an example of a “most costly” scenario. For comparison, assuming the same reductions at a lower cost, for example $500,000, the incremental cost is calculated at approximately $207,500.

The proposed concept is to evaluate each flare system to identify where reductions may be available for that particular system, develop a plan most suited for that system, then operate in a manner consistent with the plan. It is dissimilar to traditional regulatory mandates due to the variation of the flare systems and the emission reduction potential for each of those systems. The incremental cost is specific to the individual system rather than applicable to the entire source category. This approach adds greater certainty to the selection of the most feasible measure.

F. District Staff Impacts

Implementing this rule will require a total of 1.5 FTE at an average staff level of a Senior Engineer. The actual personnel involved will likely include Senior and Supervising Inspectors assigned to refineries, a Principal Specialist and a Principal Engineer to coordinate review of flare minimization plans, and Source Test Engineers and Technicians to review water seal monitoring systems.

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10 This figure represents an estimate of the total project costs. A breakdown of costs was not provided, is likely to be less and is not applicable to any other project.
11 Methane was approximately 22% of the total organic emissions.
12 This assumption recognizes that flaring will not be eliminated.
13 This value was stated during workgroup meetings and is an estimate for one day of loss in production, for example to extend a startup.
Causal analysis review should take no more than an hour for 90% of the flaring events, however, for the 10% of the events (24, based on 2004 flaring events) that are large, emergency events, a week of an inspector’s time and several days of an engineer’s time may be needed. A Senior Engineer level (top step) costs $149,000 at 1.5 FTE. In addition, management review, particularly for first year plans and major event analyses, will add to the costs. Management staff involvement would include personnel from the Enforcement, Engineering and Technical Divisions, with some oversight by the Deputy APCOs and the APCO. The total cost will exceed $250,000.

On June 15, the Board adopted a schedule of fees that shifted refinery flares from Schedule G1 to Schedule 3, which will result in approximately an additional $178,000 in revenue from these sources. The calculations above are only for the increase in costs for this proposal. Significant additional costs have been incurred over the last several years from investigation of complaints and implementation of the flare monitoring rule (Reg. 12, Rule 11). One Air Quality Specialist currently allocates 40% of his time to quality assurance of the monitoring reports and coordinating refinery work groups in the Enforcement Division, at a cost of $34,000.

VII. ENVIRONMENTAL IMPACTS

Pursuant to the California Environmental Quality Act, the District’s environmental consultant, Environmental Audit, Inc., has prepared an Environmental Impact Report (EIR) for the proposed rule to determine whether it would result in any significant environmental impacts. The EIR concludes that the proposed rule would not have any adverse impacts. The EIR including comments and responses is attached as Appendix B.

VIII. REGULATORY IMPACTS

Section 40727.2 of the Health and Safety Code requires an air district, in adopting, amending, or repealing an air district regulation, to identify existing federal and district air pollution control requirements for the equipment or source type affected by the proposed change in district rules. The district must then note any differences between these existing requirements and the requirements imposed by the proposed change. Table 5 is a matrix of the proposed rule, existing Bay Area regulations, and federal requirements for flares.
### Table 5. Regulatory Matrix

<table>
<thead>
<tr>
<th>Agency</th>
<th>Regulation</th>
<th>Control/Performance Requirements</th>
<th>Monitoring Requirements</th>
<th>Emission Limitations</th>
</tr>
</thead>
<tbody>
<tr>
<td>BAAQMD</td>
<td>Reg. 2, Rule 6 (Title V permit)</td>
<td>Specific to facility and source</td>
<td>Specific to facility and source</td>
<td>Throughput (lbs/hr vent gas), Visible emissions</td>
</tr>
<tr>
<td>BAAQMD</td>
<td>Proposed Reg. 12, Rule 12</td>
<td>Prohibits flaring without or not in accordance with a flare minimization plan.</td>
<td>Water seal pressure and level.</td>
<td>Minimize Flaring</td>
</tr>
<tr>
<td>EPA</td>
<td>40 CFR 60.18 (applies to flares subject to NSPS)</td>
<td>Pilot flame present at all times, heat content, maximum tip velocity, composition</td>
<td>Presence of flame, heating value</td>
<td>Smokeless capacity</td>
</tr>
<tr>
<td>EPA</td>
<td>Subpart J</td>
<td>Limits on gases other than those due to malfunction, relief valve leakage and emergencies.</td>
<td>Hydrogen sulfide in fuel gas</td>
<td>Hydrogen sulfide in fuel gas</td>
</tr>
</tbody>
</table>

### Federal Requirements

Federal New Source Performance Standards (NSPS) in 40 CFR Part 60, Subpart A, Section 60.18 apply to flares that are used as general control devices. They specify design and operational criteria for new and modified flares. The requirements include monitoring to ensure that flares are operated and maintained in conformance with their designs. Flares are required to be monitored for the presence of a pilot flame using a thermocouple or equivalent device. Other parameters to be monitored include visible emissions, exit velocity and net heat content of the gas being combusted by the flare.

In addition, the NSPS limit sulfur oxides in vent gases combusted in a flare installed after June 11, 1973 (40 CFR Part 60, Subpart J, Section 60.104). Upset gases or fuel gas that is flared as a result of relief valve leakage or other emergency malfunctions is exempt from the standard. As discussed above, EPA has entered into consent decrees with all Bay Area refineries. These decrees, among other requirements, contain increments of progress for the application of NSPS standards to all flares.
IX. RULE DEVELOPMENT PROCESS

As part of the development of this regulation staff have undertaken an extensive rule development process in order to receive input from all affected parties. These efforts included the formation of a technical working group, public meetings, workshops and presentations to the District Board Stationary Source Committee. The following is a discussion of these efforts.

A. Technical Working Group

To assist in the TAD and rule development process a technical working group was formed that included representatives from Industry, Communities for a Better Environment (CBE), California Air Resources Board, and District staff. This workgroup met routinely to discuss technical issues. The issues discussed include the significance of emission levels, potential control strategies, legal requirements for rule development and sharing of confidential information, current flare system monitoring, procedures to determine the cause of flaring, and the most effective means to distribute information to the public. The following is a summary of those meetings:

August 7, December 10, and January 13, 2003
The topics included the Technical Assessment Document (TAD) update, flare use categories and control strategies, and the rule development schedule. The discussion focused on the basis to update the District’s initial assessment, how to identify the causes of flaring and how to develop appropriate control strategies.

March 19, 2004
The topics included technical assessment of emissions and flare control proposals. The discussion of the basis for updating the District’s initial assessment, how to identify the cause of flaring and develop appropriate control strategies was continued from the previous meeting.

June 11, 2004
The topics included status update and timelines, final TAD revision, flare control proposals, definitions, and web casting. Staff presented a tentative schedule for rule development, an updated assessment of the flare TAD, proposals for controlling emissions from flares, definitions of various terms and text based web casting of flare monitoring data.

November 4, 2004
A professional facilitator was added to the workgroup for this and subsequent meetings. The topics included agenda review, flare control rule status, workgroup discussion ground rules, possible categories of flaring events, and definitions of terms. The discussion focused on meeting process, developing categories for the cause of flaring, and using terms consistently.
December 2, 2004  
This meeting consisted of individual presentations by the Western States Petroleum Association, Communities for a Better Environment, and the District. The focus was on the procedure to evaluate the significance of flare events and the appropriate action to establish control strategies.

December 14, 2004  
The topics included flaring information for determining cause, verification of low flow regimes, water seal integrity, and characterization of flare gas composition. The discussion focused on root cause analysis as the standard for investigating the reasons for flaring, monitoring devices on water seals, and current sampling protocols.

January 11, 2005  
Workgroup members discussed the purpose, approach and essential elements of a flare control rule. A list of findings/issues was developed, with general agreement that a management plan for reducing emissions from flares is appropriate.

February 8, 2005  
The meeting focused on two issues that had been developed at the prior meeting; thresholds for the casual analysis and expectations for a management plan.

The group reached consensus on the need to meet individually for future meetings. Subsequently, staff and District management met with representatives of the refineries, the Western States Petroleum Association, Communities for a Better Environment and the Plumbers and Steamfitters Local 342. In addition, numerous phone conversations between District staff and individual refineries occurred to gather information on the specific designs and operating practices for each flare system.

B. Stationary Source Committee Reports  
At the flare monitoring rule adoption hearing, staff committed to provide an update to the Stationary Source Committee eighteen months after rule adoption. At the November 11, 2004 meeting, staff provided a report on the implementation of Regulation 12, Rule 11: Flare Monitoring at Petroleum Refineries, flare emissions information, and flare control rule development progress. In addition to staff’s presentation, WSPA and CBE gave presentations. The minutes of that meeting can be found on the District’s web site at (http://www.baaqmd.gov/brd/brddirectors/agendas_minutes_2004.asp).

Three additional presentations were given to the Stationary Source Committee: one on January 24, 2005, one on March 28, 2005, and one on May 23, 2005. The presentations provided progress reports regarding rule development and accomplishments since November 11, 2004, the last Stationary Source meeting.
The reports included background materials, an update on emission characterizations, workgroup progress, reports on the public workshops, response to public comments, and plans for finalizing this rule development process.

C. Public Meetings and Workshops
The staff of the Bay Area Air Quality Management District conducted public meetings in four different locations to discuss flare systems at petroleum refineries. The purpose of the meetings was to present information on the flare control measure and to receive input. These evening meetings were held on October 23, 2003 at the Crockett Community Center, October 29, 2003 at the Maple Hall Civic Center in San Pablo, November 5, 2003 at the Benicia City Council Chambers, and November 6, 2003 at the Martinez City Council Chambers. The input provided by the public was used in developing a draft rule.

A draft rule was presented at two public workshops held in Martinez on March 16, 2005 and in Richmond on March 24, 2005. Both meetings were held in the evening and combined were attended by over 200 people. The two core issues raised at the workshops concerned the perceived lack of clearly defined standards and the desire to have the rule provide an opportunity for public comment on the flare minimization plans. Staff made modifications to the proposed rule to address both of these concerns.

Written comments on the draft rule were received from the Western States Petroleum Association, Communities for a Better Environment, the Plumbers and Steamfitters Local 342, American Lung Association, Valero Refinery, EPA, ARB, Global Community Monitor, Clean Water Action and Community Labor Refinery Tracking Committee, Ohio Citizen Action, Louisiana Bucket Brigade, Inform Public Relations, Center for Environmental Health, Pamela Calvert, Bob Craft, Norma Wallace, Molly Boggs, and Peter Hendricks. In addition, one phone message was received from Shirley Butt. All were supportive of the District’s effort to develop a flare control rule and made suggestions for improvement. Staff made modifications to the proposed rule to address the comments and suggestions.

This proposed rule was made available for public comment and posted on the District’s web site. Staff has continued to meet with workgroup members to discuss the proposed rule. Written comments and staff responses will be contained in an addendum to this Staff Report (Appendix C), which will be prepared following the July 12, 2005 close of the public comment period on the regulatory proposals.

Appendix D contains a matrix of the timeline for the FMP submittal, public comment, and review and approval process.
X. CONCLUSION

The proposed rule, Regulation 12, Rule 12: Flares at Petroleum Refineries, is intended to limit the amount of emissions released from flares by limiting the frequency and magnitude of flaring events. Pursuant to Health and Safety Code Section 40727, new regulations must meet necessity, authority, clarity, consistency, non-duplicity and reference. The proposed regulation is:

• Necessary to protect public health by reducing ozone precursor emissions. The amendments also reduce exposures to toxic air contaminants, sulfur dioxide and particulate matter.

• Authorized by California Health and Safety Code Section 40702.

• Clear, in that the new regulation specifically delineates the affected industry, compliance options and administrative requirements for industry subject to this rule,

• Consistent with other District rules, and not in conflict with state or federal law,

• Non-duplicative of other statutes, rules or regulations, and

• The proposed regulation properly references the applicable District rules and test methods and does not reference other existing law.

An Environmental Impact Report prepared by Environmental Audit, Inc., concludes that there will be no adverse environmental impacts from adoption of the proposed rule. A socioeconomic analysis prepared by Applied Development Economics concludes that the affected refineries will be able to absorb the costs of compliance with the proposed rule without economic dislocation or loss of jobs.

Staff recommends the adoption of the proposed new Regulation 12: Miscellaneous Standards of Performance, Rule 12: Flares at Petroleum Refineries, the proposed amendment to Regulation 8: Organic Compounds, Rule 2: Miscellaneous Operations, and certification of the Final Environmental Impact Report.
REFERENCES


4. California Health and Safety Code, CHAPTER 10, “District Plans To Attain State Ambient Air Quality Standards”, Section 40910
1.0 Purpose

To limit the emissions of volatile organic compounds (VOC), oxides of nitrogen (NOx), and sulfur oxides (SOx) from the operation of flares.

2.0 Applicability

This rule is applicable to operations involving the use of flares.

3.0 Definitions

3.1 Air-Assisted Flare: a combustion device where forced air is injected to promote turbulence for mixing and to provide combustion air.

3.2 Air Pollution Control Officer (APCO): as defined in Rule 1020 (Definitions).

3.3 Air Resources Board (ARB): as defined in Rule 1020 (Definitions).

3.4 British Thermal Unit (Btu): the amount of heat required to raise the temperature of one pound of water from 59°F to 60°F at one atmosphere.

3.5 Calendar Day: any day starting at twelve o’clock AM and ending at 11:59 PM.

3.6 Coanda Effect Flare: A flare in which the high pressure flare gas flows along a curved surface inspirating air into the gas to promote combustion.

3.7 Emergency: any situation or a condition arising from a sudden and reasonably unforeseeable and unpreventable event beyond the control of the operator. Examples include, but are not limited to, not preventable equipment failure, natural disaster, act of war or terrorism, or external power curtailment, excluding a power curtailment due to an interruptible power service agreement from a utility. A flaring event due to improperly designed equipment, lack of preventative maintenance, careless or improper operation, operator error or willful misconduct does not qualify as an emergency. An emergency situation requires immediate corrective action to restore safe operation. A planned flaring event shall not be considered as an emergency.

3.8 Enclosed Flare: a flare composed of multiple gas burners that are grouped in an enclosure, and are staged to operate at a wide range of flow rates.
3.9 EPA: United States Environmental Protection Agency.

3.10 Feasible: Capable of being accomplished in a successful manner within a reasonable period of time, taking into account economic, environmental, legal, social, and technological factors.

3.11 Flare: a direct combustion device in which air and all combustible gases react at the burner with the objective of complete and instantaneous oxidation of the combustible gases. Flares are used either continuously or intermittently and are not equipped with devices for fuel-air mix control or for temperature control.

3.12 Flare Event: any intentional or unintentional combustion of vent gas in a flare. The flare event ends when the flow velocity drops below 0.12 feet per second or when the 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 APCO in the Flare Monitoring and Recording Plan. For a flare event that continues for more than one calendar day, each calendar day or venting of gases shall constitute a separate flare event.

3.13 Flare Gas: gas burned in a flare.

3.14 Flare Minimization Plan (FMP): a document intended to meet the requirements of Section 6.5 of this Rule.

3.15 Flare Monitoring System: all flare monitoring and recording equipment used for the determination of flare operating parameters. Flare monitoring and recording equipment includes, but is not limited to, sample systems, transducers, transmitters, data acquisition equipment, data recording equipment, and video monitoring equipment and video recording equipment.

3.16 Flexigas: a low BTU fuel gas produced by gasifying coke produced in a fluid-bed Coker. Due to the air used in the gasifying process, Flexigas is approximately 50% nitrogen.

3.17 Gaseous Fuel: any gases used as combustion fuel which include, but are not limited to, any natural, process, synthetic, landfill, sewage digester, or waste gases. Gaseous fuels include produced gas, pilot gas and, when burned, purge gas.

3.18 MMBtu: million British thermal units.

3.19 Non-Assisted Flare: a combustion device without any auxiliary provision for enhancing the mixing of air into its flame. This definition does not include those flares that by design provide excess air at the flare tip.
3.20 NOx: any nitrogen oxide compounds

3.21 Open Flare: a vertically or horizontally oriented open pipe flare from which gases are released into the air before combustion is commenced.

3.22 Operator: includes, but not limited to, any person who owns, leases, supervises, or operates a facility.

3.23 Petroleum Refinery: a facility that processes petroleum, as defined in the Standard Industrial Classification Manual as Industry No. 2911, Petroleum Refining. 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.

3.24 Pilot: an auxiliary burner used to ignite the vent gas routed to a flare.

3.25 Pilot Gas: the gas used to maintain the presence of a flame for ignition of vent gases.

3.26 Planned Flaring: a flaring operation that constitutes a designed and planned process at a source, and which would have been reasonably foreseen ahead of its actual occurrence, or is scheduled to occur. Planned flaring includes, but is not limited to, the following flaring activities:

3.26.1 Oil or gas well tests, well related work, tests ordered by a regulatory agency.

3.26.2 Equipment depressurization for maintenance purposes.

3.26.3 Equipment start-up or shutdown.

3.26.4 Flaring of gas at production sources where no gas handling, gas injection or gas transmission facilities exists.

3.26.5 Flaring of off-specification gas (i.e. non-PUC quality gas), unless the operator can demonstrate that the gas must be flared for engineering or safety reasons, e.g., under emergency.

3.26.6 The operation of a flare for the purpose of performing equipment maintenance.

3.27 Prevention Measure: a component, system, procedure, or program that will minimize or eliminate flaring.
3.28 Public Utilities Commission (PUC) Quality Gas: any gaseous fuel, gas containing fuel where the sulfur content is no more than one-fourth (0.25) grain of hydrogen sulfide per one hundred (100) standard cubic feet and no more than five grains of total sulfur per one hundred (100) standard cubic feet. PUC quality gas shall also mean high methane (at least 80% by volume) gas as specified in PUC's General Order 58-A.

3.29 Purge Gas: Nitrogen, carbon dioxide, liquefied petroleum gas, refinery fuel gas, or natural gas, any of which can be used to maintain a non-explosive mixture of gases in the flare header or provide sufficient exit velocity to prevent any regressive flame travel back into the flare header.

3.30 Refinery Fuel Gas: a combustible gas, which is a by-product of the refinery process.

3.31 Reportable Flaring Event: any flaring where more than 500,000 standard cubic feet of vent gas is flared per calendar day, or where sulfur oxide emissions are greater than 500 pounds per calendar day. A reportable flaring event ends when it can be demonstrated by monitoring required in Section 6.8 that the integrity of the water seal has been maintained sufficiently to prevent vent gas to the flare tip. For flares without water seals or water seal monitors as required by Section 6.8, a reportable flaring event ends when the rate of flow of vent gas falls below 0.12 feet per second.

3.32 Representative Sample: a sample of vent gas collected from the location as approved for flare monitoring and analyzed utilizing test methods specified in Section 6.3.4.

3.33 Shutdown: 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.

3.34 Startup: 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.

3.35 Steam-Assisted Flare: a combustion device where steam is injected into the combustion zone to promote turbulence for the mixing of the combustion air before it is introduced to the flame.

3.36 Thermal oxidizer: an enclosed or partially enclosed combustion device, other than a flare, that is used to oxidize combustible gases.
3.37 Total Organic Gases (TOG): all hydrocarbon compounds containing hydrogen and carbon with or without other chemical elements.

3.38 Turnaround: a planned activity involving shutdown and startup of one or several process units for the purpose of performing periodic maintenance, repair, replacement of equipment or installation of new equipment.

3.39 Vent Gas: any gas directed into a flare, excluding assisting air or steam, flare pilot gas, and any continuous purge gases.

3.40 Volatile Organic Compound (VOC): as defined in Rule 1020 (Definitions).

3.41 Water Seal: a liquid barrier, or seal, to prevent the passage of gas. Water seals provide a positive means of flash-back prevention in addition to enabling the upstream flare system header to operate at a slight positive pressure at all times.

4.0 Exemptions

4.1 Flares operated in municipal solid waste landfills subject to the requirements of Rule 4642 (Solid Waste Disposal Sites) are exempt from this rule.

4.2 Flares that are subject to the requirements of 40 CFR 60 Subpart WWW (Standards of Performance for Municipal Waste Landfills), or Subpart Cc (Emission Guidelines and Compliance Times for Municipal Solid Waste Landfills) are exempt from this rule.

4.3 Except for the recordkeeping requirements in Section 6.1.4 the requirements of this rule shall not apply to any stationary source that has the potential to emit, for all processes, less than ten (10.0) tons per year of VOC and less than ten (10.0) tons per year of NOx.
5.0 Requirements

The operator of any source subject to this rule shall comply with the following requirements:

5.1 Flares that are permitted to operate only during an emergency are not subject to the requirements of Sections 5.6 and 5.7.

5.2 The flame shall be present at all times when combustible gases are vented through the flare.

5.3 The outlet shall be equipped with an automatic ignition system, or, shall operate with a pilot flame present at all times when combustible gases are vented through the flare, except during purge periods for automatic-ignition equipped flares.

5.4 Except for flares equipped with a flow-sensing ignition system, a heat sensing device such as a thermocouple, ultraviolet beam sensor, infrared sensor, or an alternative equivalent device, capable of continuously detecting at least one pilot flame or the flare flame is present shall be installed and operated.

5.5 Flares that use flow-sensing automatic ignition systems and which do not use a continuous flame pilot shall use purge gas for purging.

5.6 Open flares (air-assisted, steam-assisted, or non-assisted) in which the flare gas pressure is less than 5 psig shall be operated in such a manner that meets the provisions of 40 CFR 60.18. The requirements of this section shall not apply to Coanda effect flares.

5.7 Ground-level enclosed flares shall meet the following emission standards:

<table>
<thead>
<tr>
<th>Type of Flare and Heat Release Rate in MMBtu/hr</th>
<th>VOC (lb/MMBtu)</th>
<th>NOx (lb/MMBtu)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Without Steam-assist</td>
<td></td>
<td></td>
</tr>
<tr>
<td>&lt; 10 MMBtu</td>
<td>0.0051</td>
<td>0.0952</td>
</tr>
<tr>
<td>10-100 MMBtu</td>
<td>0.0027</td>
<td>0.1330</td>
</tr>
<tr>
<td>&gt; 100 MMBtu</td>
<td>0.0013</td>
<td>0.5240</td>
</tr>
<tr>
<td>With Steam-assist</td>
<td></td>
<td></td>
</tr>
<tr>
<td>All</td>
<td>0.14 as TOG</td>
<td>0.068</td>
</tr>
</tbody>
</table>
5.8 Flare Minimization Plan

Effective on and after July 1, 2011, flaring is prohibited unless it is consistent with an approved flare minimization plan (FMP), pursuant to Section 6.5, and all commitments listed in that plan have been met. This standard shall not apply if the APCO determines that the flaring is caused by an emergency as defined by Section 3.7 and is necessary to prevent an accident, hazard or release of vent gas directly to the atmosphere.

5.9 Petroleum Refinery SO\(_2\) Performance Targets

5.9.1 Effective on and after January 1, 2011, the operator of a petroleum refinery shall minimize sulfur dioxide flare emissions to less than 1.50 tons per million barrels of crude processing capacity, calculated as an average over one calendar year.

5.9.2 Effective on and after January 1, 2017, the operator of a petroleum refinery shall minimize sulfur dioxide flare emissions to less than 0.50 tons per million barrels of crude processing capacity, calculated as an average over one calendar year.

5.10 Effective on and after July 1, 2011, the operator of a flare subject to flare minimization requirements pursuant to Section 5.8 shall monitor the vent gas flow to the flare with a flow measuring device or other parameters as specified in the Permit to Operate. The operator shall maintain records pursuant to Section 6.1.7. Flares that the operator can verify, based on permit conditions, are not capable of producing reportable flare events pursuant to Section 6.2.2 shall not be required to monitor vent gas flow to the flare.

5.11 Effective on and after July 1, 2011, the operator of a petroleum refinery or a flare with a flaring capacity equal to or greater than 50 MMBtu/hr shall monitor the flare pursuant to Sections 6.6, 6.7, 6.8, 6.9, and 6.10.

6.0 Administrative Requirements

6.1 Recordkeeping

The following records shall be maintained, retained on-site for a minimum of five years, and made available to the APCO, ARB, and EPA upon request:

6.1.1 Copy of the compliance determination conducted pursuant to Section 6.4.1.

6.1.2 Copy of the source testing result conducted pursuant to Section 6.4.2.
6.1.3 For flares used during an emergency, record of the duration of flare operation, amount of gas burned, and the nature of the emergency situation.

6.1.4 Operators claiming an exemption pursuant to Section 4.3 shall record annual throughput, material usage, or other information necessary to demonstrate an exemption under that section.

6.1.5 Effective on and after July 1, 2011, a copy of the approved flare minimization plan pursuant to Section 6.5.

6.1.6 Effective on and after July 1, 2012, where applicable, a copy of annual reports submitted to the APCO pursuant to Section 6.2.

6.1.7 Effective on and after July 1, 2011, where applicable, monitoring data collected pursuant to Sections 5.10, 6.6, 6.7, 6.8, 6.9, and 6.10.

6.2 Flare Reporting

6.2.1 Unplanned Flaring Event

Effective on and after July 1, 2011, the operator of a flare subject to flare minimization plans pursuant to Section 5.8 of this rule shall notify the APCO of an unplanned flaring event within 24 hours after the start of the next business day or within 24 hours of their discovery, which ever occurs first. The notification shall include the flare source identification, the start date and time, and the end date and time.

6.2.2 Reportable Flaring Event

Effective on and after July 1, 2012, and annually thereafter, the operator of a flare subject to flare minimization plans pursuant to Section 5.8 shall submit an annual report to the APCO that summarizes all Reportable Flaring Events as defined in Section 3.0 that occurred during the previous 12 month period. The report shall be submitted within 30 days following the end of the twelve month period of the previous year. The report shall include, but is not limited to all of the following:

6.2.2.1 The results of an investigation to determine the primary cause and contributing factors of the flaring event;

6.2.2.2 Any prevention measures considered or implemented to prevent recurrence together with a justification for rejecting any measures that were considered but not implemented;
6.2.2.3 If appropriate, an explanation of why the flaring was an emergency and necessary to prevent accident, hazard or release of vent gas to the atmosphere, or where, due to a regulatory mandate to vent a flare, it cannot be recovered, treated and used as a fuel gas at the facility; and

6.2.2.4 The date, time, and duration of the flaring event.

6.2.3 Annual Monitoring Report

Effective on and after July 1, 2012, and annually thereafter, the operator of a flare subject to flare monitoring requirements pursuant to Sections 5.10, 6.6, 6.7, 6.8, 6.9, and 6.10, as appropriate, shall submit an annual report to the APCO within 30 days following the end of each 12 month period. The report shall include the following:

6.2.3.1 The total volumetric flow of vent gas in standard cubic feet for each day.

6.2.3.2 Hydrogen sulfide content, methane content, and hydrocarbon content of vent gas composition pursuant to Section 6.6.

6.2.3.3 If vent gas composition is monitored by a continuous analyzer or analyzers pursuant to Section 5.11, average total hydrocarbon content by volume, average methane content by volume, and depending upon the analytical method used pursuant to Section 6.3.4, total reduced sulfur content by volume or hydrogen sulfide content by volume of vent gas flared for each hour of the month.

6.2.3.4 If the flow monitor used pursuant to Section 5.10 measures molecular weight, the average molecular weight for each hour of each month.

6.2.3.5 For any pilot and purge gas used, the type of gas used, the volumetric flow for each day and for each month, and the means used to determine flow.

6.2.3.6 Flare monitoring system downtime periods, including dates and times.

6.2.3.7 For each day and for each month provide calculated sulfur dioxide emissions.
6.2.3.8 A flow verification report for each flare subject to this rule. The flow verification report shall include flow verification testing pursuant to Section 6.3.5.

6.3 Test Methods

The test methods listed below shall be used to demonstrate compliance with this rule. Alternate equivalent test methods may be used provided the test methods have been approved by the APCO and EPA.

6.3.1 VOC, measured and calculated as carbon, shall be determined by EPA Method 25, except when the outlet concentration must be below 50 ppm in order to meet the standard, in which case Method 25a may be used, and analysis of halogenated exempt compounds shall be analyzed by EPA Method 18 or ARB Method 422 “Determination of Volatile organic Compounds in Emission from Stationary Sources”. The VOC concentration in ppmv shall be converted to pounds per million Btu (lb/MMBtu) by using the following equation:

\[
\text{VOC in lb/MMBtu} = \frac{(\text{ppmv } \text{dry}) \times (F, \text{dscf} / \text{MMBtu})}{(1.135 \times 10^8) \times (20.9 - \%O_2)}
\]

Where: \( F \) = As determined by EPA Method 19

6.3.2 NOx emissions in pounds per million BTU shall be determined by using EPA Method 19.

6.3.3 NOx and \( O_2 \) concentrations shall be determined by using EPA Method 3A, EPA Method 7E, or ARB 100.

6.3.4 Testing and Sampling Methods for Flare Monitoring

Effective on and after July 1, 2011 operators subject to vent gas composition monitoring requirements pursuant to Section 6.6 shall use the following test methods as appropriate, or by an alternative method approved by the APCO, ARB and EPA:

6.3.4.1 Total hydrocarbon content and methane content of vent gas shall be determined using ASTM Method D 1945-96, ASTM Method UOP 539-97, EPA Method 18, or EPA Method 25A or 25B,

6.3.4.3 If vent gas composition is monitored with a continuous analyzer employing gas chromatography the minimum sampling frequency shall be one sample every 30 minutes.

6.3.4.4 If vent gas composition is monitored using continuous analyzers not employing gas chromatography, the total reduced sulfur content of vent gas shall be determined by using EPA Method D4468-85.

6.3.5 Flow Verification Test Methods

For purposes of the flow verification report required by Section 6.2.3.8, vent gas flow shall be determined using one or more of the following methods, or by any alternative method approved by the APCO, ARB, and EPA:

6.3.5.1 EPA Methods 1 and 2;

6.3.5.2 A verification method recommended by the manufacturer of the flow monitoring equipment installed pursuant to Section 5.10.

6.3.5.3 Tracer gas dilution or velocity.

6.3.5.4 Other flow monitors or process monitors that can provide comparison data on a vent stream that is being directed past the ultrasonic flow meter.

6.4 Compliance Determination

6.4.1 Upon request, the operator of flares that are subject to Section 5.6 shall make available, to the APCO, the compliance determination records that demonstrate compliance with the provisions of 40 CFR 60.18, (c)(3) through (c)(5).

6.4.2 The operator of ground-level enclosed flares shall conduct source testing at least once every 12 months to demonstrate compliance with Section 5.7. The operator shall submit a copy of the testing protocol to the APCO at least 30 days in advance of the scheduled testing. The operator shall submit the source test results not later than 45 days after completion of the source testing.
6.5 Flare Minimization Plan

6.5.1 By July 1, 2010, the operator of a petroleum refinery flare or any flare that has a flaring capacity of greater than or equal to 5.0 MMBtu per hour shall submit a flare minimization plan (FMP) to the APCO for approval. The FMP shall include, but not be limited to:

6.5.1.1 A description and technical specifications for each flare and associated knock-out pots, surge drums, water seals and flare gas recovery systems.

6.5.1.2 Detailed process flow diagrams of all upstream equipment and process units venting to each flare, identifying the type and location of all control equipment.

6.5.1.3 A description of equipment, processes, or procedures the operator plans to install or implement to eliminate or minimize flaring and planned date of installation or implementation.

6.5.1.4 An evaluation of prevention measures to reduce flaring that has occurred or may be expected to occur during planned major maintenance activities, including startup and shutdown.

6.5.1.5 An evaluation of preventative measures to reduce flaring that may be expected to occur due to issues of gas quantity and quality. The evaluation shall include an audit of the vent gas recovery capacity of each flare system, the storage capacity available 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 shall determine the feasibility of reducing flaring through the recovery, treatment and use of the gas or other means.

6.5.1.6 An evaluation of preventative measures to reduce flaring caused by the recurrent failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner. The evaluation shall determine the adequacy of existing maintenance schedules and protocols for such equipment. For purposes of this section, a failure is recurrent if it occurs more than twice during any five year period as a result of the same cause as identified in accordance with Section 6.2.2.

6.5.1.7 Any other information requested by the APCO as necessary for determination of compliance with applicable provisions of this rule.
6.5.2 Every five years after the initial FMP submittal, the operator shall submit an updated FMP for each flare to the APCO for approval. The current FMP shall remain in effect until the updated FMP is approved by the APCO. If the operator fails to submit an updated FMP as required by this section, the existing FMP shall no longer be considered an approved plan.

6.5.3 An updated FMP shall be submitted by the operator pursuant to Section 6.5 addressing new or modified equipment, prior to installing the equipment. Updated FMP submittals are only required if:

6.5.3.1 The equipment change would require an authority to construct (ATC) and would impact the emissions from the flare, and

6.5.3.2 The ATC is deemed complete after June 18, 2009, and

6.5.3.3 The modification is not solely the removal or decommissioning of equipment that is listed in the FMP, and has no associated increase in flare emissions.

6.5.4 When submitting the initial FMP, or updated FMP, the operator shall designate as confidential any information claimed to be exempt from public disclosure under the California Public Records Act, Government Code Section 6250 et seq. If a document is submitted that contains information designated confidential, the operator shall provide a justification for this designation and shall submit a separate copy of the document with the information designated confidential redacted.

6.6 Vent Gas Composition Monitoring

Effective on and after July 1, 2011, the operator of a petroleum refinery flare or any flare that has a flaring capacity equal to or greater than 50 MMBtu per hour shall monitor vent gas composition using one of the five methods pursuant to Section 6.6.1 through Section 6.6.5 as appropriate.

6.6.1 Sampling that meets the following requirements:

6.6.1.1 If the flow rate of vent gas flared in any consecutive 15-minute period continuously exceeds 330 standard cubic feet per minute (SCFM), a sample shall be taken within 15 minutes. The sampling frequency thereafter shall be one sample every three hours and shall continue until the flow rate of vent gas flared in any consecutive 15-minute period is continuously 330 SCFM or less. In no case shall a sample be required more frequently than once every 3 hours.
6.6.1.2 Samples shall be analyzed pursuant to Section 6.3.4.

6.6.2 Integrated sampling that meets the following requirements:

6.6.2.1 If the flow rate of vent gas flared in any consecutive 15 minute period continuously exceeds 330 SCFM, integrated sampling shall begin within 15 minutes and shall continue until the flow rate of vent gas flared in any consecutive 15 minute period is continuously 330 SCFM or less.

6.6.2.2 Integrated sampling shall consist of a minimum of one aliquot for each 15-minute period until the sample container is full. If sampling is still required pursuant to Section 6.6.2.1, a new sample container shall be placed in service within one hour after the previous sample was filled. A sample container shall not be used for a sampling period that exceeds 24 hours.

6.6.2.3 Samples shall be analyzed pursuant to Section 6.3.4.

6.6.3 Continuous analyzers that meet the following requirements:

6.6.3.1 The analyzers shall continuously monitor for total hydrocarbon methane, and depending upon the analytical method used pursuant to Section 6.3.4, hydrogen sulfide or total reduced sulfur.

6.6.3.2 The hydrocarbon analyzer shall have a full-scale range of 100% total hydrocarbon.

6.6.3.3 Each analyzer shall be maintained to be accurate to within 20% when compared to any field accuracy tests or to within 5% of full scale.

6.6.4 Continuous analyzers employing gas chromatography that meet the following requirements:

6.6.4.1 The gas chromatography system shall monitor for total hydrocarbon, methane, and hydrogen sulfide.

6.6.4.2 The gas chromatography system shall be maintained to be accurate within 5% of full scale.

6.6.5 Monitor sulfur content using a colorimetric tube system on a daily basis, and monitor vent gas hydrocarbon on a weekly basis by collecting samples and having them tested pursuant to a method in Section 6.3.4.
6.6.6 If flares share a common header, a sample from the header will be deemed representative of vent gas composition for all flares served by the header.

6.6.7 The operator shall provide the APCO with access to the monitoring system to collect vent gas samples to verify the analysis required by Section 5.11.

6.7 Pilot and Purge Gas Monitoring

Effective on and after July 1, 2011, the operator of a petroleum refinery flare or any flare that has a flaring capacity equal to or greater than 50 MMBtu per hour shall monitor the volumetric flows of purge and pilot gases with flow measuring devices or other parameters as specified on the Permit to Operate so that volumetric flows of pilot and purge gas may be calculated based on pilot design and the parameters monitored.

6.8 Water Seal Monitoring

Effective on and after July 1, 2011, the operator of a petroleum refinery flare or any flare that has a flaring capacity equal to or greater than 50 MMBtu per hour with a water seal shall monitor and record the water level and pressure of the water seal that services each flare daily or as specified on the Permit to Operate.

6.9 General Monitoring

Effective on and after July 1, 2011, the operator of a petroleum refinery flare or any flare that has a flaring capacity equal to or greater than 50 MMBtu per hour shall comply with the following, as applicable:

6.9.1 Periods of flare monitoring system inoperation greater than 24 continuous hours shall be reported by the following working day, followed by notification of resumption of monitoring. Periods of inoperation of monitoring equipment shall not exceed 14 days per any 18-consecutive-month period. Periods of flare monitoring system inoperation do not include the periods when the system feeding the flare is not operating.

6.9.2 During periods of inoperation of continuous analyzers or auto-samplers installed pursuant to Section 6.6, operators responsible for monitoring shall take one sample within 30 minutes of the commencement of flaring, from the flare header or from an alternate location at which samples are representative of vent gas composition and have samples analyzed pursuant to Section 6.3.4. During periods of inoperation of flow monitors required by Section 5.10, flow shall be calculated using good engineering practices.
6.9.3 Maintain and calibrate all required monitors and recording devices in accordance with the applicable manufacturer’s specifications. In order to claim that a manufacturer’s specification is not applicable, the person responsible for emissions must have, and follow, a written maintenance policy that was developed for the device in question. The written policy must explain and justify the difference between the written procedure and the manufacturer’s procedure.

6.9.4 All in-line continuous analyzer and flow monitoring data must be continuously recorded by an electronic data acquisition system capable of one-minute averages. Flow monitoring data shall be recorded as one-minute averages.

6.10 Video Monitoring

Effective on and after July 1, 2011, the operator of a petroleum refinery flare shall install and maintain equipment that records a real-time digital image of the flare and flame at a frame rate of no less than one frame per minute. The recorded image of the flare shall be of sufficient size, contrast, and resolution to be readily apparent in the overall image or frame. The image shall include an embedded date and time stamp. The equipment shall archive the images for each 24-hour period. In lieu of video monitoring the operator may use an alternative monitoring method that provides data to verify date, time, vent gas flow, and duration of flaring events.

7.0 Compliance Schedule

Operators of flares, that are exempt under Section 4.0 and that lose exemption status, shall not operate flares until in full compliance with all applicable requirements of this rule effective on the date the exemption status is lost.
I. SUMMARY

A. Reasons for Rule Development and Implementation

The California Air Resources Board (ARB) and United States Environmental Protection Agency (EPA) classified the San Joaquin Valley Air Basin (SJVAB) as severe and serious non-attainment area for the state and federal ozone standards, respectively. In accordance with Federal Clean Air Act (CAA) requirements for non-attainment areas, the San Joaquin Valley Unified Air Pollution Control District (District) adopted the 2007 Ozone Plan to establish the strategy for attaining the federal eight-hour ozone standard. The SJVAB is also currently designated as nonattainment for the national ambient air quality standard (NAAQS) for particulate matter with aerodynamic diameter of 2.5 micrometers or less (PM2.5). As such, the District’s Governing Board adopted the 2008 PM 2.5 Plan on April 30, 2008.

The ozone and particulate matter attainment strategies are comprised of regulatory and incentive-based measures to reduce emissions of oxides of nitrogen (NOx), volatile organic compounds (VOC), particulate matter and sulfur oxides (SOx). As a result, this rule development project is subject to the Code of Federal Regulations (CFR), the CAA and the California Health and Safety Code (CH&SC) requirements.

This rule amending project is proposed to satisfy the goals of the District’s 2007 Ozone Plan and 2008 PM2.5 Plan. The draft amendments to Rule 4311 will seek to obtain as much NOx, SOx, PM, and VOC emission reductions from the source category as expeditiously practicable, technologically feasible, and
economically reasonable, as determined by the District’s Governing Board. Furthermore, the District intends to satisfy the requirements identified in Table 1.

<table>
<thead>
<tr>
<th>Subject</th>
<th>Reference</th>
<th>Requirement</th>
</tr>
</thead>
<tbody>
<tr>
<td>BACM</td>
<td>Federal Register 8/18/94</td>
<td>Provisions in attainment plans should include the application of best available control measures (BACM) to existing major stationary sources.</td>
</tr>
<tr>
<td>BARCT</td>
<td>CH&amp;SC 40919(a)(3) 2007 Ozone Plan</td>
<td>Ozone attainment plan should provide for best available retrofit technology (BARCT) for existing permitted sources.</td>
</tr>
<tr>
<td>Deadlines</td>
<td>Ozone Plan</td>
<td>Adoption of rule amendments by the 2nd quarter of 2009.</td>
</tr>
<tr>
<td>Feasible Controls</td>
<td>CH&amp;SC 40914(a)(2)</td>
<td>Ozone attainment plans should include &quot;all feasible control measures.&quot;</td>
</tr>
<tr>
<td>RACT</td>
<td>CAA 182(b)(2) and 182(f)</td>
<td>Ozone attainment plans shall assure that reasonable available control technology (RACT) for oxides of nitrogen (NOx) and VOC is in use at sources and on source categories at or above the RACT threshold.</td>
</tr>
<tr>
<td>RACT Threshold</td>
<td>70 Federal Register 30592-30596 5/26/05</td>
<td>The applicable RACT threshold for control measures shall be the threshold in effect on June 15, 2004. The Districts threshold on June 15, 2004 was 10 tons per year (tpy) for NOx or VOC.</td>
</tr>
<tr>
<td>Reductions</td>
<td>Ozone Plan and PM 2.5 Plan</td>
<td>Emissions reduction will be calculated during the rule development process.</td>
</tr>
<tr>
<td>Timeline</td>
<td>CAA Section 172(c)(1)</td>
<td>Ozone attainment plans shall implement control measures as expeditiously as practicable, and provide for attainment.</td>
</tr>
</tbody>
</table>

B. Climate Change

The California Global Warming Solutions Act of 2006 (AB 32) created a comprehensive, multi-year program to reduce greenhouse gas (GHG) emissions in California, with the goal of restoring emissions to 1990 levels by 2020. In the coming years, ARB and the Legislature will be developing policies and programs to implement AB 32. There are many win-win strategies that can reduce both GHG and criteria/toxic pollutant emissions. However, when situations that involve tradeoffs between GHG and criteria or toxic pollutants arise, District staff
will give precedence to criteria or toxic pollutant emissions due to the more immediate public health concerns associated with such pollutants.

C. Description of Project

This rule project would amend Rule 4311 (Flares) to implement emission control requirements in the 2007 Ozone Plan as well as the 2008 PM 2.5 Plan. The changes being considered are contained in flare rules or permit conditions in other air districts in California, such requirements would be considered for inclusion to ensure that Rule 4311 meets federal RACT and BACM requirements as well as CH&SC requirements to implement BARCT and all feasible control measures.

In developing the draft amendments to Rule 4311, District staff evaluated the emission reduction potential of flare minimization plans (FMP) and other provisions that other air districts' rules have already implemented, and determined that it is feasible to require similar emission controls for flares that are operating within the District. However, other relevant findings, available technical information, and input from stakeholders were considered during the rule development process in order to further refine the draft rule amendments.

D. Rule Development Process

As part of the rule development process, District staff conducted a public scoping meeting in April 2008. Three public workshops have been held: August 2008, January 2009, and March 2009. A socioeconomic focus group was also conducted in January 2009 and March 2009. At the public meetings, District staff presented the objectives of the proposed rulemaking project, the draft amended rules, draft staff reports, explained the District’s rule development process, solicited suggestions from affected stakeholders, and informed all interested parties about tentative upcoming workshop dates, comment periods, and project milestones.

The knowledge gathered during the scoping meeting and public workshops was used to help with amending the draft rule and draft staff report. Each new draft rule and draft staff report was then presented to the public through public workshops. Each workshop was followed by a two week public comment period. Comments received during the public workshop process were incorporated in the amended draft rule as appropriate.

The final draft rule, draft staff report, and socioeconomic analysis report will be published prior to the public hearing to consider the adoption of the amendments to the rule by the District's Governing Board. The District's 2007 Ozone Plan committed to schedule the public hearing to consider the adoption of the amended rule in the second quarter of 2009.
II. BACKGROUND

The EPA, per 40 CFR 52.65284, recommends the District “reconsider the utility of incorporating provisions such as those in South Coast Air Quality Management District (SCAQMD) Rule 1118 and Bay Area Air Quality Management District (BAAQMD) Rule 12-12 within Rule 4311 to aid their enforcing of the rule, developing an accurate emissions inventory for theses sources, and minimizing excess emissions from flare activity to the maximum extent practicable.” The experience of the Bay Area Air Quality Management District (AQMD) and South Coast AQMD in incorporating FMPs have resulted in data being gathered, which can be used to evaluate the effectiveness of FMPs in reducing flaring events.

Flaring is a high temperature oxidation process used to burn combustible components, mostly hydrocarbons, of waste gases from industrial operations. 95 percent of the waste gases flared are natural gas, propane, ethylene, propylene, butadiene and butane. During combustion, gaseous hydrocarbons react with atmospheric oxygen to form carbon dioxide (CO$_2$) and water. In some waste gases, carbon monoxide (CO) is the major combustible component.

Flares generate air pollutants such as oxides of nitrogen, sulfur dioxide, carbon monoxide, and particulate matter. Additionally, there is a possibility of release of hydrocarbons that have not been completely combusted.

General Equipment Description

There are two general types of flares, elevated and ground flares. Flares are categorized by the height of the flare tip, and by the method of enhancing combustion by mixing at the flare tip (i.e., steam-assisted, air-assisted, pressure-assisted, or non-assisted).

Elevated flares are more common and have larger capacities than ground flares. In elevated flares, a waste gas stream is fed through a stack, which can be over 100 meters tall and is combusted at the tip of the stack. An elevated flare consists of five components: a gas collection header (to collect gases from various process units), a proprietary seal, water seal, or purge gas supply (to prevent flash back), a single or multiple-burner unit in the flare stack, and gas pilots and igniter.

Ground flares vary in complexity and can consist of either conventional flare burners discharging horizontally with no enclosures or of multiple burners in refractory-lined steel enclosures.
Complete combustion requires proper mixing of air and waste gas. Smoking may result from incomplete combustion, depending upon the waste gas components and the quantity and distribution of combustion air. Waste gases containing methane, hydrogen, CO, and ammonia usually burn without smoke, while waste gases containing heavy hydrocarbons cause smoke.

An external momentum force, such as steam injection, is used for efficient mixing of air and waste gas, and turbulence, which promotes smokeless flaring of heavy hydrocarbon waste. Other external forces may also be used, including water spray, high velocity vortex action, or natural gas. External momentum force is rarely required in ground flares. Combustion efficiency depends on flame temperature, residence time in the combustion zone, vent gas flammability, auto ignition temperature, heating value in British thermal units per standard cubic feet (Btu/scf), and turbulent mixing. These factors promote a destruction efficiency of 98 percent or greater. Complete combustion would convert all VOCs to carbon dioxide and water.

Figure 1. Industrial Flare
Waste gases must have a fuel value of at least 200 to 250 British thermal units per cubic foot (btu/ft$^3$) for complete flare combustion. If a waste gas does not have the required fuel value, then fuel must be added. Flares providing supplemental fuel to waste gas are known as fired, or endothermic, flares. In some cases, even flaring waste gases having the necessary heat content will also require supplemental heat.

Flares are normally used to dispose of low volume continuous emissions, but are designed to handle large quantities of waste gases associated with plant emergencies. Flare gas volumes can vary from a few cubic meters per hour during regular operations up to several thousand cubic meters per hour during major upsets.

III. DISCUSSION

SJVAPCD Rule 4311 (Flares) would be unique from all other flare rules in California in that it applies to all flares with the exception of municipal landfill flares. This source category currently includes flares associated with oil and gas production, combustion, sewage treatment, incinerators, petroleum refining, and VOC control. Other air districts in California with flare rules apply those flare rules to a limited number of sources. For example, the SCAQMD Rule 1113 (Emissions from Refinery Flares) and BAAQMD Rules 12-11 (Flare Monitoring at Petroleum Refineries) and 12-12 (Flares at Petroleum Refineries) only apply to petroleum refining flares. The Santa Barbara APCD flare rule, Rule 359 (Flares and Thermal Oxidizers), applies to the use of flares and thermal oxidizers at oil and gas production sources, petroleum refiners, natural gas services and transportation sources, and wholesale trade in petroleum. The Ventura County APCD rule, Rule 54 (Sulfur Compounds) is not a flare rule but a sulfur compound rule which prohibits the discharge of sulfur compounds from any source, including flares, exceeding specified concentrations. All the aforementioned flare rules require submittal of a flare minimization plan.

A search of the District’s permits data base indicates that facilities from 16 different SIC codes are required to comply with Rule 4311 and will be affected by changes to the rule language. The diversity of industries that must comply with Rule 4311 is illustrated in Table 2.
Table 2. SIC Codes and Corresponding Industries

<table>
<thead>
<tr>
<th>SIC</th>
<th>SIC Industry</th>
</tr>
</thead>
<tbody>
<tr>
<td>241</td>
<td>Dairy Farms</td>
</tr>
<tr>
<td>1311</td>
<td>Crude Petroleum and Natural Gas</td>
</tr>
<tr>
<td>1321</td>
<td>Natural Gas Liquids</td>
</tr>
<tr>
<td>1389</td>
<td>Oil and Gas Field Services, Not Elsewhere Classified</td>
</tr>
<tr>
<td>2037</td>
<td>Frozen Fruits, Fruit Juices, and Vegetables</td>
</tr>
<tr>
<td>2869</td>
<td>Industrial Organic Chemicals, Not Elsewhere Classified</td>
</tr>
<tr>
<td>2879</td>
<td>Pesticides and Agricultural Chemicals, Not Elsewhere Classified</td>
</tr>
<tr>
<td>2911</td>
<td>Petroleum Refining</td>
</tr>
<tr>
<td>3211</td>
<td>Flat Glass</td>
</tr>
<tr>
<td>4612</td>
<td>Crude Petroleum Pipelines</td>
</tr>
<tr>
<td>4922</td>
<td>Natural Gas Transmission</td>
</tr>
<tr>
<td>4952</td>
<td>Sewerage Systems</td>
</tr>
<tr>
<td>4959</td>
<td>Sanitary Services, Not Elsewhere Classified</td>
</tr>
<tr>
<td>5172</td>
<td>Petroleum and Petroleum Products Wholesalers, Except Bulk Stations and Terminals</td>
</tr>
<tr>
<td>9199</td>
<td>General Government, Not Elsewhere Classified</td>
</tr>
<tr>
<td>9223</td>
<td>Correctional Institutions</td>
</tr>
</tbody>
</table>

Another difference between the SJVAB flares and the SCAQMD and BAAQMD flares is the quantity and the emissions from those flares. This difference is best illustrated by a comparison between the quantity of flares that would be affected by the rule and amendments to it. Currently there are about 137 flares in the SJVAPCD that are affected by Rule 4311, from an estimated 87 facilities. Whereas the SCAQMD has 27 flares and the BAAQMD has 17 flares affected by their respective flare rules. The SJVAPCD had 75.8 tpy of VOC emissions, whereas the SCAQMD had an estimated 2,713 tpy. The only emission information available from the BAAQMD included emissions data for sulfur, but NOx inventory was been requested, but not received at the time this report was prepared.

It is important to note that the emissions inventory for the SCAQMD and BAAQMD are from 2006 and 2008 respectively, the data was taken from the district web sites. The emissions data from those districts is after the implementation of FMP and monitoring and reporting requirements, whereas the SJVAPCD emission inventory is pre-FMP.
When comparing the South Coast and Bay Area with the San Joaquin Valley, the difference in emissions of SO$_2$ is extremely higher. Even though the SJVAB has five times as many flares as the South Coast, the South Coast SO$_2$ emissions are 3.5 times as large as the SJVAB. Similarly, even though the SJVAB has 7 times as many flares as the Bay Area, the Bay Area SO$_2$ emissions are 5.7 times as large as in the SJVAB. A more detailed discussion of the SCAQMD and BAAQMD flare rules is provided in Section III A of this draft staff report.

Table 3 provides a comparison of the number of refineries and other sources covered by the flare rules of the SJVAPCD, SCAQMD, and BAAQMD. It is important to note that while the number of the refineries in the three regions is approximately equal, the production capacities, and therefore the relative emissions of the SJVAB refineries is significantly lower than the other regions. This was an important consideration when determining appropriate monitoring and reporting requirements.

Table 3. Comparison of SJVAPCD, SCAQMD, and BAAQMD Flare Emissions

<table>
<thead>
<tr>
<th>Facilities affected by Flare Rule</th>
<th>SJVAPCD</th>
<th>SCAQMD$^1$</th>
<th>BAAQMD$^1$</th>
</tr>
</thead>
<tbody>
<tr>
<td>Non-petroleum refining flares</td>
<td>130</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Petroleum Refiner Flares</td>
<td>7</td>
<td>27</td>
<td>17</td>
</tr>
<tr>
<td>Petroleum Refining Facilities</td>
<td>5</td>
<td>7</td>
<td>5</td>
</tr>
<tr>
<td>2008 Total Annual Petroleum Refinery Production Capacity (MMBBL)</td>
<td>39.06</td>
<td>397.33</td>
<td>286.34</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Criteria Pollutant$^2$</th>
<th>Emissions (tpy)</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>SOx</td>
<td>66</td>
<td>235</td>
</tr>
<tr>
<td>NOx</td>
<td>146</td>
<td>135</td>
</tr>
<tr>
<td>ROG</td>
<td>76</td>
<td>94</td>
</tr>
<tr>
<td>PM</td>
<td>21</td>
<td>31</td>
</tr>
<tr>
<td>CO</td>
<td>276</td>
<td>459</td>
</tr>
</tbody>
</table>

1. Data presented is recent available from SCAMQD and BAAQMD websites.
2. Criteria Pollutant information presented for SJVAPCD is a combination of the 137 refining and non-refining flares that will be affected by this rule.
IV. CURRENT AND PROPOSED REGULATIONS

Federal Requirements
The EPA has promulgated standards for SO\textsubscript{2} emissions, in addition to establishing requirements for performance testing and compliance assessments, for flares at petroleum refineries.

The new source performance standards (NSPS) for refinery flares constructed or modified after June 11, 1973 are covered under 40 CFR Part 60, Subparts A and J. Subpart A applies to flares as general control devices, specifying design and operational criteria for new and modified flares. Requirements include operating the flare with no visible emission, monitoring the presence of the pilot flame with a thermocouple or equivalent device, and meeting heat content and maximum tip exit velocity specifications. Subpart J applies to flares at petroleum refineries, where flares are defined as fuel gas combustion devices, and are limited to burning fuel gas, for the maintenance of the pilot flame, containing hydrogen sulfide (H\textsubscript{2}S) in excess of 0.10 gr/dscf. This limitation does not apply during process upsets, relief valve leakage, or other emergency malfunctions, where vent gases or fuel gas are released to the flare. This subpart also requires that a continuous monitoring and recording device be installed to track emissions of SO\textsubscript{2} or H\textsubscript{2}S from the flare, in addition to the installation of an oxygen monitor for correcting the emissions data for excess air.

The national emission standards for hazardous air pollutants (NESHAP) for flares are covered in 40 CFR part 63, Subpart SS, which applied to closed vent systems, control devices, recovery devices and routing to a fuel gas system or process. Under the flare requirements of this subpart, flares are subject to compliance assessment and monitoring requirements. Compliance assessments include using EPA’s Method 22 to determine measure opacity, using Equation 1 (of 40 CFR Part 63, Subpart SS) to determine the net heating value of the gas being combusted, using EPA Method 2, 2A, 2C, 2D, 2F, or 2G of 40 CFR Part 60 Appendix A to measure the volumetric flow rate, and using flame or pilot monitors during compliance assessments. Flare monitoring requirements indicate that a device (e.g., thermocouple, ultra-violet beam sensor, or infrared sensor) to detect the presence of the flare flame must be used at all times when the flare is in use.

Bay Area Air Quality Management District (BAAQMD)
On June 4, 2003, BAAQMD adopted Rule 12-11 (Flare Monitoring at Petroleum Refineries) requiring monitoring and recording of emissions data for flares at petroleum refineries. This rule enabled BAAQMD to collect emissions data from refineries, which BAAQMD used to determine the causes of specific flaring events, as well as estimate the quantity of emissions released during those events. As a result of findings obtained under Rule 12-11, Rule 12-12 (Flares at Petroleum Refineries) was adopted July 20, 2005.
Rule 12-12 reduces emissions from flares by minimizing the frequency and magnitude of flaring. Rule 12-12 also prohibits the use of refinery flares without the refinery first creating, following, and annually updating an FMP for each flare. Facilities are required to submit flaring reports when a flare releases more than 500,000 standard cubic feet of gas per calendar day (scf/day). The flaring report must identify the cause explain actions that will be taken to avoid flaring from that cause in the future, if possible. The rule also requires continuous monitoring of the flare system’s knock-out drum water seal for leaks, and the submittal of annual reports to BAAQMD that evaluate flaring events that released less than 500,000 scf/day, but SO₂ emitted was more than 500 lbs.

FMPs have proven successful in the BAAQMD in reducing flare emissions. The following chart was taken from the 2008 status report on the Flare Minimization Plan Annual Update presented to the Stationary Source Committee by BAAQMD Staff on September 8, 2008. The chart illustrates the trend in refinery flare emissions since the adoption of the BAAQMD flare rules. Note that the adoption date of Rule 12-11 requiring flare monitoring was adopted in 2003 and Rule 12-12 requiring flare minimization plans was adopted in 2005.

Chart 1. BAAQMD Refinery Flare Trends
South Coast Air Quality Management District (SCAQMD)

SCAQMD adopted Rule 1118 (Emissions from Refinery Flares) in February of 1998. The emissions data collected as a result of Rule 1118, between 1999 and 2003, was analyzed and resulted in recommendations for further strengthening emissions monitoring and reporting procedures, leading to the adoption of amendments on November 4, 2005.

The 2005 amendments prohibit the flaring of vent gases except in emergency situations, or during specific operational needs such as startups, shutdowns, and turnarounds. Operational requirements were established and practices put in place to minimize flaring events, set specific annual SO$_2$ performance targets, require flares to operate in a smokeless manner, and require annual inspections of pressure relief devices directly connected to flares. If a refinery does not meet SO$_2$ performance targets, then that facility is required to have a FMP.

The rule also contains provisions for refineries to give 24-hour advance notice for each large planned flaring activity, as well as to notify SCAQMD within 1-hour of unexpected flaring events. Also required is the submittal of quarterly reports detailing flow, emissions, and cause of each flaring event. SCAQMD also requires refineries to set up a 24-hour public telephone number for inquiries on flaring events. Table 4 illustrates the annual flare emissions reported to the SCAQMD during the years of 2000 through 2004. This table was copied from the SCAQMD website.

<table>
<thead>
<tr>
<th>Year</th>
<th>Flow(scf)</th>
<th>NOx</th>
<th>VOC</th>
<th>CO</th>
<th>PM10</th>
<th>SOx</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>2000</td>
<td>4,085,000,000</td>
<td>136</td>
<td>125</td>
<td>733</td>
<td>43</td>
<td>2,633</td>
<td>3,670</td>
</tr>
<tr>
<td>2001</td>
<td>8,324,000,000</td>
<td>380</td>
<td>456</td>
<td>2,058</td>
<td>87</td>
<td>1,793</td>
<td>4,774</td>
</tr>
<tr>
<td>2002</td>
<td>2,440,000,000</td>
<td>83</td>
<td>78</td>
<td>450</td>
<td>25</td>
<td>754</td>
<td>1,390</td>
</tr>
<tr>
<td>2003</td>
<td>2,235,000,000</td>
<td>79</td>
<td>75</td>
<td>423</td>
<td>23</td>
<td>735</td>
<td>1,335</td>
</tr>
<tr>
<td>2004</td>
<td>2,392,000,000</td>
<td>93</td>
<td>70</td>
<td>364</td>
<td>27</td>
<td>352</td>
<td>906</td>
</tr>
</tbody>
</table>

Ventura County Air Pollution Control District (VCAPCD)

Rule 54 (Sulfur Compounds) was adopted July 2, 1968, and last amended June 14, 1994. Rule 54 prohibits the discharge of sulfur compounds from any source, including flares, exceeding specified concentrations. Rule 54 not only applies to refinery flares but to non-refinery petroleum operations as well.

VCAPCD Rule 54 specifies that no person shall discharge sulfur compounds which would exist as a liquid or gas at standard conditions, in excess of the specified concentrations. Rule language also specifies several scenarios that are exempt from rule requirements including unplanned flaring, and planned flaring provided certain circumstances are met.
Unplanned flaring is exempt from rule requirements as long as the unplanned burning of gas is for emergency or safety concerns provided all the following conditions have been met a) the flaring is not the result of an intentional or negligent act or omission on the part of the operator or owner, b) The flaring is not the result of improper maintenance or improper setting of specific sensors, c) the flaring event results from operational problems, including but not limited to: emergency blowdowns, process upsets, power outages, and equipment breakdown, d) records or logs of each flaring event shall be kept, e) the owner or operator immediately undertakes appropriate corrective measures, f) the unplanned flaring event shall not exceed 24 hours in duration and g) sulfur emissions are minimized.

Planned Flaring Events are exempt from rule requirements provided that a) a notice to flare has been submitted in writing at least 72 hours prior to such work being done, which justifies that such work shall be done, b) each operator shall have a planned flaring management plan, c) records of the date, time, duration, flare volume and estimated sulfur emissions (as pounds of SO\(_2\)) are kept during the entire flaring event, d) the District is notified in writing when work is completed e) sulfur emissions are minimized during the operation, and f) no flaring shall occur unless an excess emission fee of $5.00 per pound of sulfur compounds emitted is paid to the District each calendar year.

Each operator is required to submit a Flaring Management Plan to the District which includes descriptions of all measures to be implemented to decrease flare gas volume and reduce sulfur emissions, all planned operational or maintenance procedures that may cause flaring, design features of each flare system, all measures to be implemented to reduce the number of planned flaring vents including changes to maintenance or production schedules or installation of new procedures or equipment and any other information determined by the APCO to be necessary for evaluating the qualifications of a source for this exemption.

**Santa Barbara County Air Pollution Control District (SBCAPCD)**

SBCAPCD adopted Rule 359 (Flares and Thermal Oxidizers) on June 28, 1984. Provisions of this rule apply to the use of flares and thermal oxidizers at oil and gas production sources (SIC code 13), petroleum refinery and related sources (SIC code 29), natural gas services and transportation sources (SIC code 49) and wholesale trade in petroleum/petroleum products (SIC code 51). For purposes of this staff report thermal oxidizer portions of that rule will not be discussed as it does not apply to this rule amending project.

Rule 359 sets specific requirements for the sulfur content in gaseous fuels, technology based standards, flare minimization plans, emergency events, and emission and operational limits.
Rule language includes Technology-Based Standards, that specify all flares shall be smokeless, the outlet shall be equipped with an automatic ignition system or shall operate with a pilot flame present at all times, the presence of the flame in the pilot of the flare shall be continuously monitored using a thermocouple or an equivalent device that detects the presence of a flame, and the flame shall be operating at all times when combustible gases are vented through the flare.

A FMP shall be submitted by any source subject to this rule that operates a flare rated at 15 MMBtu/hour or greater. For planned flaring, the minimization plan for all sources subject to this rule shall list a targeted maximum monthly flared gas volume, which shall not exceed five percent of the average monthly gas handled/produced/treated at the source. Where limits have been established for sources the owner or operator shall develop and submit an emissions mitigation plan, which shall achieve a reduction by 50 percent, of either the actual average monthly flare gas volume or the proposed volume limit, whichever reduction volume is greater.

Any flaring which causes an exceedance of the emission limits or standards of this rule shall not be a violation of this rule if the owner or operator of the source demonstrates that the exceedance resulted from an emergency event. To demonstrate that an emergency even occurred, the owner or operator shall follow specific guidelines stated in rule language.

Emission and operational limits shall apply to any source subject to the Rule and include the following: a) flares which use flow-sensing automatic ignition systems and which do not use a continuous flame pilot shall use inert gas or PUC quality gas for purging, b) flares with a rating of 15 million Btu/hour or greater shall not exceed, for planned flaring, the targeted monthly volume limit of flare gas established pursuant to the FMP, and c) pollutant emissions from all thermal oxidizers and ground-level enclosed flares with planned continuous flaring exceeding 120,000 scf/day shall meet the emission standards presented in rule language.

Rule 359 does not apply to the burning of sulfur, hydrogen sulfide, acid sludge or other sulfur compounds in the manufacturing of sulfur or sulfur compounds. For oil and gas sources (SIC code 13) that recover sulfur as a by-product of gas treating/sweetening processes, the exemption for manufacturing shall apply only to those specific processes, e.g., sulfur recovery plant. The provisions of the rule, with the exception of Technology Standards, shall not apply to the burning of any gas with a net heating value of less than 300 Btu/scf provided the fuel used to incinerate such gas does not contain sulfur compounds in excess of the following 15 grains/100cu.ft. in the Southern Zone, and 50 grains/100cu.ft. in the Northern Zone of Santa Barbara County.
Flare units rated at less than 15 MMBtu/hr, unless the total cumulative rating of all such rated units at a source exceeds 50 MMBtu/hr and flares whose flaring operations solely consist of planned, continuous flaring due to the non-availability of a produced gas pipeline outlet are exempt from FMP requirements.

San Joaquin Valley Air Pollution Control District (SJVAPCD)
District Rule 4311 (Flares) applies to operations involving the use of flares with the exemption of flares operated in municipal solid waste landfills, flares that are subject to the requirements of 40 CFR 60 Subpart WWW (Standards of Performance for Municipal Waste Landfills), and flares subject to 40 CFR 60 Subpart Cc (Emission Guidelines and Compliance Times for Municipal Solid Waste Landfills).

District Rule 4311 currently has four main requirements:

- Technology – based standards listed to confirm with EPA requirements.
- Emission limits for ground–level, enclosed flares.
- The compliance determination and source testing for ground – level enclosed flares.
- Record keeping requirements for flares used during an emergency, records are to be retained documenting the duration of flare operation, amount of gas burned, and nature of an emergency situation, and are to be submitted to the APCO upon request.

B. Revised Proposed Draft Amendments

District staff is proposing to add monitoring, reporting requirements and flare minimization plans to the current flare rule in order to reduce flare emissions in the SJVAB. FMPs in other districts, namely the South Coast and Bay Area have been shown to reduce flare emissions by minimizing the frequency and magnitude of flaring. As such, District staff believes that implementing FMP requirements will reduce emissions from flares in the SJVAB.

Draft rule language has been reformatted in response to concerns that the previous formatting may have caused confusion. By reformatting rule language, the rule language is more in line with other prohibitory rules at the SJVAPCD. The following is a summary of the major proposed draft amendments to Rule 4311.

**Section 1.0 Purpose**
Sulfur Oxides will be added to the emissions to be reduced from flaring activities.

**Section 2.0 Applicability**
No changes are proposed for Section 2.0 at this time.
Section 3.0 Definitions
Definitions would be added or amended to provide clarity and to reflect the additions of flare monitoring, flare reporting, and flare minimization plans to rule language.

Section 4.0 Exemptions
No changes are proposed for Section 4.0 at this time.

Section 5.0 Requirements

Section 5.8 Flare Minimization Requirements
A new requirement requiring flare minimization plans (FMP) effective on and after July 1, 2011 would be added to rule language. Petroleum refinery flares and flares with a flaring capacity at or greater than 5 MMBtu/hr will be subject to FMP requirements. A standard of 5 MMBtu/hr was determined appropriate because this has been an established District standard for permitting, as with District Boiler rules, and because of the low potential to emit from flares smaller than 5 MMBtu/hr compared to the potential to emit from large flares. A survey of the District permit database indicates the 5 MMBtu/hr threshold will capture about 75% of the flares in the SJVAB, representing 81% of NOx emissions from this source category.

Petroleum refiners will be subject to FMP requirements, regardless of the size of the flare, to ensure this rule is as stringent as other flare rule requirements in other districts in California.

Flaring at facilities subject to FMP requirements would be prohibited unless it is consistent with an approved FMP and all commitments due under that plan have been met. This standard shall not apply if the APCO determines, based on an analysis conducted in accordance with rule language, that the flaring was caused by an emergency, and was necessary to prevent an accident, hazard, or release of vent gas directly into the atmosphere.

District staff recognizes the difficulties of compliance with the submittal of FMPs for portable safety flares used during the drilling of crude oil and natural gas production wells. These types of flares are typically owned by rental companies and are relocated from well site to well site where they operate for time periods ranging from a few days to several months. Stakeholders expressed concern that the preparation and approval of updated FMP may possibly hinder the use of these portable safety flares. As FMPs are site specific, it could be unclear how a company would obtain District approval of a generic FMP authorizing the operation of flares at well site locations, since the locations are not likely to be known in advance. Therefore, the District will provide a template FMP for these portable emergency flares, as part of the rule implementation phase, similar to the multiple location permits that are currently issued for these flares.
Section 5.9 Petroleum Refinery Performance SO\textsubscript{2} Targets
A new section would be added to provide performance targets for emissions of sulfur, expressed as sulfur dioxide (SO\textsubscript{2}), from flares at petroleum refineries. The new standard would set an emission limits starting January 1, 2011, with a second, more stringent standard on January 1, 2017. This new standard was put in place to make District Rule 4311 as stringent as the flares rule in the South Coast Air Quality Management District. The SO\textsubscript{2} emissions target will mirror the SCAQMD emission target in that it will be based on the annual crude processing capacity of each petroleum refiner. The crude processing capacity will be based on information obtained from the Energy Information Association (EIA). Therefore, each petroleum refiner would have a SO\textsubscript{x} emission limit that is unique to that facility.

Research of the District permit database indicates that, based on current permits and report inventory, only one petroleum refinery will be affected by the new sulfur dioxide standard, and that refinery is already in compliance with the first of the two proposed performance standards. The SCAQMD rule set SO\textsubscript{2} standards to become more stringent and to go into effect every two years for eight years, until the most stringent standard of 0.50 tons per MMbbl of crude processing capacity was met.

Research of the District permit database and conversations with the staff from the petroleum refinery affected by this new standard indicated that the refinery was in compliance with the first standard, and they believed, the second standard as well. As a result of the research, conversations and in response to the economic hardships facing the valley, staff is proposing to apply the first standard on the original proposed date, to ensure refiners don’t increase SO\textsubscript{2} emissions and encourage them to work toward the next standard. The next standard proposed would be in 2017 with 0.50 tons per MMbbl of crude processing capacity, which is also the original standard and date for this, the most stringent standard. By implementing this approach, the District will achieve the same reductions in 2018 as we would if we were to mirror the SCAQMD implantation schedule, while remaining sensitive to the current economic times in the valley.

Section 5.10
This section would include language in the requirements section of the rule to specify that the operator of the flare shall monitor vent gas flow with a flow measuring device, or other parameters as specified in the Permit to Operate. This section is not providing a new requirement rather this is a clarification of rule standards. This section was recently revised to exclude flares that cannot trigger a reportable flaring event. Details of this change and the history of this section are provided below.
Facilities subject to FMP requirements are required to submit an annual report, pursuant to Section 6.2.2, that summarizes all reportable flaring events as defined in Section 3.0 that occurred during the previous twelve month period. A reportable flaring event, as defined by Section 3.31 is any flaring where more than 500,000 standard cubic feet of vent gas is flared per calendar day, or where sulfur oxide emissions are greater than 500 pounds per calendar day. In order to comply with the report in Section 6.2.2 it was implied that the operators would have to monitor vent gas flow, otherwise they would not know if the flare event was reportable or not.

This reportable flaring event requirement was numbered Section 6.4.5 in the first through third drafts of the rule. Through various revisions of the rule, this requirement is now Section 6.2.2. However, this reporting requirement has not changed since the first draft of the rule. Language similar to that in Section 5.10 was in previous drafts of the rule as Section 7.1. Section 7.1 was a Section of requirements for Flare Monitoring for petroleum refiners and flares with a flaring capacity equal to or greater than 50 MMBtu/hr. Upon review of rule language staff felt stakeholders subject to FMPs with flares smaller than 50 MMBtu/hr might misunderstand the rule to believe they would not have to monitor flare gas flow, and as a result would be out of compliance with the reporting requirements of Section 6.2.2. Therefore, to improve clarity and alleviate the possibility of accidental non-compliance staff removed the language in Section 7.1 and added language in Section 5.10.

District staff are aware that there are some flares that are subject to FMP requirements, meaning they are rated at and above 5 MMBtu/hr flaring capacity, but that cannot achieve the 500,000 scf or 500 pounds of sulfur oxide emissions per calendar day threshold for a reportable flaring event. The purpose of requiring flare vent gas flow monitoring, as stated above, is to comply with reporting requirements in Section 6.2.2. As it is unnecessary to monitor vent gas flow to prove compliance with Section 6.2.2 for flares that cannot achieve the threshold limits, a provision has been added to rule language stating that if an operator can prove, based on permit conditions that the flare cannot achieve the reportable flaring event threshold then the vent gas flow requirement of Section 5.10 shall not be required. This is not a relaxation of existing rule standards and is not a significant change due to it being an unnecessary monitoring requirement for those smaller flares that can not flare at levels that would trigger reportable flare event reports. This change will have no significant impact on rule requirements, emission reductions, or the Districts ability to enforce compliance of rule standards.
Section 5.11
This section would include language in the requirements section of the rule to specify that the operator of a petroleum refinery flare or a flare with a flaring capacity equal to or greater than 50 MMBtu/hr shall monitor the flare pursuant to Sections 6.6 thru 6.10. This section is not providing a new requirement, but clarifying that this is a requirement in this rule. This section was previously Section 7.0.

Section 6.0 Administrative Requirements
Section 6.0 has been reorganized to clarify the administrative rule standards.

Section 6.1 Recordkeeping
The former Section 6.1 Compliance Determination has not been changed, but rather it has been moved to Section 6.4 to pair it with Section 6.3 Test Methods. Recordkeeping has been moved from Section 6.2 to 6.1 and a new section, Section 6.2 Flare Reporting has been added to rule language.

Formerly Section 6.2, new Section 6.1 recordkeeping requirements would be added to incorporate monitoring data, annual reports, and FMPs. Operators would be required to maintain copies of FMPs, annual reports submitted to the APCO pursuant to Section 6 and Section 7, as applicable, and monitoring data collected pursuant to Section 7.0 as applicable, at the facility for a period of five years. The effective dates of recordkeeping requirements are set to align with compliance and FMP dates.

Section 6.2 Flare Reporting
A new section would be added to rule language to provide clarity to rule standards. The requirements in Section 6.2 are not new reporting requirements, but have been pulled from other sections of the rule and placed together to provide fluidity and clarity to rule language.

Section 6.2.1 Unplanned Flaring Event
This section was Section 6.4.4 in previous drafts of this rule. This section will require the operator to notify the APCO within 24 hours after the start of the next business day or within 24 hour of their discovery, which ever occurs first. The notification shall include the flare source identification, the start date and time, and the end date and time. This section has been modified from the previous versions in that the previous version of the draft rule required a notification within 24 hours of the start of the flare event. That reporting timeline has been amended to include 24 hours after the discovery or 24 hours after the start of the next business day, which ever occurs first. This change is not a significant change because it aligns this rule with other flare rules in other districts.
Petroleum refineries in the SCAQMD and BAAQMD are monitored at all times making it possible to provide the responsible district with notification within a very short time. However Rule 4311 applies to flares in several industries, and many flares within the valley are unmanned flares located at remote locations, making immediate notification to the district infeasible.

Unlike police or fire fighters, the District is not a first responder in an emergency situation so immediate notification is not essential. During an emergency situation, it is more vital for the operator to be concerned about controlling the situation than satisfying a reporting requirement. Further, the rule provides up to 24 hours for reporting but in normal circumstances, the event would be reported well before the deadline. The proposed reporting of an unplanned flare event within 24 hours does not affect compliance, enforcement, or the District's ability to collect data regarding flare events. This is not a significant change because it better aligns requirements with those of SCAQMD and BAAQMD.

Section 6.2.2 Reportable Flaring Event
This section was Section 6.4.5 in previous drafts of Rule 4311. This section will require an annual report of all reportable flaring events that occur. The report shall include the primary cause and contributing factors of the flaring event, prevention measures considered or implemented to prevent recurrence, if appropriate an explanation of why the flaring was an emergency, and the date, time, and duration of each flaring event. This section has not been amended from the previous version.

Section 6.2.3 Annual Monitoring Report
This section was previously Section 7.7 in other drafts of the rule. Annual monitoring reports will be submitted to the APCO within 30 days following the end of the previous 12 month period and shall include data regarding volumetric flow, hydrogen sulfide, methane, and hydrocarbon content of vent gas composition, volumetric flows of purge and pilot gas, explanations of flare monitoring system downtimes, and a flow verification report.

For the sake of clarification District staff is elaborating on the annual monitoring reporting requirements. The reports will be due to the APCO within 30 days following the end of each 12 month period for which they are responsible. For example, this standard goes into effect on July 1, 2012 so the annual report would be due to the APCO within 30 days after July 1, 2012, not on July 1, 2012.

The section regarding emissions calculations has been removed from rule language. Staff have reviewed rule language and requirements and it has been determined that the section was unnecessary and irrelevant to rule requirement and standards. As this requirement is obsolete to the rule it has been removed. This is not a significant change to rule language as it was an erroneous standard that has been removed.
Section 6.3 Test Methods

Section 6.3.4 Testing and Sampling Methods for Flare Monitoring
A new section would be added to establish new test methods to fulfill flare monitoring requirements. The test methods in Section 6.3.4 are to be used to comply with monitoring requirements pursuant to Section 7.2 (Vent gas composition monitoring). The test methods presented are those established by the Bay Area and South Coast air districts as appropriate for monitoring requirements.

This section of the rule was amended to simplify it from previous draft versions. Previously, it was separated out into four subsections. As many of the test methods were repeated for each monitoring methodology, the Revised Proposed Draft Rule has been simplified in that there are no subsections, but it still includes all test methods previously presented before. New language has been added that provides operators the opportunity to use an alternative method as long as it has been approved by the APCO, ARB, and EPA.

Section 6.4 Compliance Determination
Section 6.4 would be moved from its previous location of Section 6.1 to provide fluidity and clarity to rule language. There have been no changes to standards or requirements of the Compliance Determination section.

Section 6.5 Flare Minimization Plan (FMP)
Section 6.5 was Section 6.4 in previous draft versions of the rule. A new section would be added to provide administrative requirements for FMPs. A FMP would be required for any petroleum refinery flare and for any other flare with a flaring capacity at or greater than 5 MMBtu/hr. Flares would be subject to commitments made in each individual flare minimization plan. The new section specifies what is to be included in the plans, timelines for compliance, FMP renewal instructions, and associated reporting requirements.

The due date for the initial submittal of FMPs to the District for review would be July 1, 2010. This will give facilities about twelve months after the rule adoption date to plan, write, and submit FMPs. A specific guideline for the formatting of the FMPs was purposely not specified in order to provide flexibility to industry in complying with this requirement. If a facility has a plan with another government entity that meets all requirements of the FMP, that facility may submit that plan in lieu of writing a new FMP provided that plan includes the information required by a FMP.
The effective date for implementation of FMP requirements is July 1, 2011, as referenced in Section 5.8 of the rule. This will give District staff twelve months to review, request corrections or additional information, and approve FMPs. Regardless of approval date of FMPs, compliance implementation will begin July 1, 2011. This means if a FMP is approved any date before July 1, 2011 enforcement of the FMP will not begin until July 1, 2011. These dates and this compliance enforcement decision was made in an effort to unify all dates for all facilities for FMP compliance and reporting. A provision has been added to rule language to enable facilities to protect confidential or proprietary information were the public to request to view said FMP.

The operator of a flare would be required to submit an annual report to the APCO to report each Reportable Flaring Event that occurred during the previous 12 month period. A reportable flaring event is any flaring where more than 500,000 standard cubic feet per day of vent gas is flared or more than 500 pounds of sulfur dioxide is emitted. This will make this rule as stringent as other districts in California, and District staff feel that 500,000 scf/day is a reasonable amount to request reporting because 500,000 scf converts into approximately 50 lb of NOx emissions as illustrated:

\[
(500,000 \text{ scf})(1000 \text{ Btu/scf})(1 \text{ MMBtu}/1,000,000 \text{ Btu})(0.1 \text{ lb NOx/MMBtu})=50 \text{ lb NOx}
\]

Section 6.5.3
This section has been modified from previous versions of the draft rules. It has been modified to improve clarity of rule requirements. Language has been added to indicate that submission of a revised FMP is necessary if the operator is installing or modifying any equipment where such a change would require an authority to construct (ATC) permit and would impact emissions from the flare. Changes to equipment that does not affect flare emissions would be made at the time of the five-year FMP review. This requirement would keep the FMP current when flare emissions are impacted but reduce unnecessary paperwork when such emissions are not affected.

Rule language has also been amended to clarify that ATCs deemed complete before the rule adoption date of June 18, 2009 shall not be required to update FMPs. Meaning that if an operator makes modifications which trigger an update of the FMP before the implantation of FMPs, that operator would not need to update the FMP because they essentially do not exist yet. However, if the operator obtains an ATC permit after the rule adoption date but does not implement changes per the ATC permit until after the implementation of the FMP, then that operator would have to update the FMP. As ATC permits have a two year life span, it would be possible for operators to get ATC permits prior to FMP implementation and not make such changes until a year or two after FMP implementation, for this reason District staff feel it would be necessary to update FMP information to reflect changes in order to keep FMP information current.
Finally, this section would be amended to explain that the removal or decommissioning of equipment listed in an FMP does not trigger an FMP update, except for the five year update, provided there is no increase in emissions associated with the decommissioning of the equipment.

These revisions from the last draft are not significant changes in that they do not change rule standards or requirements nor affect the District's ability to enforce compliance with rule language.

Draft rule language requiring the 30 day public review and comment period has been removed due to the redundancy associated with the public review and comment period provided via District Rule 2201 and Rule 2520. Also, Title V permits are renewed every five years and are subject to public comment, thus reducing redundancy. District staff also recognizes that the public has access to view FMPs via public records request; therefore the public is not being denied access to FMPs by removal of the redundant 30 day review language.

FMP language has been simplified from that of the BAAQMD and SCAQMD because staff feels we can achieve the same type of results as the South Coast and Bay Area did with less of a burden on industry. Staff feels this is appropriate also due to the small size of refineries and emissions from flares when compared to SCAQMD and BAAQMD. Please see Section III (Discussion) of this draft staff report for a more thorough discussion of flare emissions compared to SCAQMD and BAAQMD.

FMP renewals would be every five years to reduce the regulatory burden from industry. This is an appropriate measure because it aligns with the Title V permit renewals. It is as stringent as other districts because any time a facility modifies or installs equipment that requires a permit to operate, they must also update the FMP at the same time. Therefore, annual updates would be unnecessary. The five year standards shall remain to provide operators with the opportunity to reflect on the past five years of emissions, flaring, and activities at the facility, as well as evaluate the applicability of installing any new technologies that may have been developed during that five year period.

Other proposed FMP requirements include notifying the APCO within 24 hours of an unplanned flaring event and the submittal of an annual report to the APCO. The annual report shall summarize Reportable Flaring Events during the previous 12 month period, the result of the investigation of what caused the flare, prevention measures considered, if appropriate explanation of why flaring was an emergency and the date, time, and duration of the event. This portion of the FMP requirements of the rule language has been moved to Section 6.2.1 Unplanned Flaring Event in an effort to improve rule clarity.
Monitoring and Reporting Requirements
Previous versions of Draft Rule 4311 included all monitoring and reporting requirements for petroleum refinery flares and flares with a flaring capacity at or greater than 50 MMBtu/hr together in one Section of the rule. Conversations with stakeholders revealed that confusion was caused by having monitoring and reporting standards together. In an effort to reduce this confusion the Reporting Requirements have been moved to Section 6.2 Flare Reporting.

Monitoring requirements have been simplified from previous versions of the draft rule, District staff feels the same or a similar amount and type of information would be gathered but in a less complicated manner from that required by the SCAQMD and BAAQMD.

Section 6.6 Vent Gas Composition Monitoring
Previously Section 7.2, this section of the rule applies to petroleum refinery flares and to flares that have a capacity at or greater than 50 MMBtu/hour. The decision to include flares with capacities at or greater than 50 MMBtu /hr was made due to the high potential for emissions from such large flares. This section would be added to provide requirements of vent gas composition monitoring. Operators have five options to choose from in order to comply with monitoring requirements. Section 6.6.5 (formerly Section 7.2.5) has been amended since the previous version. Previously it only applied to petroleum refiners with flares that have a flaring capacity less than 50 MMBtu/hr, but has been amended to allow all flares subject this section to have this option for compliance.

Section 6.7 Pilot and Purge Gas Monitoring
Previously Section 7.3, this would be a new section to the rule and applies to petroleum refinery flares and to flares that have a capacity at or greater than 50 MMBtu/hour. The section would be added to provide a requirement for the monitoring of the volumetric flow of purge and pilot gas. Pilot and purge gas are to be monitored by flow measuring devices or other parameters as specified on the Permit to Operate so that volumetric flows can be calculated based on pilot design and the parameters monitored.

Section 6.8 Water Seal Monitoring
Previously Section 7.4, this section of the rule applies to petroleum refinery flares and to flares that have a capacity at or greater than 50 MMBtu/hour. This new section would be added to require the operator to monitor the water seal and record the water level and pressure of the water seal that services the flare each day, or as specified on the operating permit.
Section 6.9 General Monitoring

Previously Section 7.5, this section of the rule applies to petroleum refinery flares and to flares that have a capacity at or greater than 50 MMBtu/hour. This new section would set a limit for the period of flare monitoring system inoperation, provide requirements for what to do during periods of inoperation of certain sampling equipment, require that all monitors be maintained and calibrated, and provide guidelines for in-line continuous analyzers and flow monitoring data.

General monitoring requirement pertains to the monitoring equipment itself, not the flare or the equipment feeding to the flare. The timeline requirement of the 14 days per 18 consecutive months pertains to monitoring equipment, meaning the monitoring equipment itself shall not be down more than 14 days per 18 consecutive months. Also, timeline does not include periods when the system feeding the flare is not in operation because the flare will not be combusting fuel therefore there is no need to monitor it.

Section 6.10 Video Monitoring

Previously Section 7.6, this section of the rule applies to petroleum refineries only. An alternative monitoring to video monitoring has been written into rule language to provide flexibility for facilities to comply with the rule while still ensuring enforceability of the requirements. Language has been designed to give operators the opportunity to work with the District permit engineer to determine a monitoring methodology that will be appropriate for each facility based on its unique situation. Alternative monitoring will provide equivalent verification data that video monitoring would have provided.

As written into other air district rules in California video monitoring was added to provide additional information regarding flaring, not as a sole means of flare verification. The BAAQMD staff report describes video monitoring “The video monitoring requirements are intended to provide a backup to the extensive data that will be available after the rule’s other monitoring requirements go into effect. … With the proposed rule, video data will be redundant …”

The SJVAPCD rule faces unique challenges, due to the diversity of sources with which the rule applies. Unlike SCAQMD and BAAQMD which only regulate refinery flares, all the flares subject to Rule 4311 monitoring and reporting requirements are not necessarily petroleum refiners, but are from a diverse set of sources. Many of the flares may be at remote locations or mobile flares that are periodically relocated.

Section 7.0 Compliance Schedule

This section was Section 8.0 in previous versions of the draft rule, but was Section 7.0 of the original rule. Flares that are exempt under Section 4.0 that lose exemption status shall be in full compliance with all the applicable requirements of this rule on the date the exemption status is lost.
V. EMISSIONS AND EMISSIONS REDUCTIONS

A. Emissions

The emission inventory from sources subject to Rule 4311 with current controls in place is estimated to be 0.33 tons per day (tpd) NOx, 0.01 tpd PM2.5, and 0.63 tpd VOC in 2009. District staff previously believed the emissions inventory may have only accounted for the natural gas supplemental fuel to keep the flare pilot on at all times, and that it did not account for the actual amount of emissions from combusting the VOC–containing recovered waste gases from process operations. District staff has since updated the emissions inventory for purposes of this rule amending project based on research of the District database for emissions from flares at facilities subject to Rule 4311. The updated emissions inventory is presented in Table 5.

<table>
<thead>
<tr>
<th>Emissions</th>
<th>VOC</th>
<th>CO</th>
<th>NOx</th>
<th>PM 10</th>
<th>SO2</th>
</tr>
</thead>
<tbody>
<tr>
<td>Tons per day</td>
<td>0.208</td>
<td>0.756</td>
<td>0.401</td>
<td>0.058</td>
<td>0.181</td>
</tr>
</tbody>
</table>

Emissions from flaring include carbon particles (soot), unburned hydrocarbons, CO, partially burned and altered hydrocarbons, NOx, and if sulfur-containing materials are flared, sulfur dioxide (SO2). The quantities of hydrocarbon emissions generated relate to the degree of combustion. The degree of combustion depends largely on the rate and extent of fuel-air mixing and on the flame temperatures achieved and maintained. Properly operated flares achieve at least 98 percent combustion efficiency in the flare plume.

The tendency of a fuel to smoke or make soot is influenced by fuel characteristics and by the amount and distribution of oxygen in the combustion zone. Fuel characteristics include the carbon-to-hydrogen ratio and the molecular structure of the gases to be burned. Soot is eliminated by adding steam or air; hence, most industrial flares are steam-assisted and some are air-assisted. Flare gas composition is a critical factor in determining the amount of steam necessary.

Air is supplied to the flame as primary and secondary air. Primary air is mixed with the gas before combustion. Sufficient primary air must be supplied, if the amount of primary air is insufficient, the gases entering the base of the flare are preheated by the combustion zone, and larger hydrocarbon molecules crack to form hydrogen, unsaturated hydrocarbons, and carbon. The carbon particles may escape further combustion and cool down to form soot or smoke.
B. Emissions Reductions

Emission reductions resulting from this rule amending project are expected to be an estimated 0.06 tons per day of sulfur dioxide. This will be a 60% reduction of emissions from petroleum refineries. A complete analysis is presented in Appendix B of this staff report.

Review of Staff Reports and emissions data presented by the BAAQMD and SCAQMD since 2000 has revealed that FMP implementation has resulted in VOC and NOx emission reductions, in addition to expected SO$_2$ reductions. However, staff is not going to quantify those reductions in this rule amending project because we do not have accurate information as to how much reductions would be achieved by implementation of FMP requirements. SCAQMD and BAAQMD have both presented data to the public verifying that FMP implementation has resulted in emission reductions, as presented in Section III-Discussion of this staff report. Emission reductions resulting from FMP implementation will be quantifiable in the future by comparing new post-FMP emission data with the pre-FMP emission data of previous years. Administrative costs will be incurred by operators in efforts to comply with FMP and reporting requirements; however, these costs are expected to be minimal.

Under normal operating conditions, flares burn a small amount of gaseous fuel to keep the pilot flame lit in the event of an emergency waste gas release. Normal operations also include continuously burning sweep gas, which has a considerably greater flow rate than the pilot gas. Pressure relief valves, compressor seals, and analyzer purge lines also vent (either continuously or intermittently) to the flare.

Reduction of flaring can be achieved by installing or improving flare gas recovery units. Emissions can be further reduced by improved process control equipment, new flaring technology, and new ignition systems with low-pilot-gas consumption or elimination of pilots altogether with the use of new ballistic ignition systems.

**Flare Gas Recovery Units (FGRU)**

District staff believes the most efficient method of reducing SO$_2$ emissions from flaring is to reduce flaring by the installation of flare gas recovery units. Flare gas recovery units reduce emissions from flares by recycling the gases vented during emergency releases instead of combusting them in flare. The vent gases are collected in the flare header, compressed, cooled, and returned for re-use in the refinery as fuel gas or process feedstock. Flare gas recovery systems also have a safety feature built in that allows excess vent gas to be combusted in the flare in the event that the compressor system is at full capacity.
VI. COST EFFECTIVENESS ANALYSIS

Pursuant to CH&SC Section 40920.6(a), a cost effectiveness analysis is required for rules that implement BARCT. The purpose of the cost effectiveness analysis is to evaluate the economic reasonableness of the rule or rule amendments. The analysis also serves as a guideline for developing the control requirements of the rule.

SO₂ requirements implement BARCT and are the only emissions limits established in this rule amendment project, therefore a cost effectiveness analysis was conducted for compliance with SO₂ emissions limits only. Other draft amendments do not implement BARCT requirements, and therefore are not subject to the cost effectiveness analysis mandate. The cost effectiveness analysis determined that the SO₂ emissions limits are cost effective. The cost effectiveness analysis is presented in Appendix C of this draft staff report.

VII. SOCIOECONOMIC ANALYSIS

Pursuant to CH&SC Section 40728.5, “whenever a district intends to propose the adoption, amendment, or repeal of a rule or regulation that will significantly affect air quality or emissions limitations, that agency shall, to the extent data are available; perform an assessment of the socioeconomic impacts of the adoption, amendment, or repeal of the rule or regulation.”

This rule amending project will have financial implications to the operators associated with it; therefore the socioeconomic analysis has been conducted and includes costs associated with the draft FMP, and the monitoring and reporting requirements presented in the draft rule. District staff encouraged industry to contribute costs for the socioeconomic analysis.

As a part of the District’s socioeconomic analysis process, District staff convened a Focus Group to assist in the development of the socioeconomic report for the new proposed amended rule. The Focus Group consisted of volunteers and assisted with the socioeconomic analysis by gathering and providing information about costs expected to be incurred to comply with the rule and hypothetical business responses to those costs. This information and supporting data was provided to an outside consultant who identified and analyzed the socioeconomic impacts of the proposed amendments to Rule 4311 on the regional economy.

Please see Appendix D for further details.
VIII. RULE CONSISTENCY ANALYSIS

Pursuant to CH&SD Section 40272.2, District staff has prepared a rule consistency analysis of Rule 4311 that compares the elements of amendments with the corresponding elements of other District rules, federal regulations and guidelines that apply to the same source category or type of equipment. District staff found that none of the proposed requirements of these rules would conflict with other District rules, or federal rules, regulations, or policies covering similar stationary sources. The rule consistency analysis is presented in Appendix E of the Final Draft Staff Report.

VII. ENVIRONMENTAL IMPACTS

Pursuant to the California Environmental Quality Act (CEQA), District staff investigated the possible environmental impacts of the proposed amendments to Rule 4311. Based on the lack of evidence to the contrary, District staff has concluded that the proposed amendments to the rules will not have any significant adverse effects on the environment. Staff recommends filing a Notice of Exemption under the provisions of Public Resource Code 15061 (b) (3).

IX. REASONABLY AVAILABLE CONTROL TECHNIQUES (RACT) ANALYSIS

RACT Discussion

The Clean Air Act (CAA) Section 182(b)(2) states that ozone attainment plans shall assure that RACT for volatile organic compounds (VOC) is applied at certain sources. Section 182(f) extends federal RACT requirements to NOx rules and major NOx sources. District Rule 4311 is a NOx rule, therefore underwent a RACT analysis during this rule amending project. A RACT analysis requires an examination of a rule against Federal rules, regulations, and technology guidelines as well as comparing it against rules from other Districts in California. District Rule 4311 was compared to federal and state regulations and guidance. The following is a discussion of that analysis.

District staff compared emission limits, optional control requirements, and work practice standards in District Rule 4311 to comparable requirements in rules from the other Air Districts in California nonattainment areas. Further discussion and comparisons of District Rule 4311 with rules in other Air Districts in California is presented in Section III "Discussion" of the Final Draft Staff Report. District staff has concluded based on the aforementioned analyses, that District Rule 4311 satisfies RACT for flaring operations.
A. Comparison with Federal Rules and Regulations

EPA – Control Technique Guidelines (CTG) - There is no CTG for this source category.

EPA – Alternative Control Technology (ACT) - There is no ACT for this source category.

Standards of Performance for New Stationary Sources (NSPS)

40 CFR 60.18 (General Control Device Requirements) specifies certain minimum equipment performance standards for equipment used as control devices. In the case of flares, the CFR specifies no visible emission as well as certain equipment standards. Since NOx and VOC are invisible gasses, this portion of the CFR does not identify RACT for flares.

40 CFR 65.147 is part of the federal consolidation air rule. It essentially echoes 40 CFR 60.18 and as such does not identify RACT for flares.

National Emission Standards for Hazardous Air Pollutants (NESHAPs) and Maximum Achievable Control Technologies (MACTs) - There is no NESHAP or MACT for this source category.

B. Comparison with Other California Non-Attainment Areas

District staff compared emission limits, optional control requirements, and work practice standards in District Rule 4311 to comparable requirements in rules from the following California nonattainment areas:

- South Coast AQMD Rule 1118 (Emissions from Refinery Flares) amended February 1998
- Bay Area AQMD Regulation 12 Rule 11(Flare Monitoring at Petroleum Refineries) adopted June 4, 2003
- Bay Area AQMD Regulation 12 Rule 12 )Flares at Petroleum Refineries) adopted July 20, 2005
- Sacramento Metro AQMD has no specific prohibitory rule for flares
- Ventura County APCD has no specific prohibitory rule for flares.

SCAQMD Rule 1118 (Emissions from Refinery Flares)

The emissions data collected as a result of Rule 1118, between 1999 and 2003, was analyzed and resulted in recommendations being made for further strengthening emissions monitoring and reporting procedures, leading to the adoption of amendments on November 4, 2005. The 2005 amendments prohibit the flaring of vent gases except in emergency situations, or during specific operational needs such as startups, shutdowns, and turnarounds. Operational
requirements were established and practices to minimize flaring events, set specific annual SO$_2$ performance targets, require flares to operate in a smokeless manner, and require annual inspections of pressure relief devices directly connected to flares. The rule also contains provisions for refineries to give 24-hour advance notice for each large planned flaring activity, as well as to notify SCAQMD within 1-hour of unexpected flaring events. Also required is the submittal of quarterly reports detailing flow, emissions, and cause of each flaring event. SCAQMD also requires refineries to set up a 24-hour public telephone number for inquiries on flaring events.

*BAAQMD Regulation 12 Rule 11 and Regulation 12 Rule 12*

BAAQMD Rule 12-11 requires that operators monitor and record emissions data for flares at petroleum refineries. This rule enabled BAAQMD to collect emissions data from refineries. With emissions data BAAQMD was able to determine causes of specific flaring events, as well as estimate the quantity of emissions released during those events. As a result of findings obtained under Rule 12-11, Rule 12-12 was adopted. Rule 12-12 reduces emissions from flares by minimizing the frequency and magnitude of flaring. Rule 12-12 also prohibits the use of refinery flares without the refinery first creating, following, and annually updating an FMP for each flare. Facilities are required to submit flaring reports when a flare, at that facility, releases more than 500,000 standard cubic feet of gas per calendar day (scf/day). The flaring report must identify the cause and to avoid flaring from that cause in the future, if possible. The rule also requires continuous monitoring of the flare system’s knock-out drum water seal for leaks, and the submittal of annual reports to BAAQMD that evaluate flaring events that released less than 500,000 scf/day, but SO$_2$ emitted was more than 500 lbs.

**C. Conclusion**

District staff concludes that District Rule 4311 satisfies RACT for flaring operations in terms of emission limits and equipment standards.
X. REFERENCES

15. South Coast AQMD. “Control of Emissions from Refinery Flares”.
16. South Coast AQMD. “Rule 1118 - Control of Emissions from Refinery Flares” and “Staff Report”. November 4, 2005.
17. Ventura County APCD. “Rule 54 – Sulfur Compounds”. Adopted 7/2/68. Last revised 6/14/94.
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APPENDIX A

Summary of Significant Comments and District Responses For Revised Proposed Rule 4311 Dated May 21, 2009

June 18, 2009
Appendix A

Summary of Significant Comments and District Responses
For Proposed Rule 4311 dated May 21, 2009

US EPA REGION IX STAFF COMMENTS

1. **COMMENT:** EPA assumes the definition of “Planned Flaring” is intended to exempt activities from requirements for “Unplanned Flaring Events” in paragraph 6.2.1. Please review the rule language to evaluate whether it is clear and equivalent to requirements in SCAQMD 1118 and BAAQMD 12-12, where similar flaring must be minimized and is allowed pursuant to restrictions in an approved Flare Management Plan (FMP).

**RESPONSE:** Rule language in Section 6.2.1 is a reporting requirement only, and not intended to minimize flaring, therefore it is not equivalent to the South Coast AQMD and Bay Area AQMD Sections referenced by EPA. However, Section 5.8 and corresponding Section 6.5 specify requirements of FMPs and are intended to minimize flaring, and as such are equivalent to the SCAQMD and BAAQMD FMP requirements. These sections are actually more stringent than SCAQMD and BAAQMD which only apply their FMP requirements to petroleum refiners, while Rule 4311 applies FMPs to petroleum refiners and all other flares in all other industries.

2. **COMMENT:** Please clarify how the operations described in Section 3.26.4 will be subject to Section 5.8 FMP operational requirements and the Section 6.5.1 FMP requirements.

**RESPONSE:** Section 3.26.4 is merely a definition and does not provide any exemptions for planned flaring from the Section 5.8 requirements to operate flares according to the FMP. Section 4.0 (Exemptions) also does not provide any exemptions for gas production sources with no gas handling facilities, so such flaring would have to be conducted according to the Section 6.5.1 FMP, as required by Section 5.8.
3. **COMMENT:** Under Section 3.7, planned flaring is not an emergency; however, flaring off-specification gas, as defined in Section 3.26.5, is planned flaring unless the operator can demonstrate that flaring off-spec gas is an emergency. The rule should be revised to clarify that flaring off-specification gas is subject to FMP restrictions defined according to Section 6.5.1.5.

**RESPONSE:** Section 3.7 is the definition of an emergency event. The section does not specify that “off-specification gas” is exempt from the definition of an emergency. EPA is correct in that a planned flaring event is not an emergency and must be conducted according to the FMP. If an unplanned flaring event were to occur at a facility that flares off-specification gas, the operator would have to prove it was an emergency, or the flaring event would be declared an unplanned flare event and would be subject to Section 6.2.1 reporting requirements. Section 5.8 specifies that flares at petroleum refiners and flares with a flaring capacity equal to or greater than 5 MMBtu/hr are subject to FMP requirements. Please see the Response to comment 2, the staff report, and the proposed rule for further clarification on this matter.

4. **COMMENT:** Sections 6.5.1.4-6. Please review analogous requirements in SCAQMD 1118 and BAAQMD 12-12 which appear more stringent. For example, BAAQMD 401.4 requires, “A description and evaluation of prevention measures, including a schedule for the expeditious implementation of all feasible prevention measures...”

**RESPONSE:** Upon reviewing Section 6.5.1.4-6 staff has determined the only difference between Rule 4311 and SCAQMD and BAAQMD rules is the work "expeditious". However, expeditious is not defined in either the BAAQMD or the SCAQMD rules and can be left up to interpretation. Further, those rules do not actually require the implementation of all feasible prevention measures, nor set standards for what such measures might be. Therefore the District believe that Rule 4311 is as stringent as the other district’s rules.
5. **COMMENT:** Section 5.8. The following revision would clarify the requirement: “…flaring is prohibited unless… and all commitments listed in that plan pursuant to Section 6.5.1.3 have been met.”

**RESPONSE:** Section 5.8 states “…flaring is prohibited unless it is consistent with an approved flare minimization plan, pursuant to Section 6.5, and all commitments listed in that plan have been met.” Section 6.5.1.3 is a subsection of Section 6.5 therefore this requirement is already stated in the aforementioned rule language and no changes are necessary.

6. **COMMENT:** EPA recommends revising Rule 4311 to incorporate language clarifying that it is a violation if a source: (1) fails to correct a deficient FMP; or (2) fails to comply with all terms of an approved FMP.

**RESPONSE:** Rule 4311 is law, as adopted by the Governing Board of the District, and would be enforceable as such. To state that noncompliance is a violation of rule standards would be redundant and is unnecessary. Furthermore, Permit to Operate Conditions will be included, as appropriate, providing another avenue of stating requirements and proving enforcement. Therefore no changes will be proposed.

7. **COMMENT:** EPA recommends incorporating language similar to SCAQMD 1118(e)(2-4) and BAAQMD 12-12-403 regarding FMP submittal, review, revision and approval timelines.

**RESPONSE:** BAAQMD 12-12-403 sets the a series of deadlines for the District to follow when approving FMPs. Assuming that: 1) Only one day passes between APCO sending and operator receiving notification that corrective action must be taken and 2) Only one round of corrections are needed from the operator after the public comment period has ended. This process would take a minimum of 296 days to complete.

However, due to the stipulation presented in their APCO approval step and the possibility of multiple corrections needed, this process could be drawn out for even more months or years, thus delaying the implementation of FMP requirements.
SJVAPCD Rule 4311 gives only 365 days from FMP submittal deadline to implementation of requirements. This includes any and all revisions, corrections, etc. It is also important to note that the BAAQMD only receives 5 FMPs whereas SJVAPCD is expecting more than 120 FMP applications. It would be extremely taxing on district staff to process 120 FMPs in 45 days. By stating an undeniable implementation deadline the District has removed the possibility of never-ending revisions of FMPs and establishes continuity for both flare operators and District inspectors regarding compliance dates and inspections. Due to the possibility of repeated corrections and reviews of FMPs at BAAQMD and the defined timeline at SJVAPCD, this rule is as stringent if not more stringent than the BAAQMD rule.

SCAQMD Rule 1118 does not require FMPs for all petroleum refineries, only those exceeding the performance. The timeline for SCAQMD Rule 1118 gives a public comment period of 60 days with no timeline for the District to give responses or request corrections be made to the FMPs. Therefore SCAQMD does not have timelines that are more stringent than the SJVAPCD Rule 4311. Again, the District states a specific date for FMP implementation meaning Rule 4311 is more stringent because the SCAQMD FMP approval process could take months or years to approve.

Draft rule language requiring the 30 day public review and comment period is not in rule language because it is redundant with the public review and comment period provided via District Rule 2201 and Rule 2520. Also, the public has access to view FMPs via public records request therefore the public has not been denied access to FMPs.

8. **COMMENT:** EPA is concerned that provisions (formerly paragraphs 6.4.2, 6.4.3, 6.4.5, and 6.4.8 of the 1/08/09 draft of Rule 4311) regarding FMP submittal and review have been weakened or eliminated. For instance, under Rule 4311, FMPs would be reviewed only every five years and are available only through a public records request. The prior draft of the rule required annual FMP review and allowed for a 30-day public review and comment period.
RESPONSE: The Districts ability to enforce requirements have not been weakened or eliminated. The aforementioned changes have been made in an effort to streamline rule requirements; provide clarity as to what the District needs to enforce rule requirements; collect data pertaining to flare activities; and eliminate unnecessary, burdensome requirements that have no associated emission reductions and do not further the rule's intent.

Rule language requires update of FMP anytime changes are made to the flare system that impact emissions. Because of this requirement FMPs would remain current and up to date with a facilities flare and flaring activities. Therefore, requiring facilities to also update FMPs annually would be redundant and unnecessary. Any changes made to a facility that do not impact emissions would also not impact the FMP so it would not be necessary to update the FMP in those cases, however, any such changes would be updated in the five year FMP update regardless.

9. COMMENT: The Clean Air Act allows sources to designate material as confidential business information when submitting information to EPA. To avoid potential conflict or confusion between these federal provisions and analogous state and local provisions that may be incorporated into the federally enforceable SIP, this section should be removed from the rule. We believe sources could protect their CBI under State law regardless of whether State law provisions are referenced in the rule.

RESPONSE: District staff feel that the clause to provide a facility with the ability to protect it's confidential information is necessary. We believe the clause is necessary to prevent the apparent preclusion of state law when the rule is adopted into the Federal SIP. District staff feel it would be irresponsible to leave operators open to the possibility of being forced to reveal confidential information. Staff would be happy to have our legal counsel review any conflict or confusion caused between federal and state provisions.

10. COMMENT: We recommend adding to Rule 4311 language similar to SCAQMD 1118(e)(2) and BAAQMD 12-12-403.3 to require a 60-day public review period and response to public comments received prior to plan approval or disapproval. While SJV notes that similar requirements exist for major sources subject to Title V permits, it appears smaller sources are also subject to reasonable reporting requirements in SCAQMD and BAAQMD, but not in SJVAPCD.
RESPONSE: Our rule covers a much broader variety of sources, the majority of which have considerably smaller flares and flare activity than those covered in the BAAQMD and SCAQMD as elaborated upon in the Final Draft Staff Report. With regards to public access to FMP information, the public has access to any source and its FMP through public information requests. Should a source trigger public review under federal, state, or local requirements, any associated FMP would also be included in that notice, subject to the previously mentioned Confidential Information limitation.

11. COMMENT: We recommend revisions to Section 6.2. SJVAPCD has relaxed notification requirements (from 2 to 24 hours) and flare reporting (from 30-days to annual). In contrast, BAAQMD Rule 12-12 requires notification as soon as possible and flare reporting within 60 days.

RESPONSE: Rule 4311 varies greatly from the SCAQMD and BAAQMD flare rules in that our rule applies to a much greater variety of industries subject to a variety of working conditions and locations. Many flares in the SJVAB are located at remote locations that are not manned around the clock. One example of this type of flare would be the flares located in oil fields. The aforementioned flares do have monitoring devices to record when and how long unplanned flare events take place. It would be unfeasible to require operators to hire staff to monitor flares in remote locations at all times so they could be present to report an unplanned flare event.

Unlike police or fire fighters, the District is not a first responder in an emergency situation so immediate notification is not essential. During an emergency situation, it is more vital for the operator to be concerned about controlling the situation than satisfying a reporting requirement. Further, the rule provides up to 24 hours for reporting but in normal circumstances, the event would be reported well before the deadline. Amending the reporting of an unplanned flare event from 2 hours to 24 hours will not affect compliance, enforcement, or the District's ability to collect data regarding flare events. Therefore no change will be recommended.
12. **COMMENT:** Section 3.26 defines such an event as one where 500,000 scf/day of vent gas is flared. While SCAQMD Rule 1118 requires a Specific Cause Analysis for any flare event exceeding 500,000 scf, and an analysis to determine the cause of any flare event of 5,000 scf. Staff has explained that Rule 4311 has not incorporated similar provisions for these smaller flaring events because the emission rate is too low to justify pursuing a Specific Cause Analysis for a 5,000 scf flare event. It is not clear, however, whether SJVAPCD also believes the same is true for a 499,000 scf event, which would also be exempt under 4311 but not under 1118.

**RESPONSE:** It is the District’s prerogative to set the action levels commensurate with the other districts’ regulations, standard engineering sizes, and prevailing local considerations and conditions, although staff would be glad to review the engineering and legal reasoning for EPA’s suggested action level at 490,000 scf/event. Given that none of the rules require the operator to actually implement a corrective plan based on the analysis, it is irrelevant to debate whether the cutoff should be 490,000 or even 499,999 scf/event. For any unplanned flaring event, it is in the operator’s self-interest to analyze the cause and prevention of the event for various safety and economic reasons. Adding a reporting requirement to all events does not make good use of operators’ time or the District’s limited Compliance resources, unless emission reducing standards can be implemented and so far, no district nor the EPA had advanced the basis for such a standard.

13. **COMMENT:** We are concerned that this section sets an applicability cut-off, exempting flares with a capacity less than 5.0 MMBtu/hour from flare minimization plan requirements. Neither BAAQMD 12-12 nor SCAQMD 1118 contain this exemption. While we appreciate that this applicability cut off may be consistent with other SJVAPCD permitting regulations, the Staff Report does not provide analysis of the relative magnitude of the flaring from these exempt flares or explain why they should be exempted.
RESPONSE: Neither the BAAQMD nor the SCAQMD contain FMP requirements for flares at facilities other than petroleum refineries. SJVAPCD Rule 4311 requires all petroleum refiners, regardless of size to implement FMPs and additionally we require flares at non-petroleum refining facilities with flares greater than 5 MMBtu/hr to implement FMPs. This rule is more stringent than the SCAQMD and BAAQMD FMP rules with this regard. By setting the 5 MMBtu/hr threshold the rule captures 75% of all flares in the SJVAB and accounts for over 80% of NOx emissions in this emissions inventory category.

14. COMMENT: Section 6.6-6.9. While flares with a capacity of 5.0 MMBtu/hr are subject to the FMP requirements, only flares with a capacity or 50 MMBtu are subject to these monitoring and reporting requirements. Please explain why all flares subject to Section 5.8 prohibition and FMP requirements are not subject to monitoring and reporting as in SCAQMD and BAAQMD.

RESPONSE: Monitoring and reporting requirements in the SCAQMD and BAAQMD are only required for refineries. Rule 4311 mirrors the SCAQMD and the BAAQMD in that this flare rule also requires all refineries to comply with monitoring and reporting requirements. In addition to petroleum refineries being subject to these requirements, SJVAPCD is also requiring non-refineries with flare capacities at or equal to 50 MMBtu/hr to also comply with monitoring and reporting requirements making this rule more stringent than the SCAQMD and BAAQMD FMP rules.

ARB STAFF COMMENTS

1. COMMENT: Section 6.3.1 requires analysis of halogenated exempt compounds according to EPA Method 18 or EPA Method 422. That appears to be a typographic error and EPA Method 422 should be replaced by ARB Method 422.

RESPONSE: Changes have been made to update test method information. Please see Proposed Rule for changes.
STAKEHOLDER COMMENTS
Stakeholders sending comments:

Aera Energy LLC (AERA)
Western States Petroleum Association (WSPA)
Fresno/Clovis Regional Wastewater Reclamation Facility (FCWW)
Big West of California, LLC (BWC)
American Energy Operations, Inc (AEO)

1. **COMMENT:** The change made to the rule (Section 5.10) has the effect of subjecting flares with a rated capacity of 5 MMBtu/hr or greater, to flow monitoring and reporting requirements. This is a significant change which should have been discussed during workshop sessions. (WSPA)

**RESPONSE:** The original change was intended to clarify that the flares capable of experiencing a reportable event would need to be monitored so it could be determined of a reportable event had occurred. That language apparently captured flares that are too small to actually flare 500,000 scf/day. Section 5.10 has been amended to include language providing an exemption for flares that are incapable of achieving reportable flaring event quantities. As this change will not affect our ability to enforce compliance or collect reporting information this is not considered to be a significant change. Please see draft rule and staff report for further explanation.

2. **COMMENT:** The District should reconsider the applicability of the FMP requirements and monitoring requirements for portable well test and safety flares. As previously suggested, operators believe a limited exemption from FMP and monitoring requirements for these types of flares is warranted. (WSPA)

**RESPONSE:** No changes have been made to rule language pertaining to this comment since such flares could have emissions comparable to their stationary counterparts. A more detailed explanation of how compliance with this standard will be enforced by the District has been added to the Final Draft Staff Report Section IV B (Current And Proposed Regulations, Proposed Draft Amendments) Subsection 5.8 (Flare Minimization Plans).
3. **COMMENT:** The current wording of Section 6.4.3 is such that the submission of an application for any type of authority to construct would trigger the requirement for approval of a revised FMP. A new FMP be need to be approved when installing or modifying equipment, even if it is already addressed in an approved FMP or for changes that do not result in any increase in emissions. The proposed requirement is too broad and would require that operators constantly revise and submit new FMPs. (WSPA)

**RESPONSE:** Rule language has been clarified to require that submission of a revised FMP would be needed only if changes are made that would require an authority to construct (ATC). Another clarification is that only ACTs deemed complete after rule implantation would be subject to FMP renewals. Please see Final Draft Staff Report for further explanation and the Proposed Rule for language changes.

4. **COMMENT:** The District should reconsider a prior request and allow reporting of unplanned flaring events within 24 hours of the next regularly scheduled work day or within 24 hours of discover, which ever occurs first. (WSPA)

**RESPONSE:** The rule language has been amended to reflect that suggestion. This will not be a relaxation of the rule standards because it is a reporting requirement and this new standard will make this rule more in line with the BAAQMD and SCAQMD flare rules because petroleum refineries are monitored, whereas in the SJVAPCD because the flares are located at a variety of locations many flares are unmanned. For example flares in oil fields are at remote locations and are unmanned flares. Please see Final Staff Report and Proposed Rule for amendments and further explanation.

5. **COMMENT:** The flare efficiency used in the calculations required by Section 6.2.3.8 be established at 99%. Studies conducted by the EPA, the Chemical Manufacturers Association and flare manufacturers have shown that flare VOC destruction efficiencies range from 98.5% to 99.75% with an average VOC destruction efficiency of 99%. (WSPA)

**RESPONSE:** Staff have reviewed rule language and requirements and it has been determined that the Section 6.2.3.8 is unnecessary an irrelevant to rule requirement and standards. As this requirement is obsolete to the rule it has been removed.
6. **COMMENT:** The rating of the flare is dependent upon the safety devices that vent to it. The design parameters for a flare are based on Federal and State regulations which establish criteria for operating safety relief devices. Although a flare may be rated at a high enough capacity to safely destroy gases from the process, if the safety devices that discharge to the flare are seldom operated, there will be minimal emissions from the flare. The District should be focused on flares that burn significant volumes of gases in reality, not on flares that are rated at higher capacities yet seldom used. (AERA, AEO)

**RESPONSE:** Rule language regarding the standard chosen to determine the threshold for FMP and monitoring/reporting requirements is based on the size of the flare to provide a simplistic clear cut manner in which operators can use to determine if their flare is subject to rule requirements. Rule language requires facilities subject to FMPs (equal to or greater than 5 MMBtu/hr) to report unplanned flaring events, as well as an annual report summarizing all flaring events in which more than 500,000 scf/day or 500 lbs of SO$_2$ is flared. Flares that are infrequently used, would therefore have less actual reporting than those which are operated more frequently. Finally, monitoring requirements allow for the level and type of monitoring to be tailored, as determined by a case-by-case analysis, as permit conditions.

7. **COMMENT:** As currently drafted, flares with a flaring capacity less than 5 MMBtu/hr are exempt from having to be included in a FMP. Assuming a 5 MMBtu/hr flare burns natural gas with a heating value of 1,000 Btu/hr continuously for a year, the flare would consume 43.8 MMcf/yr. An annual deminimus limit be established to exempt limited use flares from the administrative burden from having to file FMPs or should be exempt from the scheduled submittal of an updated FMP. (AERA)
RESPONSE: The 5 year update of FMPs was put in place to make this rule as stringent as other FMP rules in other districts, as well as to ensure that FMP information the District has for a facility is current. The BAAQMD flare rule requires updated FMPs annually. Because rule language requires an update of FMP prior to installing or modifying equipment that requires an ATC permit and that will impact the emissions from the flare pursuant to Section 6.5.3, staff is able to keep the mandatory updates at every five years instead of annually. This effort has been made to reduce the burden of industry to every five years instead of annually. Also please see the response to Comment 6.

8. COMMENT: Automated vent gas composition monitoring should not be required for flares that burn vent gas with consistent composition. The composition of the gas does not change significantly. A pre-approved schedule be developed for composition monitoring of oilfield flares. Semi-annual sampling will sufficiently document the stable nature of the gas composition. (AERA)

RESPONSE: Proposed rule language has been clarified to remove redundant or unnecessary monitoring requirements. As stated in Response to Comment 6, monitoring requirements allow for the level and type of monitoring to be tailored, as determined by a case-by-case analysis, as permit conditions. Please see Section 5.10 of rule language and the Final Draft Staff Report for further language and explanation of these changes.

9. COMMENT: The District set guidelines that would require a facility to abide by Draft Rule 4311 Section 6.4 FMPs by taking the total annual scf usage amount of a flare to trigger FMP’s. For example: The District would take the flares highest “normal use” fuel usage from the past four years, the District would set that usage as the trigger point for filing FMPs. The District will be able to easily obtain the usage data from the annual emissions inventory reports which the facilities already report. Once a trigger point has been set for a facility the District will use the previous year’s fuel usage to determine if an FMP submittal will be required for the following year then notify the facility. (FCWW)
RESPONSE: District staff feel FMP requirement enforcement based on flare usage would significantly complicate rule language and possibly cause confusion from industry as to whether or not they are subject to FMP requirements, especially since flare usage can vary greatly from year to year. In order to make rule requirements based on flare usage, as stated in the comment industry would have to use flare monitoring data from the previous four years, analyze it, and determine from there if they would be required to comply with Section 5.8. In order to keep up to date this evaluation would need to be conducted every year, meaning industry would still need to monitor the flares, take that information and submit it to the District for analyzing to determine if they are subject to FMP requirements. This could potentially greatly increase the amount of paperwork, fees, and labor required by industry to determine if they need to do an FMP.

10. COMMENT: Title V Facilities spend a tremendous amount of time and labor on reports, recordkeeping, source testing, application filing, annual fees, and quarterly fees. During these hard economic times FMP’s will only add to the cost in producing more reports. (FCWW)

RESPONSE: Because this rule addresses a large number of operations, requirements regarding the format of FMPs has been written to give industry some flexibility in submitting required information to maintain compliance. If the facility is a Title V facility and reports required by Title V fulfill information requirements industry is allowed to submit that information to satisfy Rule 4311 requirements, to the extent feasible. Please see Final Draft Staff Report Section IV B (Current and Proposed Regulations – Revised Proposed Draft Amendments) Subsection 6.5 (Flare Minimization Plans) for further language on this issue.

11. COMMENT: The District should work with flare operators in formulating Rule 4311 implementation procedures to allow operators already required to submit flare minimization plans and flaring incident reports required by other rules, permits, or enforceable consent decrees to submit those plans and reports to satisfy Rule 4311 requirements, to the extent feasible. (BWC)
RESPONSE: It is the District’s intent to work with industry to determine best methods of implementation of rule standards, without relaxation of rule standards or requirements. Please see Final Draft Staff Report Section IV B (Current and Proposed Regulations – Revised Proposed Draft Amendments) Subsection 6.5 (Flare Minimization Plans) for further language on this issue.
APPENDIX B

Emission Reduction Analysis
For
Revised Proposed Amendments to Rule 4311

June 18, 2009
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I. SUMMARY

District staff has estimated emissions reductions of sulfur, expressed as sulfur dioxide (SO\textsubscript{2}), from petroleum refiners due to compliance with draft amendments to Rule 4311 (Flares). The SO\textsubscript{2} emission reductions estimates are based on the best available information at the time that this report was written. District staff are proposing emission target limits on SO\textsubscript{2} only, for petroleum refiners only, which is similar to the SCAQMD flare rule. Volatile Organic Compound (VOC), oxides of nitrogen (NO\textsubscript{x}), and particulate matter (PM) emission reductions will not be accounted for in this analysis.

The District permit database indicates that there are four petroleum refiners in the San Joaquin Valley Air Basin, all of which are subject to Rule 4311. The 2008 baseline emissions inventory for SO\textsubscript{2} emissions from petroleum refiners in the San Joaquin Valley Air Basin is 0.10 tons per day (tpd). District staff estimates that approximately 0.06 tpd (60\%) of SO\textsubscript{2} emissions reductions would be achieved by 2017.

II. BACKGROUND

The proposed draft amendments to Rule 4311 would require affected operators to comply with SO\textsubscript{2} emission limits. The SO\textsubscript{2} emission limits would be determined based on Reported Processing Capacity instead of Actual Production Levels, making this rule similar to the SCAQMD rule limits. Three of the operators are either in compliance with the final SO\textsubscript{2} limit or are not producing at this time. The remaining operator will be required to reduce their SO\textsubscript{2} emissions according to the schedule below.

- 2011: 1.5 tons of SO\textsubscript{2} per MMbbl reported processing capacity
- 2017: 0.5 tons of SO\textsubscript{2} per MMbbl reported processing capacity

III. EMISSION REDUCTION ANALYSIS

District staff used the crude distillation capacity as presented by the Energy Information Administration (EIA) as the baseline for production capacity. District staff made the following assumptions for this emission reduction analysis.

1. Petroleum refiners will maintain production levels in future years at roughly the same level as the baseline year.
2. Actual Production Levels of petroleum refineries are typically 80\% of their Reported Processing Capacity, according to the EIA website.

The District emission inventory database reveals that only one petroleum refiner will be affected by the new SO\textsubscript{2} emission limits. The other refiners in the San Joaquin Valley Air Basin (SJVAB) currently have SO\textsubscript{2} emissions below the 2017 emission limit.
The affected petroleum refiner has a Reported Processing Capacity of 24.09 MMbbl/yr and an Emissions Inventory of 36.04 tons/year of SO\textsubscript{2} emissions.

For purposes of these emissions reduction calculations the 36.04 tons/year of SO\textsubscript{2} emissions will be used as the baseline SO\textsubscript{2} emissions.

Emission reductions are calculated with the Maximum Allowable SO\textsubscript{2} emission limits based on the Reported Processing Capacity of 24.09 MMbbl/yr times the SO\textsubscript{2} Performance Limits.

For 2011, the reduction is calculated as follows:

\[
\text{Emission Reduction} = \text{Baseline Emissions} - \text{Maximum SO}_2 \text{ emissions} \\
= 36.04 \text{ tpy} - (\text{Reported Processing Capacity} \times \text{SO}_2 \text{ Performance Limit}) \\
= 36.04 \text{ tpy} - 36.14 \text{ tpy} \\
= 0 \text{ tpy} \text{ (Baseline emissions are less than the Maximum SO}_2 \text{ Emission limit)}
\]

For 2017, the reduction is calculated as follows:

\[
\text{Emission Reduction} = \text{Baseline Emissions} - \text{Maximum SO}_2 \text{ emissions} \\
= 36.04 \text{ tpy} - (\text{Reported Processing Capacity} \times \text{SO}_2 \text{ Performance Limit}) \\
= 36.04 \text{ tpy} - 12.05 \text{ tpy} \\
= 23.99 \text{ tpy reductions} \\
= 0.06 \text{ tpd SO}_2 \text{ Emission Reductions} \ (23.99/365)
\]

Once fully implemented in 2017, the SO\textsubscript{2} limits will result in about 0.06 tons per day of SO\textsubscript{2} emission reductions.
APPENDIX C

Cost Effectiveness Analysis
For
Revised Proposed Amendments to Rule 4311

June 18, 2009
APPENDIX C
Cost Effectiveness Analysis

I. INTRODUCTION

The California Health and Safety Code (CH&SC) 40920.6(a) requires the San Joaquin Valley Unified Air Pollution Control District to conduct both an "absolute" cost effectiveness analysis and an "incremental" cost effectiveness analysis of available emission control options prior to adopting each Best Available Retrofit Control Technology (BARCT) rule. A cost effectiveness analysis examines the added cost, in dollars per year, of the control technology or technique, divided by the emissions reductions achieved, in tons per year.

\[
\text{CostEffectiveness($ / \text{ton})} = \frac{\text{Compliance cost($ / \text{year})}}{\text{Emission Reduction(ton / year)}}
\]

The purpose of conducting a cost effectiveness analysis is to evaluate the costs of obtaining specific emission reductions, as it applies to operators in the San Joaquin Valley Air Basin. The analysis also serves as a guideline in developing the control requirements of a rule.

Incremental cost effectiveness is intended to measure the change in costs (in $/year) and emissions reductions (in tons reduced/year) between two progressively more effective control options or technologies. For this rule project, the limits are considered the lowest achieved in practice, therefore, no incremental cost effectiveness analysis was conducted.

Rule 4311 applies to flares with the exception of flares at municipal solid waste landfills subject to Rule 4642, flares subject to 40 CFR 60 Subpart WWW or Subpart Cc, and flares at stationary sources that have a potential to emit, for all processes, less than ten tons per year of VOC and less than ten tons per year of NOx. Amendments to Rule 4311 would require facilities with flares subject to Rule 4311 to create and implement flare minimization plans (FMPs). Amendments would also require increased monitoring and reporting standards at petroleum refining facilities and at facilities with flares that have a flaring capacity of 50 million British thermal units per hour (MMBtu/hr). Finally, amendments will implement emission targets for sulfur emissions, expressed as sulfur dioxide (SO\(_2\)), at petroleum refineries. As only requirements for SO\(_2\) targets will be requiring BARCT, a cost effectiveness analysis was only conducted on costs associated with compliance of the new SO\(_2\) limits. Costs associated with monitoring will be included in the socioeconomic analysis but are not appropriate for this section since they do not have claimed emission reductions.
II. SUMMARY AND CONCLUSION

A. Absolute Cost Effectiveness Analysis

Absolute cost effectiveness of a control option is the added cost of a control technology or technique, divided by the emission reduction achieved (in tons reduced per year). The costs typically include capital equipment costs, engineering costs, labor and maintenance costs. The estimated low absolute cost effectiveness for this analysis, based on SCAQMD cost data, is $6,290 per ton of SO$_2$ emissions reduced. The estimated high absolute cost effectiveness for this analysis, based on operators’ cost information, is $42,256 per ton of SO$_2$ emissions reduced. The calculations are presented in Section IV (Cost Effectiveness Analysis) of this appendix.

This draft rule amendments call for SO$_2$ performance standards for petroleum refiners to be implemented in a two-phase plan.

- The first phase would be effective by January 1, 2011 and staff has determined that all petroleum refineries in the SJVAB are currently compliant with that SO$_2$ emissions limit.
- The second phase would be effective on and after January 1, 2017. Based on analysis of the permit database, petroleum refiner crude processing capacity and emission inventory it has been determined that only one petroleum refinery would need to be modified to comply with the more stringent SO$_2$ performance standards.

Therefore, this cost effectiveness analysis will only apply to one petroleum refinery, because it is the only facility required to make changes to comply with the phase-two emission reduction. The other refineries do not have either an emission reduction or compliance costs to comply with the SO$_2$ limit.

B. Incremental Cost Effectiveness Analysis

Incremental cost effectiveness (ICE) is intended to measure the change in costs (in $/year) and emissions reductions (in tons reduced/year) between two progressively more effective control options or technologies. ICE compares the differences in costs and the differences in emissions reductions of candidate control options. ICE does not reveal the emission reduction potential of the control options. Unlike the absolute cost effectiveness analysis that identifies the control option with the greatest emission reduction, ICE does not present any correlation between emission reductions and cost effectiveness. Therefore, the relative values produced in the ICE analysis and the absolute cost effectiveness values are not comparable and cannot be evaluated similarly.

The District is required to conduct an ICE analysis for BARCT rules or emission reduction strategies in accordance with Health and Safety Code Section 40920.6 when
there is more than one control option. In this case, District staff’s research concluded that there is no other technologically and economically feasible control option that is more stringent than a flare gas recovery and treating system. Since there are no other stringent emission control options to compare with a flare gas recovery and treating system, conducting the ICE analysis is not necessary.

III. SOURCES OF COST DATA

Preliminary cost information is based on the South Coast Air Pollution Quality Management District (SCAQMD) staff report for Rule 1118 (Control of Emissions from Refinery Flares). Staff has since received additional cost information from the petroleum refinery to which this analysis applies, and refined the analysis to include those costs.

IV. COST EFFECTIVENESS ANALYSIS

A. Cost Effectiveness Analysis Procedure

In conducting the cost effectiveness analysis of a rule, District staff generally use the following procedure: (1) identify typical operating conditions for units affected by the rule; (2) identify the control technologies that can achieve the proposed emission limits; (3) estimate the average annualized cost of each control option; (4) calculate the potential average emissions reduction of a control option; and (5) calculate the absolute cost effectiveness of a given equipment setting.

The preliminary cost effectiveness analysis accounted for the estimated cost of a 2 MMBtu/hr capacity flare gas recovery and treating system, based on cost data provided from South Coast during their flare amending rule project. This cost effectiveness analysis has since been amended from the previous version to include the cost for a flare gas recovery study, enhanced flare gas monitoring, and the annual cost for an additional compliance field staff member. These additional costs were provided by the affected operators.

Also, this analysis has been amended to include an analysis for the estimated cost of the installation of the flare gas recovery system as quoted by the petroleum refiner who would be required to install it prior to January 1, 2017 to comply with the phase-two SOx performance standards. A detailed cost estimate was not provided and District staff has requested clarification on the costs given.
B. Absolute Cost Effectiveness (ACE) Calculation Method

The following are assumptions used during this cost effectiveness analysis:

1. The petroleum refiner will install a new flare gas recovery and gas treating system to comply with new SO\textsubscript{2} emission limits.
2. The annual costs, such as for parts, maintenance, repairs, calibration, taxes, fuel, operation, and electricity represent 10 percent of the capital cost.
3. $2.17 million in 2005 is equivalent to $2,395,555 ($2.4 million) in 2008 dollars.
4. 1 cubic foot of Refinery gas has a value of 1,029 Btu.
5. The petroleum refiner that will be affected by the SO\textsubscript{2} emission limits has flares with an estimated combined flaring capacity of 7.5 MMBtu/hr.

The low estimate absolute cost effectiveness of a control technology is calculated as follows:

1. A case study conducted by SCAQMD revealed that the average cost to install a flare gas recovery and treating system is $2.4 million per million standard cubic feet per day (mmscf/day) of flaring capacity. For a 7.5 MMBtu/hr flare the capital cost is as follows:

   \[ \text{Capital cost} = \left( \frac{\$2.4 \text{ million/mmscf}}{1 \text{ mmscf}} \right) \times \left( \frac{1 \text{ mmscf}}{1,029 \text{ MMBtu}} \right) \times \left( \frac{24 \text{ hours}}{1 \text{ day}} \right) \times (7.5 \text{ MMBtu/hour per flare}) \]

   \[ = \$420,000 \]

2. Add to Capital Cost other one time costs, as submitted by Big West of California, and supported by the Refiners council.
   Flare Gas Recovery Study: $200,000
   Enhanced Flare Gas Monitoring: $300,000

   \[ \$420,000 + \$500,000 = \$920,000 \]

3. Determine an equivalent annual cost using a capital recovery factor based on an assumed interest rate of 10 percent and equipment life of 10 years. The annualized capital equipment cost is calculated by multiplying the installed equipment cost by the capital recovery factor of 0.1627.

   \[ A = \frac{i(1+i)^n}{(1+i)^n - 1} \]

   \[ A = \frac{0.1(1+0.1)^{10}}{(1+0.1)^{10} - 1} \]

   \[ = \frac{0.1(1.1)^{10}}{(1.1)^{10} - 1} \]

   \[ = \frac{0.1(2.8517)}{2.8517 - 1} \]

   \[ = \frac{0.28517}{1.8517} \]

   \[ = \$0.1538 \]

   This represents the annual equivalent cost of the installed equipment.
where;

\[ A = \text{Equivalent Annual Control Equipment Capital Cost} \]
\[ P = \text{Present value of the control equipment, including installation cost} \]
\[ i = \text{Interest rate (use 10\%, this is the established District standard for interest rate percentages for cost effectiveness analysis).} \]
\[ n = \text{Equipment life (assume 10 years)} \]

\[ A = \frac{0.10(1+0.10)^{10}}{1+0.10)^{10} - 1} \]

\[ = \frac{920,000 \times 0.1627}{1} \]

\[ = \$149,684 \]

4. Determine the annual electricity, fuel, and operation and maintenance costs of a control technology.

\[ \$149,684 \times 10\% = \$14,968 \]

5. Calculate the annual cost. (Add the costs in Step 3 and Step 4).

\[ \$149,684 + \$14,968 = \$164,652 \]

6. Add estimated annual costs provided by Big West of California to the annual cost. (Add the costs in Step 5 and cost presented below)

   Compliance Field Staff: $75,000/year

\[ \$164,652 + \$75,000 = \$239,652 \]

7. Calculate the emission reduction in tons/year (As shown in Appendix B).

\[ \text{22 tpy} \]

8. Calculate the absolute cost effectiveness. (Divide the cost in Step 6 by the annual emissions reduction of the pollutant in tons/year).

\[ \$239,652 / 22 \text{ tpy} = \$10,893 \text{ per ton} \]
The high estimate absolute cost effectiveness of a control technology is calculated as follows:

1. Based on information provided by Big West of California:

   Capital cost = $8,000,000

2. Add to Capital Cost, other one time costs, as submitted by Big West of California.
   Flare Gas Recovery Study: $200,000
   Enhanced Flare Gas Monitoring: $300,000

   $8,000,000 + $500,000 = $8,500,000

3. Determine an equivalent annual cost using a capital recovery factor based on an assumed interest rate of 10 percent and equipment life of 10 years.
   The annualized capital equipment cost is calculated by multiplying the installed equipment cost by the capital recovery factor of 0.1627.

   \[
   A = \frac{i(1+i)^n}{(1+i)^n - 1}
   \]

   where;
   A = Equivalent Annual Control Equipment Capital Cost
   P = Present value of the control equipment, including installation cost
   i = Interest rate (use 10%, this is the established District standard for interest rate percentages for cost effectiveness analysis).
   n = Equipment life (assume 10 years)

   \[
   A = \frac{0.10(1+0.10)^{10}}{(1+0.10)^{10} - 1}
   \]

   = $8,500,000 \times 0.1627
   = $1,382,950

4. Determine the annual electricity, fuel, and operation and maintenance costs of a control technology.

   $1,382,950 \times 10\% = $138,295
5. Calculate the annual cost. (Add the costs in Step 3 and Step 4).

\[ \$1,382,950 + \$138,295 = \$1,521,245 \]

6. Add estimated annual costs provided by Big West of California to the annual cost. (Add the costs in Step 5 and cost presented below)

Compliance Field Staff: $150,000/year

\[ \$1,521,245 + \$150,000 = \$1,671,245 \]

7. Calculate the emission reduction in tons/year (As shown in Appendix B).

36 tons per year

8. Calculate the absolute cost effectiveness. (Divide the cost in Step 6 by the annual emissions reduction of the pollutant in tons/year).

\[ \frac{\$1,671,245}{36 \text{ tpy}} = \$42,256 \text{ per ton} \]

Staff assumed that the eight million dollars cited by the petroleum refinery accounts for a flare gas recovery system with a much larger capacity that would be designed to eliminate all emission of sulfur oxides from the flare systems. With this assumption, the \( \text{SO}_2 \) emissions reduced in tons per year would actually be 36 tons per year.

Table 1 below provides a summary of the two cost effectiveness calculations presented in this cost effectiveness analysis.

<table>
<thead>
<tr>
<th></th>
<th>Capital Cost</th>
<th>One Time Costs</th>
<th>Total Annual Cost</th>
<th>( \text{SO}_2 ) Reduced Tons/Year</th>
<th>Other Annual Costs</th>
<th>Cost Effectiveness $/Ton</th>
</tr>
</thead>
<tbody>
<tr>
<td>Low Estimate</td>
<td>$420,000</td>
<td>$500,000</td>
<td>$149,684</td>
<td>22 tpy</td>
<td>$75,000</td>
<td>$9,985</td>
</tr>
<tr>
<td>High Estimate</td>
<td>$8,000,000</td>
<td>$500,000</td>
<td>$1,521,245</td>
<td>36 tpy</td>
<td>$75,000</td>
<td>$42,256</td>
</tr>
</tbody>
</table>
V. REFERENCES

1. Big West of California, email with costs in it.
2. Energy Information Association (EIA). “Manufacturing Energy Consumption Survey: Btu Conversion Factors Table”
4. South Coast Air Quality Management District. “Rule 1118 Draft Staff Report”.
APPENDIX D

Socioeconomic Impact Analysis
For
Revised Proposed Amendments to Rule 4311

June 18, 2009
DRAFT RULE 4311 (FLARES):
SOCIOECONOMIC IMPACT ANALYSIS

APRIL 21, 2009

Prepared for
San Joaquin Valley Air Pollution Control District

Prepared by
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CONTENTS

1. Executive Summary ................................................................. 5
2. Introduction ........................................................................... 7
3. Description of Draft Rule 4311 .............................................. 9
   Existing Conditions .............................................................. 9
   Proposed Draft Amendments ............................................. 10
4. Methodology ......................................................................... 11
5. Impacted Industries Subject To Proposed Amendments to Draft Rule 4311 .............. 13
   5.1 Regional Demographic and Economic Trends .................. 13
   5.2 Description of Affected Industries .................................. 17
6. Socio-economic Impacts ........................................................ 27
   6.1 Compliance Cost Estimates ........................................... 27
   6.2 Business Responses to Compliance Costs ...................... 27
   6.3 Impacts on Affected Industries ...................................... 27
1. EXECUTIVE SUMMARY

The proposed amendments to Rule 4311 will affect establishments in a limited set of industries, particularly oil refinery and oil production. The analysis shows that oil-related industries experienced tremendous surges in revenues and profits, starting in late 2005 and continuing into 2008. With respect to oil-related industries, the analysis shows that annual costs stemming from the proposed amendments are small in relation to estimated industry net profits, falling below the threshold used for purposes of analyzing whether rule impacts are significant or not. The proposed amendments will also affect a number of industries outside of petroleum. These industries are not significantly impacted by proposed amendments.
“This section intentionally left blank”
2. INTRODUCTION

The San Joaquin Valley Unified Air Pollution Control District (“District”) seeks to amend Rule 4311 (Flares) to implement emission control requirements listed in the 2007 Ozone Plan as well as the 2008 PM 2.5 Plan. In particular, the District is contemplating changes that are already contained in flare rules or permit conditions in other air districts in California, to ensure that Rule 4311 meets federal RACT and BACM requirements as well as CH&SC requirements to implement BARCT and all feasible control measures (AFCMs). The report is prepared pursuant to the provisions of AB2051 (Section 40728.5 of the California Health and Safety Code), which requires an assessment of socioeconomic impacts of proposed air quality rules. The findings in this report can assist District staff in understanding the socioeconomic impacts of the proposed amendments, and can assist staff in preparing a refined version of the rule. Figure 1 is a map of the eight-county region that comprises the San Joaquin Valley Air Basin. As indicated in the map, Kern County is not completely in the District.

Source: ADE, Inc.
“This section intentionally left blank”
3. DESCRIPTION OF DRAFT RULE 4311

In developing the draft amendments to Rule 4311, District staff evaluated the emission reduction potential of flare minimization plans (FMP) and other provisions that other districts’ rules have already implemented, and determined that it is feasible to require similar emission controls for flares that are operating within the District. However, other relevant findings, available technical information, and input from stakeholders would be considered during the rule development process in order to further refine the draft rule amendments. The discussion below first summarizes existing conditions with regard to the Rule 4311. Then, we reference proposed amendments to Rule 4311.

EXISTING CONDITIONS

Source categories subject to Rule 4311 currently includes flares associated with oil and gas production, combustion, sewage treatment, incinerators, petroleum refining, and VOC control. Flaring is a high temperature oxidation process used to burn combustible components, mostly hydrocarbons, of waste gases from industrial operations. 95 percent of the waste gases flared are natural gas, propane, ethylene, propylene, butadiene and butane. During combustion, gaseous hydrocarbons react with atmospheric oxygen to form carbon dioxide (CO2) and water. In some waste gases, carbon monoxide (CO) is the major combustible component.

Flares generate air pollutants such as nitrogen oxides, sulfur dioxide, carbon monoxide, and particulate matter, in addition to the possible release of hydrocarbons that have not been completely combusted.

GENERAL EQUIPMENT DESCRIPTION

There are two general types of flares, elevated and ground flares. Flares are categorized by the height of the flare tip, and by the method of enhancing combustion by mixing at the flare tip (i.e., steam-assisted, air-assisted, pressure-assisted, or non-assisted).

Elevated flares are more common and have larger capacities than ground flares. In elevated flares, a waste gas stream is fed through a stack, which can be over 100 meters tall and is combusted at the tip of the stack. An elevated flare consists of five components: a gas collection header (to collect gases from various process units), a proprietary seal, water seal, or purge gas supply (to prevent flash back), a single or multiple-burner unit in the flare stack, and gas pilots and igniter.

Ground flares vary in complexity and can consist either of conventional flare burners discharging horizontally with no enclosures or of multiple burners in refractory-lined steel enclosures.

Complete combustion requires proper mixing of air and waste gas. Smoking may result from combustion, depending upon waste gas components and the quantity and distribution of combustion air. Waste gases containing methane, hydrogen, CO, and ammonia usually burn without smoke, while waste gases containing heavy hydrocarbons cause smoke.
An external momentum force, such as steam injection, is used for efficient mixing of air and waste gas, and turbulence, which promotes smokeless flaring of heavy hydrocarbon waste. Other external forces may also be used, including water spray, high velocity vortex action, or natural gas. External momentum force is rarely required in ground flares. Combustion efficiency depends on flame temperature, residence time in the combustion zone, vent gas flammability, auto ignition temperature, heating value in British thermal units per standard cubic feet (Btu/scf), and turbulent mixing. These factors promote a destruction efficiency of 98 percent or greater. Complete combustion would convert all VOCs to carbon dioxide and water.

Waste gases must have a fuel value of at least 200 to 250 British thermal units per cubic foot (btu/ft³) for complete flare combustion. If a waste gas does not have the required fuel value, then fuel must be added. Flares providing supplemental fuel to waste gas are known as fired, or endothermic, flares. In some cases, even flaring waste gases having the necessary heat content will also require supplemental heat.

Flares are normally used to dispose of low volume continuous emissions, but are designed to handle large quantities of waste gases associated with plant emergencies. Flare gas volumes can vary from a few cubic meters per hour during regular operations up to several thousand cubic meters per hour during major upsets.

**PROPOSED DRAFT AMENDMENTS**

Timelines for flare minimization plans and flare monitoring and reporting have been amended to give more time to industry and the District to implement and enforce new requirements. Please see draft rule language for specific requirements and corresponding dates. The following are quick references to sections of the rule that will be amended. For detail, please see the District staff report of January 8, 2009.

*Section 1.0 Purpose*

*Section 3.0 Definitions*

*Section 5.8 Flare Minimization Requirements*

*Section 5.9 Petroleum Refinery Performance SO2 Targets*

*Section 6.2 Recordkeeping*

*Section 6.3 Testing and Sampling Methods for Flare Monitoring*

*Section 6.4 Flare Minimization Plan (FMP)*

*Section 7.0 Monitoring and Reporting Requirements*

*Section 8.0 Compliance Schedule*
4. METHODOLOGY

The socioeconomic analysis involves the use of information provided directly by affected sources, as well as secondary data used to describe the industries affected by the proposed amendments to Draft Rule 4311. The approach is briefly described below.

Applied Development Economics (ADE) began the analysis by preparing a statistical description of the industry groups of which the affected sources are a part, analyzing data on the number of jobs, sales levels, the typical profit ratios and other economic indicators for each industry.

This report relies heavily on the most current data available from a variety of sources, such as the Dun and Bradstreet, 2002 Economic Census and the State of California’s Employment Development Department (EDD) Labor Market Information Division. In addition, ADE utilized data from California Department of Conservation and the California Energy Commission. For purposes of estimating profits, ADE reviewed a number of sources, including Dun and Bradstreet, the CCH, Inc., the US Internal Revenue Services, and corporate annual reports of companies subject to Rule 4311.

With the above information, ADE was able to estimate net after tax profit ratios for sources affected by the proposed amendments. ADE calculated ratios of profit per dollar of revenue for affected industries. The result of the socioeconomic analysis shows what proportion of profits the compliance costs represent. Based on assumed thresholds of significance, ADE discusses in the report whether the affected sources are likely to reduce jobs as a means of recouping the cost of rule compliance or as a result of reducing business operations. To the extent that such job losses appear likely, the indirect multiplier effects of the jobs losses are estimated using a regional IMPLAN input-output model.

When analyzing the socioeconomic impacts of proposed new rules and amendments, ADE works closely within the parameters of accepted methodologies discussed in a 1995 California Air Resources Board report called “Development of a Methodology to Assess the Economic Impact Required by SB513/AB969” (by Peter Berck, PhD, UC Berkeley Department of Agricultural and Resources Economics, Contract No. 93-314, August, 1995). The author of this report reviewed a methodology to assess the impact that California Environmental Protection Agency proposed regulations would have on the ability of California businesses to compete. The California Air Resources Board (ARB) has incorporated the methodologies described in this report in its own assessment of socioeconomic impacts of rules generated by ARB. One methodology relates to determining a level above or below which a rule and its associated costs is deemed to have significant impacts. When analyzing the degree to which its rules are significant or insignificant, ARB employs a threshold of significance that ADE follows. Berck reviewed the threshold in his analysis and wrote, “The Air Resources Board’s (ARB) use of a 10 percent change in [Return on Equity] ROE (i.e. a change in ROE from 10 percent to a ROE of 9 percent) as a threshold for a finding of
no significant, adverse impact on either competitiveness or jobs seems reasonable or even conservative.”
5. IMPACTED INDUSTRIES SUBJECT TO PROPOSED AMENDMENTS TO DRAFT RULE 4311

This section of the socioeconomic analysis describes demographic and economic trends in the San Joaquin Valley region. The first part of this section compares the San Joaquin Valley region against California as a whole, and provides a context for understanding demographic and economic changes that occurred within the San Joaquin Valley region between 1998 and 2008. Starting with sub-section 4.2, the second part of this section narrows the focus of the socioeconomic analysis to industries affected by the proposed amendments to Draft Rule 4311. The second part of this section describes the economic characteristics of potentially impacted industries that might be subject to this rule.

5.1 REGIONAL DEMOGRAPHIC AND ECONOMIC TRENDS

REGIONAL DEMOGRAPHIC TRENDS

The San Joaquin Valley region experienced tremendous population growth during the 1990s. Many came to this area because of affordable housing. As a result, population increased significantly. The eight-county region’s population increased by 24 percent (or approximately 2.2 percent annually), from 3.2 million in 1998 to 3.9 million in 2008. In the last five years, population growth rate slightly declined, as regional population grew by 2.2 percent annually between 2003 and 2008. While the State of California’s population increased by 14 percent (or approximately 1.4 percent annually) between 1998 and 2008, all the counties in the region experienced faster rates of growth than California over the period, as Table 1 shows. While, by many standards, a small county of 150,887 residents, Madera County experienced an annual growth rate of 2.8 percent between 1998 and 2008. Between 2003 and 2008, this county continued to grow annually but at a slightly lesser rate of 2.7 percent. In the same five-year period, Kern, Merced, and San Joaquin Counties experienced rapid growth, growing annually by 2.9 percent, 2.4 percent, and 2.2 percent respectively, as Table 1 below shows. As demonstrated in the following section on regional economic trends, the demographic changes that occurred in the San Joaquin Valley region during the 1990s and into the new century significantly influenced the economy of this eight-county region.
### Regional Economic Trends

Economic development practitioners and planners have traditionally divided economies into two broad industrial categories—the economic base and local support industries. Economic base industries are the drivers of local and regional economies in that these industries draw income into a local economy by selling products outside of the local economy, much like the export industries of a national economy. Accrued earnings then circulate throughout the local area in the form of wages and salaries; investments; purchases of fixed assets, goods, and services; and generation of more jobs and wealth.

The economic base is typically comprised of industries within the manufacturing, minerals-resource extraction, and agricultural sectors. There are also the “local support industries” such as retail or service sectors, the progress of which is a function of the economic base and demographic changes, and more so the latter than the former. As population increases in a given area, demand for services—such as realtors, teachers, and healthcare—increases, as does demand for basic retail items like groceries, gas for commuting, or clothing at the local apparel shops.

Agriculture is the economic base of the San Joaquin Valley region by virtue of the amount of goods this sector produces and exports throughout the nation and the globe. Slightly less than 14 percent of all workers in the region are employed by industries within agriculture, as Table 2 shows. In 1998, approximately 13.1 percent of all workers worked in agriculture. By 2003, this ratio stood at 14 percent. In fact, over the five-year period between 2003 and 2008, employment in agriculture increased at a modest pace of one percent per year.

Between 2003 and 2008, local support industries gained in prominence within the San Joaquin Valley region. Service-rendering industries employed the most workers as a proportion of total employment in the region. Service-rendering industries comprise 71 percent of all jobs, including public sector positions. In other words, 932,713 jobs out of a total of 1,317,365 jobs are in service-rendering industries. Excluding the public sector, service-rendering jobs account for 52 percent of all jobs in 2008. In 2003, service-rendering industries (excluding the public sector) represented 51 percent of all jobs, indicating that the transition toward a services economy was in place as early as the mid to late 1990s with the significant increase in the number of people during that time.
Employment increases in service-rendering industries are consistent with regional population growth. In the region, local support industries of local and private education, and health, and financial activities increased annually by 3.9 percent, 3.0 percent, and 2.7 percent respectively between 2003 and 2008.

Construction and financial services are two other local support industries that grew in accordance with the region’s population surge; however, with the downturn in the national economy, these industries’ rates of growth have lowered dramatically. Employment in construction grew by a 6.7 percent per year in the five-year period stretching from 1998 to 2003. Between 2003 and 2008, construction continued to grow but by a slower rate of 0.9 percent per year. Likewise for financial services, which grew annually by 3.9 percent between 1998 and 2003, and has since grown by a slight 0.9 percent per year.

Close examination of Table 2 shows that the region experienced modest growth in manufacturing, as employment in this sector grew annually by 0.9 percent between 2003 and 2008. This modest increase reversed substantial declines experienced between 1998 and 2003, when manufacturing employment dropped annually by 0.6 percent. What was a regional bright spot between 1998 and 2003 (2.7 percent per year), transportation and warehousing declined annually by 1.1 percent between 2003 and 2008, as compared to the 2.7 percent annual growth in the previous five-year period.
### TABLE 2
ECOLOGIC TRENDS: SAN JOAQUIN VALLEY, 1998-2008

<table>
<thead>
<tr>
<th></th>
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<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>ALL</td>
<td>ALL</td>
<td>ALL</td>
<td>ALL</td>
</tr>
<tr>
<td></td>
<td>80,398 1,060,454 $33,566</td>
<td>92,231 1,209,849 $40,577</td>
<td>100,414 1,317,365 $39,543</td>
<td>100.0% 100.0% 2.7% 1.7%</td>
</tr>
<tr>
<td>Ag, Natural Resources</td>
<td>7,580 139,953 $18,285</td>
<td>8,646 169,556 $23,354</td>
<td>7,371 178,522 $21,714</td>
<td>13.6% 2.5% 3.9% 1.0%</td>
</tr>
<tr>
<td>Utilities</td>
<td>21 9,533 $66,831</td>
<td>213 8,340 $81,309</td>
<td>185 10,512 $82,627</td>
<td>0.8% 0.0% -2.6% 4.7%</td>
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<tr>
<td>Mining</td>
<td>22 4,231 $72,458</td>
<td>179 5,071 $86,065</td>
<td>169 5,618 $81,296</td>
<td>0.4% 0.4% 3.7% 2.1%</td>
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<tr>
<td>Construction</td>
<td>23 6,124 49,851 $38,969</td>
<td>6,074 69,065 $46,870</td>
<td>6,705 72,312 $44,716</td>
<td>5.5% 5.7% 6.7% 0.9%</td>
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<tr>
<td>Manufacturing</td>
<td>31-33 2,998 113,344 $40,989</td>
<td>2,799 110,002 $48,735</td>
<td>2,662 115,153 $43,352</td>
<td>8.7% 9.3% -0.6% 0.9%</td>
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<tr>
<td>Wholesale</td>
<td>42 2,749 33,365 $47,726</td>
<td>2,722 37,124 $53,053</td>
<td>3,027 45,299 $46,510</td>
<td>3.4% 4.6% 2.2% 4.1%</td>
</tr>
<tr>
<td>Retail</td>
<td>44-45 9,586 121,132 $26,446</td>
<td>8,941 132,956 $31,349</td>
<td>8,882 143,910 $25,892</td>
<td>10.9% 10.8% 1.9% 1.6%</td>
</tr>
<tr>
<td>Transport Warehousing</td>
<td>48-49 2,306 33,821 $38,946</td>
<td>2,237 38,554 $44,962</td>
<td>1,957 36,514 $40,166</td>
<td>2.8% 2.7% 2.7% -1.1%</td>
</tr>
<tr>
<td>Information</td>
<td>51 653 14,885 $43,401</td>
<td>692 14,257 $53,695</td>
<td>625 15,328 $47,417</td>
<td>1.2% 3.0% -0.9% 1.5%</td>
</tr>
<tr>
<td>Finance and Insurance</td>
<td>52 2,637 27,792 $46,709</td>
<td>3,046 30,690 $59,530</td>
<td>3,373 32,027 $50,112</td>
<td>2.4% 4.0% 2.0% 0.9%</td>
</tr>
<tr>
<td>Real Estate</td>
<td>53 2,575 13,180 $26,755</td>
<td>2,607 15,932 $34,144</td>
<td>2,784 15,897 $32,633</td>
<td>1.2% 1.8% 3.9% 0.0%</td>
</tr>
<tr>
<td>Prof Technical Services</td>
<td>54 4,064 25,130 $44,216</td>
<td>4,501 31,812 $52,467</td>
<td>4,839 36,411 $46,773</td>
<td>2.9% 6.8% 4.8% 2.7%</td>
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<tr>
<td>Management of Companies</td>
<td>55 321 17,997 $52,338</td>
<td>316 13,988 $60,045</td>
<td>288 10,551 $55,323</td>
<td>0.8% 1.3% -4.9% -5.5%</td>
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<tr>
<td>Admn and Waste Services</td>
<td>56 2,910 44,283 $22,362</td>
<td>2,768 48,182 $28,986</td>
<td>2,947 50,761 $27,165</td>
<td>4.5% 6.4% 1.7% 4.0%</td>
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<td>Private Educational Services</td>
<td>61 459 7,107 $25,456</td>
<td>480 9,298 $29,532</td>
<td>497 10,781 $27,407</td>
<td>0.8% 1.7% 5.5% 3.0%</td>
</tr>
<tr>
<td>Health Services</td>
<td>62 6,082 90,304 $38,243</td>
<td>6,526 110,647 $47,867</td>
<td>6,983 126,598 $44,058</td>
<td>9.6% 8.8% 4.1% 2.7%</td>
</tr>
<tr>
<td>Arts, Entertainment, Rec</td>
<td>71 617 10,386 $16,985</td>
<td>621 10,244 $20,192</td>
<td>641 11,172 $17,365</td>
<td>0.8% 1.6% -0.3% 1.7%</td>
</tr>
<tr>
<td>Food and Accomodations</td>
<td>72 5,050 70,335 $12,860</td>
<td>4,942 78,805 $15,831</td>
<td>5,312 90,404 $14,020</td>
<td>6.9% 8.3% 2.3% 2.8%</td>
</tr>
<tr>
<td>Other Services</td>
<td>81 20,157 41,069 $21,165</td>
<td>30,390 47,370 $25,731</td>
<td>35,629 52,505 $21,606</td>
<td>4.0% 4.6% 2.9% 2.1%</td>
</tr>
<tr>
<td>Unclassified</td>
<td>99 85 199 $38,033</td>
<td>1,769 2,534 $26,836</td>
<td>0.2% 0.3% 3.4% 2.4%</td>
<td></td>
</tr>
<tr>
<td>Local Govt.</td>
<td>409 51,325 $45,674</td>
<td>437 60,768 $56,307</td>
<td>477 68,469 $51,051</td>
<td>5.2% 5.2% 3.4% 2.4%</td>
</tr>
<tr>
<td>Local Govt., Education</td>
<td>881 90,200 $39,664</td>
<td>1,487 109,087 $48,304</td>
<td>1,792 118,716 $78,718</td>
<td>9.0% 5.9% 3.9% 1.7%</td>
</tr>
<tr>
<td>State, ALL</td>
<td>1,464 23,639 $46,051</td>
<td>1,166 28,463 $56,515</td>
<td>1,078 31,639 $51,222</td>
<td>2.4% 2.9% 3.8% 2.1%</td>
</tr>
<tr>
<td>Federal, ALL</td>
<td>360 27,592 $52,749</td>
<td>376 29,439 $66,395</td>
<td>424 27,732 $58,945</td>
<td>2.1% 1.6% 1.3% -1.2%</td>
</tr>
</tbody>
</table>

Source: ADF, Inc., based on California Employment Development Department, LBMID
5.2 DESCRIPTION OF AFFECTED INDUSTRIES

Whereas the previous section described the larger economic context within which the District is contemplating proposed amendments to Rule 4311, this section analyzes trends of industries directly affected by the proposed amendments. For the most part, this rule affects petroleum refineries and oil producers in the region. The discussion directly below examines trends with respect to these industries in the San Joaquin Valley region, including data on an annual basis for a five-year period starting in 2003.

According to the California Employment Development Department (EDD), 32 oil refineries are currently operating in the eight-county region, an amount that according to the EDD has not changed when compared to 2003. Close inspection of EDD’s data indicates that only four are actual refineries. The four refineries are Big West (66,000 barrels per day), Kern Oil Refining (26,000 barrels per day), San Joaquin Refining (15,000 barrels per day), and Tricor. At the moment, Tricor is not operating its refinery, although Tricor continues to offer other petroleum-related services. Tricor still maintains a permit to operate its refinery. Kern Oil and San Joaquin Refining are considered small refineries.

The number of workers employed by the three operating oil refineries in the region increased by three percent annually between 2003 and 2008, going from 549 to 637. Average wages tend to be very high in this industry, at an estimated $98,900 in 2008, up from the 2003 average of $76,300. Table 3 below also includes revenue trends estimates. Oil refineries in the region generated an estimated $3.1 billion in revenues in 2008, which is approximately $592,100,400 more than what was generated in 2003. On average, the three operating refineries generate $1,049,600,700 in revenues, versus the $511,300,200 average in 2003.

TABLE 3
EDD OIL REFINERY TRENDS: SAN JOAQUIN VALLEY REGION

<table>
<thead>
<tr>
<th>Region</th>
<th>2003</th>
<th>2004</th>
<th>2005</th>
<th>2006</th>
<th>2007</th>
<th>2008</th>
<th>Change 03-08</th>
<th>Annual Percent Change 03-08</th>
</tr>
</thead>
<tbody>
<tr>
<td>Establishments</td>
<td>32</td>
<td>29</td>
<td>32</td>
<td>31</td>
<td>32</td>
<td>32</td>
<td>0</td>
<td>-0.3%</td>
</tr>
<tr>
<td>Actual Refineries</td>
<td>5</td>
<td>5</td>
<td>5</td>
<td>5</td>
<td>5</td>
<td>4</td>
<td>-1</td>
<td>-4%</td>
</tr>
<tr>
<td>Small Refineries</td>
<td>3</td>
<td>3</td>
<td>3</td>
<td>3</td>
<td>3</td>
<td>2</td>
<td>-1</td>
<td>-20%</td>
</tr>
<tr>
<td>Employment</td>
<td>549</td>
<td>647</td>
<td>587</td>
<td>579</td>
<td>626</td>
<td>637</td>
<td>88</td>
<td>3%</td>
</tr>
<tr>
<td>Payroll ($2008)</td>
<td>$54,845,080</td>
<td>$81,177,515</td>
<td>$66,383,607</td>
<td>$71,047,731</td>
<td>$83,006,037</td>
<td>$82,445,713</td>
<td>$27,600,633</td>
<td>8.5%</td>
</tr>
<tr>
<td>Average Pay ($2008)</td>
<td>$76,287</td>
<td>$95,832</td>
<td>$96,317</td>
<td>$93,777</td>
<td>$101,405</td>
<td>$98,879</td>
<td>$22,591</td>
<td>5.3%</td>
</tr>
<tr>
<td>Annual output</td>
<td>37,277,284</td>
<td>37,220,213</td>
<td>37,589,558</td>
<td>37,822,866</td>
<td>37,953,878</td>
<td>30,025,891</td>
<td>-7,251,393</td>
<td>-19.5%</td>
</tr>
</tbody>
</table>


Source: ADE, Inc., based on US Economic Census, California EDD LMID, and California Department of Conservation

1District staff and ADE reviewed a list of companies prepared by the EDD that included the 32 refineries, and determined that, while most of these businesses are in petroleum-related businesses, most are not refineries. There are only four refineries in the region right now.
Proposed amendments to Rule 4311 also affect oil producers. In 2008, oil prices spiked up tremendously, resulting in significant amount of revenues for this industry. In 2008, oil producers generated $14.3 billion, almost triple what they generated in 2003, or $5.7 billion. To control for 2008, we calculated a three year average for 2005-2008 period. Over this period, oil producers average $11.8 billion. As Table 4 shows, there are 52 oil producers operating in the eight-county region, and these businesses employ slightly over 2,700 workers.

Table 5 below also includes estimates on revenues generated by large and small oil producers, or $9.9 billion and $1.8 billion respectively. Large oil producers generate, on average, $1.9 billion in revenues, versus the $38,800,000 in revenues generated by small oil producers. Based on throughput capacity of each refinery (assuming an 80 percent operating capacity), we estimate that the three operating refineries generate $2.6 billion in aggregate revenues, as well as $168,900,700 in after-tax net-profits.

What is driving the increase in revenues in oil production and refining is the significant increase in oil price on a per barrel basis. In the five-year period between 2003 and 2008, the monthly price of crude oil in California averaged approximately $55.00 per barrel (see Figure 1). Since January 2007, the monthly average has been above the medium-term average, having spiked up significantly in the spring of 2008. The price of crude oil in California has declined significantly since early fall, and, at $35.05 per barrel in December 2008, has fallen below the 2003-2008 average. It is important to note...
that the price of oil is set on the world market, not locally or regionally. A variety of factors influence the price of oil in California, including energy demand from fast-growing economies such as the People’s Republic of China and India, amount of reserves available on the world market, national and global economic climate, global political unrest, and relative availability of alternative sources of energy, to name a few factors.
FIGURE 1
MONTHLY CRUDE OIL PRICE (PRICE PER BARREL)

Source: ADE, Inc., California Department of Conservation
It is interesting to note that Central Valley oil producers responded to the surge in oil prices by opening up more wells (see Figure 2). Despite this effort to supply the market, oil producers experienced declining oil production in aggregate (see Figure 3), which is partly explained by Figure 4, which traces a declining output per producing well. Thus, data suggest that newer wells are not producing as much oil as older wells, which, for their part, could be experiencing declining output as well.

Figure 5 translates the per barrel price of crude oil into per gallon terms, and compares these prices against wholesale price of refined gasoline and price of reformulated gasoline as sold by gas station. What is even more interesting about this figure are differences between per gallon price of crude oil and the per gallon wholesale price of gasoline, and the per gallon wholesale price and per gallon price of reformulated gasoline sold at gas stations. Expressed in dollar per gallon terms, gross margins of the oil refineries tend to be higher than gross margins for gas station, reinforcing anecdotal information that suggests gasoline stations do not necessarily benefit when oil producers and oil refineries are doing well. For example, at its peak in June 2008, gas stations sold reformulated gas at $4.36 per gallon after having purchased the gas from refineries and distributors for $3.56 per gallon, for a gross margin of $0.80 per gallon. Refineries purchased crude oil at approximately $2.23 per gallon and then sold the refined product at $3.56 per gallon, for a gross margin of $1.33 per gallon.
FIGURE 2
MONTHLY TRENDS IN NUMBER OF PRODUCING WELL
JANUARY 2000 THROUGH NOVEMBER 2008

Source: ADE, Inc., California Department of Conservation
FIGURE 3
MONTHLY CRUDE OIL PRODUCTION
JANUARY 2000 THROUGH NOVEMBER 2008

Source: ADE, Inc., California Department of Conservation
FIGURE 4
MONTHLY OIL PRODUCTION (BBL) BY PRODUCING WELLS
JANUARY 2000 THROUGH NOVEMBER 2008

Source: ADE, Inc., California Department of Conservation
SAN JOAQUIN VALLEY UNIFIED AIR POLLUTION CONTROL DISTRICT

Appendix D: Socioeconomic Impact Analysis

June 18, 2009

FIGURE 5
COMPARISON OF CALIFORNIA MONTHLY PRICE PER GALLON: CRUDE OIL, REFINED OIL, AND REGULAR REFORMULATED GASOLINE, JANUARY 2000 THROUGH DECEMBER 2008

Source: ADE, Inc., California Department of Conservation
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6. SOCIO-ECONOMIC IMPACTS

This section of the report compares the economic characteristics of affected industries against the annual compliance costs. The first part of this section discusses annual compliance costs. Section 6.2 discusses general business responses to compliance costs. Section 6.3 analyzes the socioeconomic impacts of the proposed amendments to Rules 4311.

6.1 COMPLIANCE COST ESTIMATES

Table 6 summarizes the estimated annualized costs associated with proposed amendments to Rule 4311. The table includes cost estimates issued by the District and industry stakeholders. As the table shows, the District indicates that impacted sources will bear $920,000 in total capital costs, which, when annualized, translates into an annual cost of $239,652, which includes cost of personnel. Industry stakeholders in the refining industry place total cost per establishment at $8,500,000, which, when annualized, amounts to $1,671,245.

| Source: San Joaquin Valley Unified Air Pollution Control District and Kern Oil | Big West |
| Capital Cost Per Establishment | Annual Cost Per Establishment |
| Air District | $920,000 | $239,652 |
| Industry Stakeholders (petroleum industries only) | $8,500,000 | $1,671,245 |

6.2 BUSINESS RESPONSES TO COMPLIANCE COSTS

Industries impacted by the proposed amendments may respond in a variety of ways when faced with new regulatory costs. These responses may range from simply absorbing the costs and accepting a lower rate of return, to shutting down the affected business operation altogether and, where practical, shift from lower-value to higher-value product and or service. Impacted industries might also seek to pass costs to users of services or purchasers of goods, depending on the magnitude of costs and on what the overall market can bear. Affected sources may also seek to renew efforts to increase productivity and reduce costs elsewhere in their operation in order to recoup the regulatory costs and maintain profit levels. More than likely, industries impacted by amendments to Rule 4311 will pass costs to consumers and commercial\industrial entities needing fuel, which is to say most industries.

6.3 IMPACTS ON AFFECTED INDUSTRIES

This section of the report analyzes estimated after tax net profits of affected industries against anticipated costs associated with implementation of proposed amendments to Rule 4311. As Table 7 below indicates, impacts to petroleum-related industries including refineries and oil producers are less than significant. Small oil producers\oil field services are also not disproportionately impacted by proposed amendments to Rule 4311. In addition to oil-related industries, a number of other industries are also potentially impacted by the proposed amendments. Table 8 below shows that, for
the most part, impacts are less than significant. A fruit juice manufacturer – Odwalla – is potentially significantly impacted by the rule, as estimated annual impacts of $239,700 exceed the ten-percent threshold, or $180,210, by $59,440. Recouping that amount above the ten-percent threshold through workforce reduction would amount to 1.4 full-time equivalent positions, or under one percent of the estimated plant workforce. However, we conclude that Odwalla is not significantly impacted because, more than likely, the 1.4 FTE impact falls within normal job attrition that occurs at the Odwalla plant in Dinuba. Thus, we conclude by saying that proposed amendments to Rule 4311 does not significantly impact industries, nor are small businesses disproportionately impacted by the proposed amendments.
# Table 7
## Socioeconomic Impact Analysis: Draft Rule 4311: Petroleum, Natural Gas Related Industries

<table>
<thead>
<tr>
<th></th>
<th>Large Refineries</th>
<th>Small Refineries</th>
<th>Large Oil/Natural Gas Producers</th>
<th>Small Oil Producers/Oil Field Services</th>
<th>Others</th>
</tr>
</thead>
<tbody>
<tr>
<td>Establishments</td>
<td>1</td>
<td>2</td>
<td>5</td>
<td>50</td>
<td>4</td>
</tr>
<tr>
<td>Revenues</td>
<td>$1,623,057,093</td>
<td>$1,008,262,739</td>
<td>$9,961,618,081</td>
<td>$1,806,286,727</td>
<td>$124,567,646</td>
</tr>
<tr>
<td>Net Profits</td>
<td>$104,200,266</td>
<td>$64,730,468</td>
<td>$1,038,000,604</td>
<td>$188,215,077</td>
<td>$12,979,949</td>
</tr>
<tr>
<td>Total Annual Costs: District Scenario</td>
<td>$239,652</td>
<td>$479,304</td>
<td>$1,198,260</td>
<td>$11,982,600</td>
<td>$958,608</td>
</tr>
<tr>
<td>Total Annual Costs: Industry Stakeholder Scenario</td>
<td>$1,671,245</td>
<td>$3,342,490</td>
<td>$8,356,225</td>
<td>$83,562,250</td>
<td>$6,684,980</td>
</tr>
<tr>
<td>Cost to Net Profit Ratio: District Scenario</td>
<td>0.23%</td>
<td>0.74%</td>
<td>0.12%</td>
<td>6.37%</td>
<td>7.39%</td>
</tr>
<tr>
<td>Cost to Net Profit Ratio: Industry Stakeholder Scenario</td>
<td>1.60%</td>
<td>5.16%</td>
<td>0.81%</td>
<td>NA</td>
<td>NA</td>
</tr>
<tr>
<td>District Scenario Significance</td>
<td>less than significant</td>
<td>less than significant</td>
<td>less than significant</td>
<td>less than significant</td>
<td>less than significant</td>
</tr>
<tr>
<td>Industry Stakeholder Scenario Significance</td>
<td>less than significant</td>
<td>less than significant</td>
<td>less than significant</td>
<td>less than significant</td>
<td>NA</td>
</tr>
</tbody>
</table>

Source: ADE, Inc., based on US Economic Census, SJVUAPCD, California Department of Conservation, and California Energy Commission

# Table 8
## Socioeconomic Impact Analysis: Draft Rule 4311: Industries Other Than Petroleum/Natural Gas

<table>
<thead>
<tr>
<th></th>
<th>Dairy Farms</th>
<th>Frozen Fruits, Fruit Juices Manufacturing</th>
<th>Flat Glass Manufacturing</th>
<th>Industrial Organic Chemicals</th>
<th>Sewerage Systems</th>
<th>Other Public</th>
</tr>
</thead>
<tbody>
<tr>
<td>Establishments</td>
<td>3</td>
<td>1</td>
<td>1</td>
<td>1</td>
<td>1</td>
<td>9</td>
</tr>
<tr>
<td>Revenues</td>
<td>$555,813,005</td>
<td>$34,292,958</td>
<td>$134,062,280</td>
<td>$70,105,071</td>
<td>$213,607,700</td>
<td>$318,000,000</td>
</tr>
<tr>
<td>Net Profits</td>
<td>$61,695,244</td>
<td>$1,802,096</td>
<td>$5,174,021</td>
<td>$3,166,035</td>
<td>$213,607,700</td>
<td>$318,000,000</td>
</tr>
<tr>
<td>Total Annual Costs: District Scenario</td>
<td>$718,956</td>
<td>$239,652</td>
<td>$239,652</td>
<td>$239,652</td>
<td>$2,156,868</td>
<td>$479,304</td>
</tr>
<tr>
<td>Cost to Net Profit Ratio: District Scenario</td>
<td>1.17%</td>
<td>13.30%</td>
<td>4.63%</td>
<td>7.57%</td>
<td>1.01%</td>
<td>0.15%</td>
</tr>
<tr>
<td>District Scenario Significance</td>
<td>less than significant</td>
<td>significant</td>
<td>less than significant</td>
<td>less than significant</td>
<td>less than significant</td>
<td>less than significant</td>
</tr>
</tbody>
</table>

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APPENDIX E

Rule Consistency Analysis
For
Revised Proposed Amendments to Rule 4311

June 18, 2009
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APPENDIX E
Rule Consistency Analysis

I. REQUIREMENTS OF ANALYSIS

Pursuant to Section 40727.2 of the California Health and Safety Code, prior to adopting, amending, or repealing a rule or regulation, the District is required to perform a written analysis that identifies and compares the air pollution control elements of the rule or regulation with corresponding elements of existing or proposed District and United States Environmental Protection Agency (EPA) rules, regulations, and guidelines that apply to the same source category. The elements that were analyzed are emission standards, monitoring and testing, and recordkeeping and reporting requirements.

II. RULE CONSISTENCY ANALYSIS

A. District Rules

Facilities could be subject to other District rules including:

- Rule 1070 Inspections
- Rule 1080 Stack Monitoring
- Rule 1100 Equipment Breakdown
- Rule 2010 Permits Required
- Rule 2201 New and Modified Stationary Source Review Rule
- Rule 2520 Federally Mandated Operating Permits
- Rule 4001 New Source Performance Standards
- Rule 4101 Visible Emissions
- Rule 4102 Nuisance
- Rule 4201 Particulate Matter Concentration
- Rule 4202 Particulate Matter Emission Rate
- Rule 4451 Valves, Pressure Release Valves, Flanges, Threaded Connections and Process Drains at Petroleum Refineries and Chemical Plants
- Rule 4452 Pump and Compressor Seals at Petroleum Refineries and Chemical Plants
- Rule 4454 Refinery Process Unit Turnaround
- Rule 4801 Sulfur Compounds

The above-listed rules are not in conflict with, nor are they inconsistent with the requirements of Proposed Rule 4311.
B. Federal EPA Rules and Regulations

1. Federal Control Techniques Guideline (CTG)

There is no EPA CTG for flares.

2. Alternative Control Technology (ACT)

There is no EPA ACT for flares.

3. Federal New Source Performance Standards (NSPS)

40 CFR 60.18 (General Control Device Requirements) and 40 CFR 65.147 (Flares)

40 CFR 60.18 specifies certain minimum equipment performance standards for equipment used as control devices. In the case of flares, the CFR specifies no visible emission as well as certain equipment standards. Since NOx and VOC are invisible gasses, this portion of the CFR does not identify RACT for flares. 40 CFR 65.147 is part of the federal consolidated air rule. It essentially echoes 40 CFR 60.18 and as such does not identify RACT for flares.

4. National Emission Standards for Hazardous Air Pollutants (NESHAPs) and Maximum Achievable Performance Standards (MACTs)

There is no NESHAP or MACT for flares.

5. EPA Policy on Recordkeeping

The recordkeeping requirement in Rule 4311 is consistent with EPA’s policy to keep and maintain records for at least five years.

III. CONCLUSION

Based on the above analysis, District staff concludes that Proposed Rule 4311 satisfies RACT for flaring operations in terms of emission limits and equipment standards.