

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[EPA-HQ-OAR-2007-0011; FRL-8753-5]

RIN 2060-AN72

Standards of Performance for Petroleum Refineries; Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: On June 24, 2008, EPA promulgated amendments to the Standards of Performance for Petroleum Refineries and new standards for process units constructed, reconstructed, or modified after May 14, 2007. EPA received three petitions for reconsideration of the final rule. On September 26, 2008, EPA granted reconsideration and issued a stay for the issues raised in the petitions regarding process heaters and flares. In this action, EPA is addressing those specific issues by proposing amendments to certain provisions for process heaters and flares. EPA is also proposing various technical corrections in this action that were raised in the petitions for reconsideration. EPA will take action on other issues raised by Petitioners in future notices.

DATES: Comments must be received on or before February 5, 2009.

Public Hearing. If anyone contacts EPA requesting to speak at a public hearing by January 2, 2009 public hearing will be held on January 6, 2009.

ADDRESSES: Submit your comments, identified by Docket ID No. EPA-HQ-OAR-2007-0011, by one of the following methods:

- *www.regulations.gov*: Follow the on-line instructions for submitting comments.

- *E-mail:* a-and-r-Docket@epa.gov, Attention Docket ID No. EPA-HQ-OAR-2007-0011.

- *Fax:* (202) 566-9744, Attention Docket ID No. EPA-HQ-OAR-2007-0011.

- *Mail:* Air and Radiation Docket and Information Center, Environmental Protection Agency, Mailcode: 2822T, 1200 Pennsylvania Ave., NW., Washington, DC 20460, Attention Docket ID No. EPA-HQ-OAR-2007-0011. Please include a total of two copies.

- *Hand Delivery or Courier:* EPA Docket Center (2822T), 1301 Constitution Avenue, NW., Room 3334, Washington, DC 20004, Attention Docket ID No. EPA-HQ-OAR-2007-0011. Such deliveries are only accepted during the Docket's normal hours of operation, and special arrangements should be made for deliveries of boxed information. Please include a total of two copies.

Instructions: Direct your comments to Docket ID No. EPA-HQ-OAR-2007-0011. EPA's policy is that all comments received will be included in the public docket without change and may be made available online at *www.regulations.gov*, including any personal information provided, unless the comment includes information claimed to be confidential business information (CBI) or other information whose disclosure is restricted by statute. Do not submit information that you consider to be CBI or otherwise protected through *www.regulations.gov* or e-mail. The *www.regulations.gov* Web site is an "anonymous access" system, which means EPA will not know your identity or contact information unless you provide it in the body of your comment. If you send an e-mail comment directly to EPA without going through *www.regulations.gov*, your e-mail address will be automatically captured and included as part of the comment that is placed in the public docket and made available on the Internet. If you submit an electronic

comment, EPA recommends that you include your name and other contact information in the body of your comment and with any disk or CD-ROM you submit. If EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, EPA may not be able to consider your comment. Electronic files should avoid the use of special characters, any form of encryption, and be free of any defects or viruses.

Docket: All documents in the docket are listed in the *www.regulations.gov* index. Although listed in the index, some information is not publicly available, e.g., CBI or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, will be publicly available only in hard copy. Publicly available docket materials are available either electronically in *www.regulations.gov* or in hard copy at the EPA Docket Center, Standards of Performance for Petroleum Refineries Docket, EPA West Building, Room 3334, 1301 Constitution Ave., NW., Washington, DC. The Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566-1744, and the telephone number for the Docket Center is (202) 566-1742.

FOR FURTHER INFORMATION CONTACT: Mr. Robert B. Lucas, Office of Air Quality Planning and Standards, Sector Policies and Programs Division, Coatings and Chemicals Group (E143-01), Environmental Protection Agency, Research Triangle Park, NC 27711, telephone number: (919) 541-0884; fax number: (919) 541-0246; e-mail address: lucas.bob@epa.gov.

SUPPLEMENTARY INFORMATION:

I. General Information

A. Does this action apply to me?

Categories and entities potentially regulated by this proposed rule include:

Category	NAICS code ¹	Examples of regulated entities
Industry	32411	Petroleum refiners.
Federal government		Not affected.
State/local/tribal government		Not affected.

¹ North American Industry Classification System.

This table is not intended to be exhaustive, but rather provides a guide for readers regarding entities likely to be regulated by this action. To determine whether your facility would be regulated by this action, you should

examine the applicability criteria in 40 CFR 60.100 and 40 CFR 60.100a. If you have any questions regarding the applicability of this proposed action to a particular entity, contact the person

listed in the preceding **FOR FURTHER INFORMATION CONTACT** section.

B. What should I consider as I prepare my comments to EPA?

Do not submit information containing CBI to EPA through www.regulations.gov or e-mail. Send or deliver information identified as CBI only to the following address: Roberto Morales, OAQPS Document Control Officer (C404-02), Office of Air Quality Planning and Standards, Environmental Protection Agency, Research Triangle Park, NC 27711, Attention Docket ID No. EPA-HQ-OAR-2007-0011. Clearly mark the part or all of the information that you claim to be CBI. For CBI information in a disk or CD-ROM that you mail to EPA, mark the outside of the disk or CD-ROM as CBI and then identify electronically within the disk or CD-ROM the specific information that is claimed as CBI. In addition to one complete version of the comment that includes information claimed as CBI, a copy of the comment that does not contain the information claimed as CBI must be submitted for inclusion in the public docket. Information so marked will not be disclosed except in accordance with procedures set forth in 40 CFR part 2.

C. Where can I get a copy of this document?

In addition to being available in the docket, an electronic copy of this proposed action is available on the Worldwide Web (WWW) through the Technology Transfer Network (TTN). Following signature, a copy of this proposed action will be posted on the TTN's policy and guidance page for newly proposed or promulgated rules at <http://www.epa.gov/ttn/oarpg>. The TTN provides information and technology exchange in various areas of air pollution control.

D. When would a public hearing occur?

If anyone contacts EPA requesting to speak at a public hearing by January 2, 2009, a public hearing will be held on January 6, 2009. Persons interested in presenting oral testimony or inquiring as to whether a public hearing is to be held should contact Mr. Bob Lucas, listed in the **FOR FURTHER INFORMATION CONTACT** section, at least 2 days in advance of the hearing. If a public hearing is held, it will be held at 10 a.m. at the EPA's Environmental Research Center Auditorium, Research Triangle Park, NC, or an alternate site nearby.

E. How is this document organized?

The supplementary information presented in this preamble is organized as follows:

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II. Background Information

A. Why are we proposing these amendments?

Standards of performance for petroleum refineries were promulgated on June 24, 2008 that included: (1) Final amendments to the existing petroleum refineries new source performance standards (NSPS) in 40 CFR part 60, subpart J; and (2) a new petroleum refineries NSPS in 40 CFR part 60, subpart Ja (73 FR 35838). On June 13,

2008, the American Petroleum Institute (API), the National Petrochemical and Refiners Association (NPRA), and the Western States Petroleum Association (WSPA) (collectively referred to as "Industry Petitioners") requested an administrative stay under Clean Air Act (CAA) section 307(d)(7)(B) of certain provisions of 40 CFR part 60, subpart Ja (Docket Item EPA-HQ-OAR-2007-0011-245). On July 25, 2008, the Industry Petitioners sought reconsideration of the provisions of 40 CFR part 60, subpart Ja for which they had previously requested a stay (Docket Item EPA-HQ-OAR-2007-0011-267). Specifically, Industry Petitioners requested that EPA reconsider the following provisions in subpart Ja: (1) The newly promulgated definition of "modification" for flares (40 CFR 60.100a(c)); (2) the definition of "flare" (40 CFR 60.101a); (3) the fuel gas combustion device sulfur limits as they relate to flares (40 CFR 60.102a(g)(1)); (4) the flow limit for flares (40 CFR 60.102a(g)(3)); (5) the total reduced sulfur and flow monitoring requirements for flares (40 CFR 60.107a(d) and (e)); and (6) the nitrogen oxide (NO_x) limit for process heaters (40 CFR 60.102a(g)(2)). Subsequently, on August 21, 2008, Industry Petitioners identified additional issues for reconsideration (Docket Item EPA-HQ-OAR-2007-0011-246). Industry Petitioners identified a number of issues with the standards for fluid catalytic cracking units (FCCU), fluid coking units (FCU), fuel gas combustion devices, sulfur recovery plants, and delayed coking units. The issues ranged from disagreeing with the best demonstrated technology (BDT) analyses for FCCU/FCU and delayed coking units to requests for clarification of requirements regarding averaging times for various limits, to identifying inconsistencies in compliance methods, to simple typographical errors. A total of 82 items were identified in this submittal.

On August 25, 2008, HOVENSA, LLC ("HOVENSA") filed a petition for reconsideration of the following provisions of 40 CFR part 60, subpart Ja: (1) The NO_x limit for process heaters (40 CFR 60.102a(g)(2)); (2) the flaring requirements, including the definitions of "flare" and "modification" (40 CFR 60.100a(c), 60.101a, 60.102a(g) through (i), 60.103a(a) and (b)); and (3) the depressurization work practice standard for delayed coking units (40 CFR 60.103a(c)) (Docket Item No. EPA-HQ-OAR-2007-0011-247). The petition also requested that EPA stay the

effectiveness of these provisions during the reconsideration process.

EPA received a third petition for reconsideration on August 25, 2008, from the Environmental Integrity Project, Sierra Club, and Natural Resources Defense Council ("Environmental Petitioners") requesting that EPA reconsider several aspects of 40 CFR part 60, subpart Ja (Docket Item No EPA-HQ-OAR-2007-0011-243). The petition identified the following issues for reconsideration: (1) EPA's decision not to promulgate standards for carbon dioxide (CO₂) and methane emissions from refineries; (2) the flaring requirements (40 CFR 60.100a(c), 60.101a, 60.102a(g) through (i), 60.103a(a) and (b)); (3) the NO_x limit for FCCU (40 CFR 60.102a(b)(2)); and (4) the particulate matter (PM) limit for FCCU (40 CFR 60.102a(b)(1)). Unlike the other Petitioners, Environmental Petitioners did not seek a stay of these provisions during reconsideration.

On September 26, 2008, EPA issued a **Federal Register** notice (73 FR 55751) granting reconsideration of the following issues: (1) The newly promulgated definition of "modification" for flares; (2) the definition of "flare;" (3) the fuel gas combustion device sulfur limits as they apply to flares; (4) the flow limit for flares; (5) the total reduced sulfur and flow monitoring requirements for flares; and (6) the NO_x limit for process heaters. EPA also granted Industry Petitioners' and HOVENSA's request for a 90-day stay for those same provisions under reconsideration. In this action, EPA is addressing those issues for which it granted reconsideration and a stay as outlined in the September 26 notice. We are also addressing certain other minor issues raised by Industry Petitioners in this action, as discussed later in this preamble; we will take action on all of the remaining issues raised by the Petitioners for reconsideration in future notices.

B. What is the statutory authority for the proposed amendments?

New source performance standards implement CAA section 111(b) and are issued for categories of sources which cause, or contribute significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare. The primary purpose of the NSPS is to attain and maintain ambient air quality by ensuring that the best demonstrated emission control technologies are installed as the industrial infrastructure is modernized. Since 1970, the NSPS have been successful in achieving long-term emissions reductions in numerous

industries by assuring cost-effective controls are installed on newly constructed, reconstructed, or modified sources.

Section 111 of the CAA requires that NSPS reflect the application of the best system of emission reductions which (taking into consideration the cost of achieving such emission reductions, any non-air quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated. This level of control is commonly referred to as best demonstrated technology (BDT). CAA section 111 also authorizes EPA to distinguish among classes, types, and sizes within categories of sources when establishing standards.

Section 111(b)(1)(B) of the CAA requires EPA to periodically, but no later than every 8 years, review and revise the standards of performance, as necessary, to reflect improvements in methods for reducing emissions.

C. What are the current petroleum refinery NSPS that are proposed to be amended?

NSPS for petroleum refineries (40 CFR part 60, subpart J) apply to the affected facilities at the refinery, such as fuel gas combustion devices (which include process heaters and flares), that commence construction, reconstruction, or modification after June 11, 1973. The NSPS were originally promulgated on March 8, 1974, and have been amended several times. In this action, we are granting reconsideration and proposing technical corrections to subpart J for certain issues that were identified by Industry Petitioners.

Additional standards for petroleum refineries (40 CFR part 60, subpart Ja) apply to flares that commence construction, reconstruction, or modification after June 24, 2008, and other affected petroleum refinery sources, including process heaters, that commence construction, reconstruction, or modification after May 14, 2007. In this action, we are proposing amendments to subpart Ja to address the issues raised by Petitioners regarding flares and process heaters. We are also granting reconsideration and proposing technical corrections to subpart Ja for certain issues that were identified by Industry Petitioners.

III. Summary of the Proposed Amendments

The following sections summarize the proposed amendments in both 40 CFR part 60, subpart J and 40 CFR part 60, subpart Ja. Section IV contains the rationale for these amendments, while

the amendments themselves follow the preamble.

A. What are the proposed amendments to the existing standards for petroleum refineries in 40 CFR part 60, subpart J?

We are proposing to add a new paragraph to 40 CFR 60.100 to allow 40 CFR part 60, subpart J affected sources the option of complying with subpart J by following the requirements in 40 CFR part 60, subpart Ja. We believe the subpart Ja requirements are at least as stringent as those in subpart J, so providing this option will allow all process units in a refinery to follow the same requirements and simplify compliance. We request comments on this allowance. We are also proposing to correct the value and units (in the metric system) for the allowable incremental rate of PM emissions in 40 CFR 60.106(c)(1). We amended the units for this constant in 40 CFR 60.102(b) on June 24, 2008, and we are now correcting 40 CFR 60.106(c)(1) accordingly.

B. What are the proposed amendments to the new requirements for affected process heaters in 40 CFR part 60, subpart Ja?

We are proposing to create three subcategories of process heaters and to establish performance standards for NO_x emissions within these subcategories for new, modified, and reconstructed process heaters. The subcategories that we are proposing to create are: (1) Natural draft process heaters; (2) forced draft process heaters; and (3) co-fired process heaters. We are also proposing to provide an additional emission limit format for these subcategories, to extend the averaging time over which compliance is determined, and to allow additional options for demonstrating initial and ongoing compliance with the limits. Other aspects of the final rule, such as recordkeeping and reporting requirements, remain the same, and will apply as promulgated to all of these subcategories.

For the natural draft process heater subcategory, the proposed NO_x emission limit for newly constructed, modified, and reconstructed natural draft process heaters is 40 parts per million by volume (ppmv) on a 365-day rolling average basis (dry at 0 percent excess air). For the second subcategory, forced draft process heaters, the proposed NO_x emission limit for newly constructed forced draft process heaters is 40 ppmv on a 365-day rolling average basis (dry at 0 percent excess air). For modified or reconstructed forced draft process heaters, the proposed NO_x

emission limit is 60 ppmv on a 365-day rolling average basis (dry at 0 percent excess air). These limits are based on the performance of ultra-low NO_x burner control technologies.

We are also proposing an alternative compliance option that would allow owners and operators to obtain EPA approval for a site-specific NO_x limit for certain process heaters in both of these subcategories that are modified or reconstructed. In limited cases, existing natural draft or forced draft process heaters have limited firebox size or other constraints such that they cannot apply the BDT of ultra-low NO_x burners or otherwise meet the applicable limit. This proposed compliance option would require a detailed demonstration that the application of the ultra-low NO_x burner technology is not feasible and would require that the refinery conduct source tests to develop a site-specific emission limit for the process heater. This analysis would be subject to review and approval by EPA and this review would not be delegable to a State or local agency.

We are not proposing to amend the methods for determining initial compliance with the emission limits for any of the subcategories, although we are proposing to provide owners and operators of process heaters in any subcategory that are equipped with combustion modification-based technology (low-NO_x burners or ultra-low NO_x burners) with a rated heating capacity of less than 100 million British thermal units per hour (MMBtu/hr) the option of using continuous emission monitoring systems (CEMS) (in the final rule, these process heaters must use biennial source testing to demonstrate compliance). We are also proposing to require that owners and operators with process heaters in any subcategory that are complying using biennial source testing establish a maximum excess oxygen concentration operating limit, and comply with the O₂ monitoring requirements for ongoing compliance demonstration.

We are also proposing to provide an alternative format for the emission limits in terms of pounds per million British thermal units (lb/MMBtu) that are equivalent to the concentration-based limits. For newly constructed forced draft process heaters, and for newly constructed, modified and reconstructed natural draft process heaters, the proposed alternative emission limit is 0.035 lb/MMBtu on a 365-day rolling average basis (dry at 0 percent excess air). For modified or reconstructed forced draft process heaters, the proposed alternative emission limit is 0.055 lb/MMBtu on a

365-day rolling average basis (dry at 0 percent excess air). We propose that initial compliance with the lb/MMBtu emission limit would be demonstrated by conducting a performance evaluation of the CEMS in accordance with Performance Specification 2 in appendix B to 40 CFR part 60, with Method 7 of 40 CFR part 60, appendix A-4 as the Reference Method, along with fuel flow measurements and fuel gas compositional analysis. We propose that the NO_x emission rate would be calculated using the oxygen-based F factor, dry basis according to Method 19 of 40 CFR part 60, appendix A-7. We propose that ongoing compliance with this NO_x emission limit would be determined using a NO_x CEMS, a continuous fuel gas flow monitor, and at least daily sampling of fuel gas heat content or composition, averaged over each 365-day period.

The third subcategory we propose to create is for co-fired process heaters. Certain refineries, such as island refineries, do not have natural gas available and must supplement their fuel gas (co-fire) with oil to meet their energy demands. We propose to create this subcategory and set an emission limit for co-fired process heaters because technology is presently not able to achieve as low a level of NO_x emissions as units that are fired by gas alone. The NO_x emission limit for these units is proposed to be the weighted average based on a limit of 0.08 lb/MMBtu for the gas portion of the firing and 0.27 lb/MMBtu for the oil portion of the firing.

Because data indicates that some of these co-fired units may not be able to achieve the NO_x limitations even with ultra-low NO_x burner control technology, we are also proposing to allow owners and operators an alternative compliance option to obtain EPA approval for a site-specific NO_x limit for these process heaters. The site-specific limits for co-fired units would be based on the same factors used to determine site-specific limits for other types of process heaters. All of the requirements for monitoring, recordkeeping, and reporting for co-fired heaters are the same as for other process heaters.

C. What are the proposed amendments to the requirements for affected flares in 40 CFR part 60, subpart Ja?

We are proposing to amend several of the requirements for flares as follows. First, we are proposing to remove the 250,000 standard cubic feet per day (scfd) 30-day average flow rate limit in 40 CFR 60.102a(g)(3) and the requirement for a diagram of the flare

connections in the flare management plan required in 40 CFR 60.103a(a)(1).

Second, we are proposing to require a list of refinery process units and fuel gas systems connected to each affected flare in the flare management plan and to assess and minimize flow to affected flares from these process units and fuel gas systems. We are also proposing to allow additional time for owner and operators of modified flares to develop a flare management plan.

Third, we are proposing to amend the modification provision in 40 CFR 60.100a(c) to exclude certain connections that do not result in emission increases from being modifications. We are not proposing any changes to the definition of "flare" in 40 CFR 60.101a.

Fourth, we are proposing to provide additional time for modified flares that need to install additional amine scrubbing and amine stripping columns to meet the 60 ppmv, 365-day hydrogen sulfide (H₂S) concentration limit; however, we are not proposing any changes to the short- or long-term H₂S concentration limits themselves as they apply to flares as contained in 40 CFR 60.102a(g)(1)(ii).

Fifth, we are proposing changes to 40 CFR 60.103a(b) to specify that a root cause analysis for flares would be required for all events causing total sulfur dioxide (SO₂) emissions from that flare to exceed 227 kilograms (kg) (500 lb) in any 24-hour period. In the final rule, root cause analysis was required when the SO₂ emissions exceeded the applicable emission limits by 500 lb/day.

Sixth, we are proposing to add language to the regulation to make it clear that owners and operators must implement corrective actions on the findings of the SO₂ or flow rate root cause analyses and to specify a deadline for performing the analyses. We are also proposing to allow 2 years for a modified flare to begin complying with these requirements if the owner or operator commits to installing a flare gas recovery system.

Seventh, we are proposing changes to the sulfur monitoring requirements in 40 CFR 60.107a(d) (proposed to be redesignated as 40 CFR 60.107a(e)). The final rule required continuous total reduced sulfur monitoring with CEMS. We are proposing two additional monitoring options for measuring SO₂ emissions to determine if a release would trigger a root cause analysis. Both options would specify procedures for determining total sulfur compound concentrations in the fuel gas entering the flare. The two new proposed options include the use of a CEMS to measure

the concentration of total reduced sulfur compounds of H_2S . If H_2S CEMS are used, periodic manual sampling and analysis would be performed to determine a ratio of the concentration of total sulfur compounds to the concentration of H_2S . This value would be used with the H_2S CEMS data to estimate the daily concentrations of total sulfur compounds. We are also proposing that existing flares that are modified and become affected sources have 18 months to install the sulfur monitoring device. Because we are proposing to allow more time for these flares to install monitoring devices, we are also proposing that root cause analysis and corrective action analysis is not required until 18 months after a modified flare becomes an affected source (i.e., until the monitoring device is in place).

Finally, we are proposing changes to the recordkeeping and reporting requirements at 40 CFR 60.108a(c) and (d) when a root cause analysis and corrective action analysis are required and to add recordkeeping requirements for the proposed monitoring option that is based on periodic manual sampling and analysis.

D. What are the proposed amendments to the definitions in 40 CFR part 60, subpart Ja?

In reviewing the final standards, we determined that the definition of "refinery process unit" is vague and not used consistently in other definitions. For example, a "flexicoking unit" is defined as "one or more refinery process units," but "fluid catalytic cracking unit" is defined as "a refinery process unit." We are proposing to clarify that an affected source is one process unit by amending the definitions of "delayed coking unit," "flexicoking unit," and "fluid coking unit" to be "a refinery process unit" rather than "one or more refinery process units." We are also proposing to amend the definition of "delayed coking unit" to clarify that each coking unit includes all of the coke drums and associated fractionators, and we are proposing to amend the definition of "fluid coking unit" to clarify that each fluid coking unit includes the coking reactor and the coking burner. We are proposing to add definitions of "forced draft process heater," "natural draft process heater," and "co-fired process heater" to define our new subcategories for the process heater emission limits.

We are proposing to add a new definition of "flare gas recovery system." The definition of "flare gas recovery system" is needed because we are proposing requirements for systems

with flare gas recovery. We are also proposing to amend the definition of "process upset gas" to mean "any gas generated by a petroleum refinery process unit as a result of start-up, shut-down, upset or malfunction." This will make the definition the same as the definition of "process upset gas" in 40 CFR part 60, subpart J.

Finally, we are proposing to amend the rule to clarify the definitions of "petroleum refinery" and "refinery process unit." Facilities that only produce oil shale or tar sands-derived crude oil for further processing using only solvent extraction and/or distillation to recover diluent that is then sent to a petroleum refinery are not themselves petroleum refineries. This is because they are only producing feed to a petroleum refinery as a product and not refined products. Facilities that produce oil shale or tar sands-derived crude oil and then upgrade these materials and produce refined products would be a petroleum refinery. In addition, because petroleum coke is a refinery product and anode grade coke is not, process units that calcine petroleum coke into anode grade coke are not petroleum refinery process units. We are proposing to amend the definitions of "fuel gas" and "refinery process unit" to clarify that process units that gasify petroleum coke at a petroleum refinery are refinery process units because they are producing refinery fuel gases and possibly other refined intermediates or final products.

IV. Rationale for the Proposed Amendments

A. What is the rationale for the proposed amendments for affected process heaters?

1. Process Heater Emission Limits

The final rule, in 40 CFR 60.102a(g)(2), established NO_x limits for all new, modified, or reconstructed process heaters with a rated heat capacity of greater than 40 MMBtu/hr of 40 ppmv NO_x (dry basis, corrected to 0 percent excess air) on a 24-hour rolling average basis (there were no subcategories). This limit was more stringent than the NO_x limit that was included in the proposed rule. The NO_x limit was based on emissions tests for low- NO_x and ultra-low NO_x burners on various types of process heaters. After promulgation of the final NO_x limit for process heaters, both Industry Petitioners and HOVENSA raised several issues regarding this limit in their petitions for reconsideration. We address these issues below and provide our rationale for the proposed amendments to the NO_x limits for

process heaters that are included in this action. For details on the data analysis supporting the proposed amendments for process heaters, see the memorandum "Evaluation of Nitrogen Oxides Emissions Data for Process Heaters" in Docket ID No. EPA-HQ-OAR-2007-0011.

Since promulgation of the final rule, Industry Petitioners have provided additional CEMS data indicating that, for certain process heaters, the NO_x emission limit in 40 CFR 60.102a(g)(2) is not achievable by the BDT, ultra-low NO_x burners. Industry Petitioners argued that, due to normal process fluctuations, including process turn downs (operating at as low as half of the rated capacity) and variations in the heat content of the fuel gas, the 40 ppmv NO_x emissions limit is not achievable on a 24-hour average basis; thus, a longer averaging time or a higher limit is needed. In addition, we reviewed the data that we used to establish the emissions limits in the final rule and noted that the data were from short-term source tests and, as such, were not generally indicative of the range of operating conditions that might occur over the course of a year. We concluded that all of these data demonstrate that the final NO_x limit is not always achievable on a 24-hour basis.

We also find that this is a reasonable conclusion because during process turn downs, especially those approaching 50 percent of capacity, which can occur routinely, less fuel gas is combusted without an equivalent reduction in the flow of combustion air. Turn downs, therefore, result in less efficient combustion, which tends to increase NO_x concentrations in the heater exhaust. Even though the concentration of NO_x increases during turn downs, the mass of NO_x emitted does not because there is less exhaust gas produced. Turn downs typically occur in hydrotreater or hydrogen units that have varying operational rates. Some process heaters may be in turn down for months (e.g., when a hydrotreater is using a new catalyst). As Industry Petitioners point out, one way to allow for the variations in emissions that are due to process fluctuations, turn downs, and variations in fuel gas composition is to extend the averaging time over which compliance is determined. Based on the above information, we are proposing changes to the NO_x limit to address these issues.

In the final rule, we considered all process heaters in one category. Section 111(b)(2) of the CAA allows us to "distinguish among classes, types, and sizes within categories" of affected sources when establishing performance standards. Based on data received after

promulgation, we are now proposing to treat natural draft process heaters and forced draft process heaters as two separate subcategories.

Our review of the CEMS data received from Industry Petitioners after promulgation of the final rule indicates that nearly all new, modified, or reconstructed natural draft heaters using ultra-low NO_x burners can achieve NO_x concentrations of less than 40 ppmv on a 365-day rolling average basis (dry at 0 percent excess air). We anticipate that the natural draft process heaters not meeting a 40 ppmv emissions limit on a 365-day rolling average basis have a higher hydrogen content and are currently meeting the proposed 0.035 lb/MMBtu limit (see Section IV.A.2 of this preamble). We found in the additional performance data available for ultra-low NO_x burner retrofits provided by Industry Petitioners during reconsideration that the exhaust gas NO_x concentrations from forced draft process heaters exceeded 40 ppmv on an annual average basis. Industry Petitioners suggest that this is because retrofitting the fireboxes of forced draft process heaters often results in excess oxygen levels and higher flame temperatures that would result in higher NO_x emissions. Moreover, forced draft process heaters often include heat exchangers that provide combustion air preheating, which reduces fuel usage by up to 10 percent but increases the amount of NO_x generated. It would be possible to provide less combustion air preheat, which would lower the inlet combustion air temperatures and NO_x concentrations, but that would come with a reduction in the energy savings from the combustion air preheater. To recognize the difference in these types of process heaters and their performance, and to avoid creating disincentives for energy savings, we propose to subcategorize according to these two types of process heaters and establish separate limits for existing forced draft process heaters that are modified or reconstructed. For new, modified, or reconstructed natural draft process heaters, we are proposing a 40 ppmv emissions limit on a 365-day rolling average basis (dry at 0 percent excess air). For forced draft process heaters, we are proposing limits of 40 ppmv for newly constructed process heaters and 60 ppmv for modified or reconstructed process heaters, both on a 365-day rolling average basis (dry at 0 percent excess air). For modified and reconstructed forced draft process heaters, we believe that the 60 ppmv limit constitutes BDT both because of the achievability of the standard and

because of the energy penalty noted above that may occur were the units required to meet the 40 ppmv limit.

The annual average format provides one means of dealing with process and control system variability. We also considered shorter averaging times, but these would require higher concentration limits and special provisions to deal with turn down situations. California's South Coast Air Quality Management District (SCAQMD) Rule 1109 effectively establishes a mass NO_x emissions rate limit for the process heater when operated at maximum capacity and allows the owner or operator of the process heater to meet this mass emissions rate when the unit is not operating at maximum capacity. We request comment on the advantages and disadvantages of providing an extended averaging time versus providing specific provisions to account for higher NO_x concentrations observed during process heater turn downs where the process heater is running at about 50 percent or less of capacity.

We also received information from Industry Petitioners that a particular type of forced draft process heater, one that is also equipped with a combustion air preheater, may not consistently meet the proposed emissions limit for newly constructed forced draft process heaters of 40 ppmv (0.035 lb/MMBtu). We do not want to discourage this type of system because of the potential fuel savings, but we do not have data supporting Industry Petitioners' assertion. We are, therefore, requesting comment and supporting data on the need to establish a subcategory for this type of new forced draft process heater, and to establish a higher NO_x limit for this particular type of new forced draft process heater.

2. Alternative lb/MMBtu Format

Industry Petitioners suggested that we provide an alternative lb/MMBtu emission limit format to address potential issues related to the combustion of high-hydrogen fuel gases. In evaluating this request, we looked at the differences in combusting high-hydrogen fuel gases versus more typical low hydrogen, hydrocarbon-based fuel gases.

Combustion of a wide range of fuel gases in a given process heater produces approximately the same quantity of NO_x. Fuel gases contain varying amounts of hydrogen, and in certain cases, such as hydrotreaters, hydrogen is a significant portion of the fuel gas. Combustion of hydrocarbon fuel gases, such as methane, produce carbon dioxide, which adds to the volume of

the gas stream. Combustion of hydrogen fuel gases produces water vapor, which also increases the gas stream on an actual basis. Since our emission limit is on a dry basis, however, this water vapor is discounted and the exhaust gases from combustion of high-hydrogen fuel gases are more concentrated than they are with low-hydrogen fuel gases. This means that if there is only a concentration-based emission limit, high-hydrogen fuel gases would be subject to more stringent emission limits than more typical hydrocarbon fuel gases.

For a range of hydrogen contents in the fuel gas, the 0.035 lb/MMBtu NO_x emissions limit in the final rule would convert to a range of NO_x concentrations on a dry basis of from 32 to 50 ppmv. This means our emission limit of 40 ppmv, which is the midpoint of this range of hydrogen concentrations, equates to a 0.035 lb/MMBtu limit. This value was suggested by Industry Petitioners and is also used in other rules and recent consent decrees between many petroleum refiners and the United States government (representing EPA and various individual States, depending on the petroleum refining company). The consent decrees are in effect on over 90% of domestic refining capacity. These negotiated requirements often set controls in place that have provided the basis (including performance test data and ongoing monitoring data) for our BDT performance levels for process heaters. Similarly, the 0.055 lb/MMBtu NO_x emission limit reasonably equates to a 60 ppmv NO_x concentration limit. We request comments on the use of these lb/MMBtu limits and if these values are reasonably equivalent to the corresponding concentration limits.

3. Co-Fired Process Heaters

In their petition, HOVENSA raised the issue of NO_x limits for co-fired units. Certain refineries, such as island refineries, do not have natural gas available and must supplement their fuel gas with oil to meet their energy demands. In addition, in times of limited natural gas supplies, industry can undergo gas curtailments. While refiners may have separate burners for oil in this situation, they may also be set up to co-fire oil. Technology for these co-fired systems are presently not able to achieve as low a level of NO_x emissions as systems that are fired by gas alone. We received vendor-guaranteed performance levels for several ultra-low NO_x burner suppliers for co-fired units. These data indicate a range of NO_x emissions from 0.080 to

0.19 lb/MMBtu for gas firing and 0.27 to 0.63 lb/MMBtu for oil firing.

After considering all these data, we are proposing the lowest available NO_x performance limit of the different ultra-low NO_x burner designs as the emissions limit for co-fired process heaters. When fired with gas, we are proposing that these burners achieve a NO_x limit of 0.08 lb/MMBtu and when fired with oil, a NO_x limit of 0.27 lb/MMBtu. When the unit is co-fired, we are proposing a weighted average emissions limit for these units based on a limit of 0.08 lb/MMBtu for the gas portion of the firing and 0.27 lb/MMBtu for the oil portion of the firing.

In addition, we are also proposing an alternative performance standard of 150 ppmv for these units when they are being co-fired. This value represents the performance of these process heaters using a mid-range mixture of gas and oil as fuel. We are proposing this concentration-based alternative standard because it provides a simple direct means of measuring compliance (no need to measure oil and gas fuel flows or BTU contents of the fuels).

We request comment on the unique issues related to process heaters on island refineries and situations such as natural gas curtailments that would lead non-island refineries to have burners that are designed to co-fire both oil and fuel gas. We also request comments on limitations that would keep these refiners from installing the best-performing burners and, for process heater/burner combinations that are available that limit NO_x emissions, what NO_x limits would be achievable. Finally, we request comments on the alternative concentration limit and on other methods that may be available to determine compliance with the co-fired process heater NO_x limits.

4. Site-Specific Emission Limits

We are also proposing an alternative compliance option for owners and operators to obtain EPA approval for a site-specific NO_x limit for: (1) Modified or reconstructed natural draft and forced draft process heaters that have limited firebox size or other limitations and therefore cannot apply the BDT of ultra-low NO_x burners and (2) co-fired process heaters. This approach has been used in the past to determine performance levels for boilers (see 40 CFR 60.44b(f)) and would allow for limits that are tailored to the specific process heater.

Certain natural draft and forced draft process heaters, generally ones that are more than 30 years old, have smaller fireboxes than more recent heaters. For these heaters, it is physically impossible

to install ultra-low NO_x burners because these burners minimize NO_x emissions through the use of long flame fronts. For these or other process heaters that cannot install ultra-low NO_x burners, owners or operators can elect to submit to the Administrator for approval a site-specific NO_x emission limit. This request must include: (1) The reasons why ultra-low NO_x burners or other means cannot be used to meet the emission limits; (2) test data that reflects performance of technologies that will otherwise minimize NO_x emissions; and (3) the means by which they will document continuous compliance.

We request comments on possible ways of retrofitting ultra-low NO_x burners in space-limited situations, such as raising the firebox height to accommodate flame length, which would enable modified or reconstructed natural draft and forced draft process heaters to install this control technology in space-limited situations.

In addition, because of the high level of uncertainty and site-specific nature of the specification of NO_x limits for co-fired process heaters, we are also proposing an alternative compliance option for owners and operators of co-fired process heaters to obtain EPA approval for a site-specific NO_x limit. The request to the Administrator must follow the same requirements as described above for natural draft and forced draft process heaters.

Finally, we request comments on all aspects of the use of site-specific testing to establish EPA-approved limits for size-limited natural draft and forced draft process heaters and for co-fired process heaters.

B. What is the rationale for the proposed amendments for affected flares?

1. Soliciting Comment on the Flare Requirements in the Final Rule

All of the Petitioners noted that many of the flare provisions in the final rule were not in the May 14, 2007, proposal (72 FR 27178) and that there was no opportunity for notice and comment. Therefore, we now solicit comments on all aspects of the final rule flare provisions on which the public has not previously had an opportunity to comment and that we do not propose to change in this action. In addition, the following sections describe and give our rationale for proposed changes to these final provisions.

We also note that we have prepared revised cost and emissions reduction impact estimates for the flare requirements that we are proposing in this notice. Based on information provided by Industry and

Environmental Petitioners, we now believe that there will be more existing flares that will become affected facilities in the first 5 years of this rule and that there are more sulfur emissions from events that would cause root cause analysis than we anticipated. This leads both the costs and the emission reductions anticipated in the final rule to increase. The proposed amendments would remove some requirements in the final rule while strengthening others. Overall, we believe that the revised impacts represent the rule as it would be amended by today's action. The revised impacts for proposed amendments to the flare requirements are presented in Section V of this preamble; for details on the revised impacts estimates for flares, see Docket ID No. EPA-HQ-OAR-2007-0011.

The following sections outline the major areas for which Petitioners have sought reconsideration. They provide overview of the Petitioners' concerns and propose our response.

2. Definition of "Flare"

Industry Petitioners and HOVENSA both requested that we change the definition of flare so that it includes only the seal pot and flare itself and not the flare header and associated equipment that provides the flare gas from the process units or fuel gas system to the flare burner assembly. Industry Petitioners suggested that we revise the definition of the flare and thus the flare affected source in order to limit applicability of the flare provisions. By limiting the definition of flare to only the downstream components, they suggested that any connection made upstream of the seal pots would not be considered a modification. We disagree with this outcome because we are not trying to limit the affected facility and what would be a modification. Including the flare header system is crucial to our approach in that the connections that trigger a modification are almost always made prior to the seal pot. Accordingly, adopting a narrower definition may result in many of the activities that increase emissions at the flare being excluded from review. We are, therefore, retaining the definition of flare as promulgated in the final rule and includes the upstream components of the flare header as well as the actual flare itself. We are requesting comments on all aspects of the flare definition, including Industry Petitioners' suggested revisions to the definition.

A related concern Industry Petitioners raised regarding the flare definition we have included in 40 CFR part 60, subpart Ja is the impact of cross-referencing it in 40 CFR part 60, subpart

J. Specifically, Industry Petitioners assert that we expanded the applicability of subpart J and created retroactive noncompliance issues for certain existing flares when we cross-referenced the flare definition in 40 CFR 60.100(b). Industry Petitioners, however, misinterpret the intent and impact of this cross-reference. The intent of the provision was not to expand the definition of fuel gas combustion device under subpart J; rather, it was included only to clarify that flares were not subject to the new flare requirements in subpart Ja until after the date of publication of the final rule.

In the final rule we stated that a “fuel gas combustion device under paragraph (a) of this section,” that is also a “flare as defined in § 60.101a,” is still subject to the requirements in 40 CFR part 60, subpart J, not 40 CFR part 60, subpart Ja, if it “commences construction, reconstruction, or modification after June 11, 1973, and on or before June 24, 2008.” In other words, the provision only changes the applicability date for flares that have always fallen within the definition of fuel gas combustion device in subpart J, i.e., it does not impact applicability.

We recognize that there may be disagreement regarding coverage of flares. Specifically, we recognize that there may be disagreement under 40 CFR part 60, subpart J regarding what parts of a flare are covered as fuel gas combustion devices. That disagreement is, however, not being addressed by this rulemaking, nor was it addressed in the rulemaking published on June 24, 2008. Rather, such disagreements should be addressed through other available CAA regulatory mechanisms, such as through Applicability Determinations under 40 CFR 60.5.

3. Flare Modification Provision

Each petition we received requested that we reconsider the modification provision in 40 CFR 60.100a(c) which states that “a modification to a flare occurs if: (1) Any new piping from a refinery process unit or fuel gas system is physically connected to the flare (e.g., for direct emergency relief or some form of continuous or intermittent venting); or (2) a flare is physically altered to increase flow capacity of the flare.”

In developing this provision, we anticipated that all new connections to the flare would result in an increase in emissions from the flare, and thus qualify as a modification to the flare under the statutory definition. While we have historically identified emission increasing activities based on a numerical calculation, see 40 CFR

60.14(a) and (b), we believe that given the intermittent nature of flare use, the variable composition of gas being flared, and other factors, the listing approach we are proposing to adopt here will help ease implementation issues while identifying “any physical change in, or change in the method of operation of [an affected facility] which increases the amount of any air pollutant emitted.” CAA section 111(a)(4). Thus, new connections of refinery process units to the flare would trigger 40 CFR part 60, subpart Ja applicability for the flare.

Industry Petitioners subsequently submitted data asserting that many new connections made to the flare do not result in an increase in emissions from the flare and, in fact, may decrease the emissions from the flare. For example, they asserted that installing a flare gas recovery system requires making several new connections to the flare, but these connections do not increase the emissions from the flare, so they should not qualify as a modification under CAA section 111(a)(4) and should not trigger 40 CFR part 60, subpart Ja applicability for the flare.

We have evaluated a number of potential flare connection scenarios and identified the types of connections that do not result in an increase in emissions from the flare. Based on our evaluation, we are proposing amendments to the modification provision in 40 CFR 60.100a(c) that would clarify what constitutes a modification of the flare and would exclude these types of connections because they will not result in an emissions increase as required by the definition of modification. See CAA section 111(a)(4) (“modification means any physical change in, or change in the method of operation of, a stationary source which increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted.”). Specifically, we are proposing to exclude the following types of connections: (1) Those associated with the installation of a flare gas recovery system; (2) connections required to install a monitoring device on the flare (e.g., flow meter, sulfur monitor, or pressure transducer); and (3) connections used to replace or upgrade old piping or pressure relief systems that are already connected to that flare. We also request comment, including supporting documentation, on whether there are other types of connections that do not result in an increase in emissions from a flare.

Industry Petitioners have also suggested that some *de minimis* emissions increases should be allowed without triggering NSPS subpart Ja

applicability. Such exceptions are permissible but not required under the modification provisions of CAA section 111—see *Alabama Power vs. Costle*, 636 F.2d 323, 360–61 (D.C. Cir. 1980). We request comments on a *de minimis* approach and on specific changes that may occur to flares that will result in *de minimis* increases in emissions. We also request comments on the type, number, and amount of emissions that would be considered *de minimis*.

Finally, Industry Petitioners requested that we consider the merits of a two-tiered system for existing facilities to become affected facilities through modifications. They suggest that the existing definition of modification may be appropriate for triggering the flare gas minimization requirements under 40 CFR 60.103a work practice standards, but that we should consider a separate, more substantive, trigger for requirements for fuel gas combustion devices under 40 CFR 60.103a(g)(1). We do not see the need for this type of system, especially considering all the proposed changes included in this notice. For example, we are proposing several changes to the flare provisions that would reduce the number of changes that would make an existing source an affected facility and reduce the scope of the requirements, including, but not limited to, excluding some connections from the definition of modification, including startup and shutdown fuel gases as process upset gases which are exempt from the fuel gas standards, providing additional time to comply when new fuel gas sulfur removal equipment is needed, and removing the flow limits. Moreover, we are concerned that their approach would not be consistent with the broad statutory definition of modification and the requirement that new sources, including modified sources, comply with the NSPS. We see no basis in these statutory provisions to provide that different types of modifications trigger fundamentally different NSPS requirements. We are nonetheless requesting comments on this approach and the statutory basis for this adoption.

4. Application of Fuel Gas Combustion Device Sulfur Limits to Flares

a. “Process upset gas” definition. We are proposing to include flaring events from startups and shutdowns in the definition of “process upset gas.” The final 40 CFR part 60, subpart Ja definition excludes startups and shutdowns from the definition of process upset gases. Process upset gases are exempt under 40 CFR 60.103a(h) from meeting the sulfur standards (H₂S or SO₂) for fuel gas combustion devices

in 40 CFR 60.103a(g)(1). Our basis for excluding these events in the final rule was that, in conjunction with our flow limit, BDT was the capture and treatment of these gases. Certain refiners were able to nearly or completely eliminate flaring, including startup and shutdown events that normally released gases to the flare. Since promulgation of the final rule, we have learned from Industry Petitioners that many refiners must release gases to their flares during startup and shutdown events. During startup and shutdown of a process unit, refiners will purge the process unit with nitrogen gas to ensure that hydrocarbons are completely removed from the system. In most cases, the gas is flared because it is a large quantity of gas over a short period of time, and the high concentration of nitrogen will disrupt the combustion and NO_x control in the refinery process heaters and boilers. These gases cannot typically meet the SO₂ or H₂S standards for fuel gas combustion devices. The BDT analysis is based on removing H₂S from continuous or regular intermittent streams and does not include controlling sulfur in potentially large, infrequent fuel gas flows that we now understand are necessary in some cases. We believe that SO₂ emissions from these events can be minimized or prevented by addressing them with a flare management plan.

b. *Long-term H₂S concentration limit.* Industry Petitioners also expressed concern that meeting the H₂S limit of 60 ppmv on a 365-day rolling average basis (long-term sulfur limit) will be difficult for affected flares because of the cost of treatment and the method of complying with the long-term average. These Petitioners have indicated that for typically intermittent flaring events, compliance with an annual average limit is difficult because sulfur content may be variable and less likely to be normalized over a limited number of data points. We believe that we have adequately addressed the issue by proposing to exclude process upset gases, which would include gases from startups and shutdowns from this long-term sulfur limit, and we are not proposing any changes to this long-term limit.

Industry Petitioners suggest that the flare management plan and root cause analysis would be an effective means of limiting SO₂ emissions from flares without the long-term limit. We are not proposing changes to the long-term limit itself, but we are requesting comment on whether the rule should require the long-term sulfur limit for all flares or whether, to address the Industry Petitioners' concern, it should limit

applicability of the long-term sulfur limit only to flares that operate a minimum number of hours per year.

We are proposing to provide additional time for modified flares to meet the sulfur limits in cases where the treatment system does not already have sufficient amine treatment capacity to remove the H₂S. Many of the connections that would trigger applicability to 40 CFR part 60, subpart Ja are critical to the safe and efficient operation of the refinery. These connections can and often must be installed quickly, in much less time than it takes to install sulfur removal equipment. For these reasons, we are proposing that refineries that must install additional sulfur removal equipment have 2 years after startup of the modified flare to install the sulfur removal and recovery equipment to comply with the standards.

We expect this additional time will only be necessary in limited circumstances due to the consent decrees and refinery operating practices and we expect most of the existing flares would already have sufficient sulfur removal equipment to treat additional fuel gas streams. However, for those that do not, it is necessary for these systems to have additional time. Due to the planning, design, purchasing, and installation required to expand fuel gas treatment systems, we are proposing to provide 2 years after startup of a modified flare to comply with the long-term sulfur limit for those facilities that certify that they need to install additional sulfur removal equipment, such as amine towers or sulfur recovery plants.

We request comments on phasing out this time allowance for the installation of fuel gas treatment systems. We note that a substantial portion of the petroleum refineries in the United States are under consent decrees with fuel gas sulfur requirements similar to the requirements of subpart Ja as proposed to be amended. In this action, we are proposing to clarify what constitutes modification of a flare, and refiners are now aware that modification of the flare may happen quickly and that they will be subject to the long-term sulfur limits. Therefore, we expect that refiners would (or are required to under the consent decrees) be able to install sufficient sulfur removal equipment over the next several years to comply with the long-term sulfur limit upon modification. We request comment on whether 5 years is sufficient time for all flares potentially subject to subpart Ja to have sulfur removal equipment in place and, therefore, not need this added time for installation of equipment.

5. Flare Flow Rate Limit

Both Environmental and Industry Petitioners questioned the 250,000 scfd flow rate limit for flares. Environmental Petitioners supported the provisions in the May 14, 2007, proposed rule eliminating routine flaring from affected fuel gas producing units (72 FR 27178), and they were concerned that EPA issued standards would allow any routine amount of flaring. Industry Petitioners, on the other hand, suggested that specific flow limits are not warranted.

In response to these petitions, we have reconsidered the final rule. First, we considered reinstating the requirement for no routine flaring as requested by Environmental Petitioners. This action would have also required returning to the concept of applicability of the no routine flaring requirement to fuel gas producing units. Under the 2007 proposed rule, only the gas stream from the modified fuel gas producing unit was barred from routine flaring. Under the final rule, all of the units connected to the flare were addressed. We concluded that this was a preferable approach because it allowed us to consider how the flare should be managed for all gases flared. We also concluded that no routine flaring was not feasible in many cases where gases routed to flares could not be effectively captured, stored, and returned to the process or recovered as fuel.

We then considered the flow limit of 250,000 scfd in the final rule. In developing the final rule, we believed that sweep gas flow needed to maintain the readiness of the flare would be only about 20 percent of the final flow limit. Based on the industry design data, it appears likely that there are some flares that require significantly higher sweep gas rates than we originally considered, and some sweep gas rates may be as high as the 250,000 flow limit itself. For these cases, the flow rate limit would be unachievable. Moreover, we considered the effect that having a flow limit might create a perverse incentive to increase the number of flares at a facility to spread the flow out and avoid triggering the flow limit for individual flares. Industry Petitioners suggested that there is a wide variety of configurations and situations and a one-size-fits-all solution of a flare flow limit is not appropriate. They believe that the flare management plan will provide site-specific flexibility to minimize flaring. We are proposing to strengthen both the flare management plan and the root cause analysis provisions, and with those changes, we believe that the 250,000 scfd flow limit is not necessary. Therefore, we are

proposing to remove the 250,000 scfd flow rate limit in the final rule. We request comments on the sufficiency of the proposed flare management plan to address continuous flows to flares, suggestions for other approaches to limit the volume of gas flared, and an alternative higher flow rate limit that could be appropriate.

6. Total Reduced Sulfur and Flow Monitoring Requirements for Flares

We are not proposing to remove the requirements to monitor the flare flow and sulfur content from the final 40 CFR part 60, subpart Ja standards. We continue to believe that monitoring is the key to understanding and minimizing emissions from these diverse and highly variable flare gas systems. We are proposing clarifications and additional options for measuring the sulfur content of flare gases. We are proposing to allow monitoring of H₂S or total sulfur at the flare as additional options for quantifying SO₂ emissions. In the case of H₂S monitoring for flares, we are proposing that owners and operators must supplement the measured readings with additional data to capture non-H₂S sulfur compounds that produce SO₂ emissions. For flare flow monitoring, we are requesting comments on exemptions from flow monitoring for certain cases where monitoring may be unnecessary. We are proposing to add requirements to keep records of the CEMS data, the sampling and analysis data that provide the underlying concentration information needed to calculate the daily SO₂ emissions, and the daily flare flow rate. Finally, we are proposing to allow the owner or operator of an existing flare that becomes a modified source 18 months from the date the flare becomes a modified source to install sulfur and flow monitoring devices. The final rule allowed 1 year, but Industry Petitioners indicated that since more flares are expected to become modified sources than we originally anticipated, additional time should be allowed to ensure that vendors have sufficient time to provide monitoring devices to all modified sources.

Industry Petitioners suggested that we exempt certain flares from the requirement to install continuous flow monitors. Examples they cited include flares that have flare gas recovery systems or other flares that do not routinely have any flow, such as emergency release-only flares, flares on pressure storage vessels, and flares that receive flow only during periods of startup or shutdown. We are not aware of any alternative approaches for such flares that would be effective at

determining the need for a root cause analysis and are not proposing such a requirement. Moreover, the costs for flow monitors are reasonable and they provide a direct measure of emissions from the flare. We request comments on the need to provide exemptions from flow monitoring. Commenters should provide specific cases where they believe that monitoring is not necessary and how compliance with the root cause analysis and corrective action provisions would be maintained.

Installation of flare gas recovery systems requires significant planning, design, installation, and testing time, whereas some of the connections that trigger applicability, as discussed previously, can and must be accomplished very quickly. We believe it is important to not create disincentives to the addition of flare gas recovery systems. Therefore, for a modified flare that is being retrofitted with a flare gas recovery system, we are proposing to provide 2 years from the date that the flare becomes an affected facility to comply with the flare management plan, the sulfur and flow monitoring requirements, and the SO₂ and flow root cause analysis and corrective action analysis requirements.

7. Other Proposed Amendments and Requests for Comments

a. *Root cause analysis.* We are proposing to clarify and revise the requirements of 40 CFR 60.103a(b) for root cause analysis. For all sulfur recovery plants and all fuel gas combustion devices except flares, we are clarifying that a root cause analysis is required when SO₂ emissions exceed the applicable emissions limit by at least 500 lb in any 24-hour period. The final rule included the same requirement. We are proposing to amend the rule so that root cause analysis is required for flares for any 24-hour period in which 500 lb or more of total SO₂ is emitted (not SO₂ beyond the applicable emissions limit and not limited to a single event). We are proposing this amendment because flares receive numerous streams that tend to be variable in both composition and flow and are discharged intermittently so that the flow into a flare header at any given time may not be easily associated with one single event or even one single process unit operation. Therefore, we are basing the requirement on a mass per unit time basis rather than on an event by event basis. Further, since we are proposing to eliminate the flow rate limit, there is no applicable mass limit beyond which an exceedance would be calculated.

We are also proposing to require a corrective action analysis and corrective actions for both an SO₂ and flow rate root cause analysis (at 40 CFR 60.103a(b) and (a)(5), respectively). We believe that an important part of conducting a root cause analysis is ensuring that the root cause of the release is addressed and that a reasonable attempt is made at preventing a similar occurrence from causing a future release.

We are proposing to clarify that an owner or operator should begin the root cause analysis and corrective action analysis as soon as possible after a discharge. No later than 45 days after the discharge, the owner or operator must record detailed information about the discharge, including the results of the root cause analysis and corrective action analysis, and either implement corrective action, develop an implementation schedule for corrective action that cannot be completed in the 45 days following the discharge, or explain the basis for the conclusion that corrective action should not be conducted.

Finally, we are proposing to clarify that root cause analysis and corrective action analysis are not required for a modified flare until the compliance date for installation of the sulfur and flow monitoring devices. As described earlier in this preamble, we propose to allow a modified flare 18 months to install monitoring devices or 2 years if the owner or operator commits to installing a flare gas recovery system.

We are not changing the final rule inclusion of startup or shutdown events from the root cause analysis requirements for SO₂. In cases where exceedances are related to a startup or shutdown, the root cause analysis would identify these events as causes, and the corrective action analysis would address potential mitigation options.

b. *Flare management plan.* We are proposing two amendments to the flare management plan requirements other than the flow rate root cause analysis and corrective action analysis. First, we are proposing to extend the time provided to develop the flare management plan for modified flares. The final rule provided 1 year, which was the same amount of time provided for installation of sulfur and flow monitors. Because the flare management plan includes a requirement to describe methods for monitoring flow rate to the flare, we are proposing that the owner or operator of a modified flare must develop and implement the flare management plan on the same timeline as the installation of the flow monitor. Specifically, the owner or operator of a

modified flare must develop and implement the flare management plan no later than 18 months after the flare becomes an affected facility, unless the owner or operator of the affected flare commits in writing to install a flare gas recovery system, in which case the owner or operator of a modified flare must develop and implement the flare management plan no later than 2 years after the flare becomes an affected flare.

Second, Industry Petitioners noted that a diagram illustrating all connections to the flare would be very complicated and difficult to keep current. Therefore, we are proposing to require a list of refinery process units and fuel gas systems connected to each affected flare in the flare management plan and an assessment of whether discharges to affected flares from these process units and fuel gas systems can be minimized. This requirement is consistent with the intent in the final rule to track which refinery process units and fuel gas systems are connected to each flare and when a new connection is made, but it should be less burdensome than the requirement in the final rule.

c. Compliance with State or local rules as deemed compliance with subpart Ja. We note that there are several State and local air pollution control authorities that have requirements in place to address flare gas flow and SO₂ emissions from refinery flares. For example, SCAQMD has standards for flares (Rule 1118) that include many requirements that are similar to the flare standards as amended by this action in 40 CFR part 60, subpart Ja. Industry Petitioners requested that we recognize this potential for overlap with these existing provisions and that we consider allowing flares subject to both this rule and SCAQMD Rule 1118 to use compliance with Rule 1118 as compliance with the flaring provisions in subpart Ja. We request comment on

the equivalency of the subpart Ja requirements as proposed to be amended today and the SCAQMD Rule 1118. We also request comment on whether EPA could deem a facility in compliance with subpart Ja as proposed to be amended today if that facility was found to be in compliance with SCAQMD Rule 1118, or other equivalent State or local rules.

d. New source trigger date for flares. In the final rule, we provided that the subpart Ja requirements for flares would apply only to flares commencing construction, reconstruction, or modification after June 24, 2008, the date of the final rule. We recognized that this was a departure from the normal course, where an affected facility must comply with the final standard if it commences construction, reconstruction or modification after the proposal date, but justified this departure because “we are promulgating a newly defined affected facility, adding a new provision specifically defining what constitutes a modification of a flare, adding several new requirements, and adding a definition of a flare. All of these changes significantly alter what would be an affected facility and the obligations of the affected facility for purposes of reducing flaring.” 73 FR at 35856. We believe this decision is justified under the definition of “new source,” CAA section 111(a)(2), because the changes meant that numerous flares that were modified according to the final rule were not covered by the proposed rule and thus the proposal was not a standard “which will be applicable to such source[s].” Reconsideration has not been sought on this decision and we are not reopening that final action for comment.

In connection with their reconsideration petition, Industry Petitioners have requested that the “new source” trigger date for flares be changed to the date of this reconsideration proposal, December 22,

2008. We are concerned that such a change would be improper under the definition of “new source” at CAA section 111(a)(2). That provision provides that “[t]he term ‘new source’ means any stationary source, the construction * * * of which is commenced after the publication of regulations (or, if earlier, proposed regulation) prescribing a standard of performance under this section which will be applicable to such source.” As noted above, 40 CFR part 60, subpart Ja’s applicability provisions for flares are currently June 24, 2008 (the date of “publication of regulations * * * prescribing a standard of performance”). While a reconsideration proceeding under CAA section 307(d) constitutes a new rulemaking and acts to cure a procedural flaw in the final rule, we do not interpret it as invalidating or rendering a nullity to the prior rulemaking. This position is supported by the structure of CAA section 307, which provides that the rule remains in effect pending the reconsideration, subject to the authority of the Administrator to stay the effective date. See CAA section 307(d)(7)(B) (“Such reconsideration shall not postpone the effectiveness of the rule.”). We also believe this position to be consistent with Congressional intent, as reflected in the definition of “new source,” which is tied to the date of proposal, that sources be subject to the final rule if they are on notice that the final rule may apply to them. Nonetheless, we solicit comment on Industry Petitioners’ request and, in particular, whether it could be accommodated consistent with the text of CAA section 111(a)(2).

C. What miscellaneous corrections are being proposed?

See Table 1 of this preamble for the miscellaneous technical corrections not previously described in this preamble that we are proposing throughout 40 CFR part 60, subpart Ja.

TABLE 1—PROPOSED TECHNICAL CORRECTIONS TO 40 CFR PART 60, SUBPART J

Section	Proposed technical correction and reason
60.101a	In the definition of “Sulfur recovery plant,” replace “HS ₂ ” with “H ₂ S” to correct a typographical error.
60.102a(f)(1)(ii)	Replace “10 ppm by volume of hydrogen sulfide (HS ₂)” with “10 ppmv of H ₂ S” to correct a typographical error.
60.105a(b)	Replace “paragraphs (b)(1) through (3) of this section” with “paragraphs (b)(1) and (2) of this section” to remove the reference to a nonexistent paragraph.
60.105a(i)(5)	Replace “Except as provided in paragraph (i)(7) of this section, all rolling 7-day periods” with “All rolling 7-day periods” to remove the reference to a nonexistent paragraph.
60.107a(2)(i)	Replace “320 ppmv H ₂ S” with “300 ppmv H ₂ S” to make the span value for an H ₂ S monitor consistent with the span value in subpart J.
60.108a(b)	Replace “the information described in paragraph (e)(6) of this section” with “the information described in paragraph (c)(6) of this section” to correct the reference to a nonexistent paragraph.

V. Summary of Cost, Environmental, Energy, and Economic Impacts

The cost, environmental, and economic impacts presented in this section for flares are revised estimates for the impacts of the final requirements of 40 CFR part 60, subpart Ja as proposed to be amended by this action. The impacts are presented for petroleum refinery flares that commence construction, reconstruction, or modification over the next 5 years. Industry Petitioners noted that we underestimated the number of affected flares in our analysis of the final rule.

Based on the clarification of a flare modification, we agree, and we anticipate that there will be 150 affected flares over the next 5 years, or about one flare per refinery, and 80 percent of those will be modified or reconstructed. Environmental Petitioners provided upset data from the Texas Commission on Environmental Quality showing that flares can release much higher quantities of SO₂ emissions than we estimated in our analysis of the final rule, and they stated that our low estimates resulted in underestimated SO₂ emissions reductions for root cause

analyses. Based on the data provided, our updated analysis includes three model flare releases with different amounts of SO₂ emissions that are prevented by root cause analysis. The values in Table 2 of this preamble include the costs for those 150 flares to comply with the H₂S emissions limits for fuel gas combustion devices, the flare management plan, sulfur and flow monitoring requirements, and root cause analyses.

For details on the updated impacts estimates for flares, see Docket ID No. EPA-HQ-OAR-2007-0011.

TABLE 2—NATIONAL FIFTH YEAR IMPACTS OF PROPOSED EMISSIONS LIMITS AND WORK PRACTICES FOR FLARING DEVICES SUBJECT TO 40 CFR PART 60, SUBPART J

Requirements	Capital cost (\$1,000)	Total annual cost without natural gas offset (\$1,000)	Natural gas offset (\$1,000)	Total annual cost (\$1,000/yr)	Emission reduction (tons SO ₂ /yr)	Emission reduction (tons NO _x /yr)	Emission reduction (tons VOC/yr)	Overall cost-effectiveness (\$/ton)
New Flares	46,000	13,000	(12,000)	410	5,900	4	240	67
Modified and Reconstructed Flares	300,000	81,000	(49,000)	32,000	24,000	17	960	1,300
Total	350,000	94,000	(62,000)	32,000	30,000	21	1,200	1,000

The cost, environmental, and economic impacts for the proposed amendments to 40 CFR part 60, subpart Ja for process heaters are not expected to be significantly different than those reported for the final rule. We expect owners and operators to install the same technology to meet these proposed amendments that we anticipated they would install to meet the final subpart Ja requirements (i.e., ultra-low NO_x burners). Our proposal to create new subcategories of process heaters and set different emissions limits for those subcategories does not impact the control or compliance methods.

VI. Statutory and Executive Order Reviews

A. Executive Order 12866: Regulatory Planning and Review

Under Executive Order 12866 (58 FR 51735, October 4, 1993), this action is a “significant regulatory action” because it may raise novel legal or policy issues. Accordingly, EPA submitted this action to the Office of Management and Budget (OMB) for review under Executive Order 12866, and any changes made in response to OMB recommendations have been documented in the docket for this action.

B. Paperwork Reduction Act

This action does not impose any new information collection burden. The information requirements in these

proposed amendments would add new compliance options, provide more time to comply with the requirements for fuel gas monitoring systems, and clarify the definition of a “flare modification.” These proposed changes will not result in any increase in burden and are expected to reduce the costs associated with testing, monitoring, recording, and reporting. However, the information collection requirements contained in the existing regulation (40 CFR part 60, subpart Ja) under the provisions of the Paperwork Reduction Act, 44 U.S.C. 3501, et seq., have been sent to OMB for approval under EPA ICR number 2263.02. The OMB control numbers for EPA’s regulations in 40 CFR are listed in 40 CFR part 9.

C. Regulatory Flexibility Act

The Regulatory Flexibility Act generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure Act or any other statute unless the agency certifies that the rule would not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small not-for-profit enterprises, and small governmental jurisdictions.

For purposes of assessing the impact of today’s proposed action on small entities, small entity is defined as: (1) A small business whose parent company

has no more than 1,500 employees, that is primarily engaged in refining crude petroleum into refined petroleum as defined by NAICS code 32411 (as defined by Small Business Administration size standards); (2) a small governmental jurisdiction that is a government of a city, county, town, school district, or special district with a population of less than 50,000; and (3) a small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field.

After considering the economic impacts of this proposed rule on small entities, I certify that this action will not have a significant economic impact on a substantial number of small entities. Our analyses indicate that the proposed amendments will not increase the costs associated with the final rule and may decrease costs. Therefore, no adverse economic impacts are expected for any small or large entity. We continue to be interested in the potential impacts of the proposed rule on small entities and welcome comments on issues related to such impacts.

D. Unfunded Mandates Reform Act

This rule contains no Federal mandates under the provisions of Title II of the Unfunded Mandates Reform Act of 1995 (UMRA), 2 U.S.C. 1531–1538 for State, local, or tribal governments or the private sector. It does not contain a Federal mandate that

may result in expenditures of \$100 million or more for State, local, and tribal governments, in the aggregate, or to the private sector in any one year. The costs of the proposed amendments would not increase costs associated with the final rule. Therefore, this rule is not subject to the requirements of sections 202 and 205 of the UMRA.

This rule is also not subject to the requirements of section 203 of UMRA because it contains no regulatory requirements that might significantly or uniquely affect small governments. The proposed amendments contain no requirements that apply to such governments, and impose no obligations upon them.

E. Executive Order 13132: Federalism

Executive Order 13132, entitled *Federalism* (64 FR 43255, August 10, 1999), requires EPA to develop an accountable process to ensure “meaningful and timely input by State and local officials in the development of regulatory policies that have federalism implications.” “Policies that have federalism implications” is defined in the Executive Order to include regulations that have “substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government.”

This proposed rule does not have federalism implications. It will not have substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government, as specified in Executive Order 13132. They do not modify existing responsibilities or create new responsibilities among EPA regional offices, States, or local enforcement agencies. Thus, Executive Order 13132 does not apply to this rule.

In the spirit of Executive Order 13132, and consistent with EPA policy to promote communications between EPA and State and local governments, EPA specifically solicits comment on this proposed rule from State and local officials.

F. Executive Order 13175: Consultation and Coordination with Indian Tribal Governments

This action does not have tribal implications, as specified in Executive Order 13175 (65 FR 67249, November 9, 2000). The proposed amendments impose no requirements on tribal governments. Thus, Executive Order 13175 does not apply to this action.

EPA specifically solicits additional comment on this proposed action from tribal officials.

G. Executive Order 13045: Protection of Children From Environmental Health Risks and Safety Risks

EPA interprets Executive Order 13045 (62 FR 19885, April 23, 1997) as applying to those regulatory actions that concern health or safety risks, such that the analysis required under section 5–501 of the Executive Order has the potential to influence the regulation. This action is not subject to Executive Order 13045 because it is based solely on technology performance.

H. Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use

This proposed rule is not a “significant energy action” as defined in Executive Order 13211 (66 FR 28355, May 22, 2001) because it is not likely to have a significant adverse effect on the supply, distribution, or use of energy. The proposed amendments would not increase the level of energy consumption required for the final rule and may decrease energy requirements.

I. National Technology Transfer and Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act (NTTAA) of 1995 (Pub. L. 104–113, 15 U.S.C. 272 note) directs EPA to use voluntary consensus standards (VCS) in its regulatory activities, unless to do so would be inconsistent with applicable law or otherwise impractical. VCS are technical standards (e.g., materials specifications, test methods, sampling procedures, and business practices) that are developed or adopted by VCS bodies. NTTAA directs EPA to provide Congress, through OMB, explanations when the Agency decides not to use available and applicable VCS.

This proposed rulemaking involves technical standards. EPA proposes to use the following VCS for determining the higher heating value of fuel fed to process heaters: ASTM D240–02 (Reapproved 2007), “Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter”; ASTM D1826–94 (Reapproved 2003), “Standard Test Method for Calorific (Heating) Value of Gases in Natural Gas Range by Continuous Recording Calorimeter”; ASTM D4809–06, “Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter (Precision Method)”; ASTM D4891–89 (reapproved 2006), “Standard

Test Method for Heating Value of Gases in Natural Gas Range by Stoichiometric Combustion”; ASTM D1945–03, “Standard Method for Analysis of Natural Gas by Gas Chromatography”; and ASTM D1946–90 (reapproved 2006), “Standard Method for Analysis of Reformed Gas by Gas Chromatography.”

The EPA also proposes to use the following VCS as acceptable alternatives to Methods 2, 2A, 2B, 2C, or 2D for conducting relative accuracy evaluations of fuel gas flow monitors: American Society of Mechanical Engineers (ASME) MFC–3M–1989 (Reaffirmed 1995), “Measurement of Fluid Flow in Pipes Using Orifice, Nozzle, and Venturi”; ASME MFC–4M–1986 (Reaffirmed 2008), “Measurement of Gas Flow by Turbine Meters”; ASME MFC–5M–1986 (Reaffirmed 2006), “Measurement of Liquid Flow in Closed Conduits Using Transit-Time Ultrasonic Flowmeters”; ASME MFC–6M–1988 (Reaffirmed 2005), “Measurement of Fluid Flow in Pipes Using Vortex Flowmeters”; ASME MFC–7M–1987 (Reaffirmed 2006), “Measurement of Gas Flow by Means of Critical Flow Venturi Nozzles”; and ASME MFC–9M–1988 (Reaffirmed 2006), “Measurement of Liquid Flow in Closed Conduits by Weighing Method.”

EPA proposes to use the following VCS as acceptable alternatives to EPA Method 15A and 16A for conducting relative accuracy evaluations of monitors for reduced sulfur compounds, total sulfur compounds, and H₂S: ANSI/ASME PTC 19.10–1981, “Flue and Exhaust Gas Analyses.” The EPA proposes to use the following VCS as acceptable alternatives to EPA Method 16A for analysis of total sulfur samples: ASTM D4468–85 (Reapproved 2006), “Standard Test Method for Total Sulfur in Gaseous Fuels by Hydrogenolysis and Rateometric Colorimetry”; and ASTM D5504–08, “Standard Test Method for Determination of Sulfur Compounds in Natural Gas and Gaseous Fuels by Gas Chromatography and Chemiluminescence.”

EPA proposes to use the following VCS as acceptable alternatives to Method 18 for relative accuracy evaluations of gas composition analyzers for gas-fired process heaters: ASTM D1945–03, Standard Method for Analysis of Natural Gas by Gas Chromatography; ASTM D1946–90 (reapproved 2006), “Standard Method for Analysis of Reformed Gas by Gas Chromatography”; ASTM D6429–99 (reapproved 2004), “Standard Test Method for Determination of Gaseous Organic Compounds by Direct Interface Gas Chromatography-Mass Spectrometry”; and ASTM D6420–99

(reapproved 2004), “Standard Test Method for Determination of Gaseous Organic Compounds by Direct Interface Gas Chromatography-Mass Spectrometry (GC/MS).” However, ASTM D6420–99 is a suitable alternative to Method 18 only where:

(1) The target compound(s) are those listed in Section 1.1 of ASTM D6420–99, and

(2) The target concentration is between 150 parts per billion by volume and 100 ppmv.

For target compound(s) not listed in Section 1.1 of ASTM D6420–99, but potentially detected by mass spectrometry, the regulation specifies that the additional system continuing calibration check after each run, as detailed in Section 10.5.3 of the ASTM method, must be followed, met, documented, and submitted with the data report even if there is no moisture condenser used or the compound is not considered water soluble. For target compound(s) not listed in Section 1.1 of ASTM D6420–99, and not amenable to detection by mass spectrometry, ASTM D6420–99 does not apply.

These above-listed VCS are incorporated by reference (see § 60.17).

The EPA also proposes to use American Gas Association “Transmission Measurement Commenter Report No. 7 (Second Revision, April 1996),” and American Petroleum Institute’s “Manual of Petroleum Measurement Standards, Fifth Edition, August 2005, Chapter 22, Testing Protocol, Section 2, Differential Pressure Flow Measurement Devices,” for conducting relative accuracy evaluations of fuel gas flow monitors; Gas Processor Association (GPA) Standard 2261–00, “Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography,” for relative accuracy evaluations of gas composition analyzers for gas-fired process heaters; and GPA 2172–96, “Calculation of Gross Heating Value, Relative Density and Compressibility Factor for Natural Gas Mixtures from Compositional Analysis,” for determining the higher heating value of fuel fed to process heaters. These methods are also incorporated by reference (see § 60.17).

While the Agency has identified five VCS as being potentially applicable to this rule, we have decided not to use these VCS in this rulemaking. The use of these VCS would have been impractical because they do not meet the objectives of the standards cited in this rule. See the docket for this rule for the reasons for these determinations.

EPA welcomes comments on this aspect of the proposed rulemaking and,

specifically, invites the public to identify potentially-applicable VCS and to explain why such standards should be used in this regulation.

Under 40 CFR 60.13(i) of the NSPS General Provisions, a source may apply to EPA for permission to use alternative test methods or alternative monitoring requirements in place of any required testing methods, performance specifications, or procedures in the final rule and amendments.

J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations

Executive Order 12898 (59 FR 7629, February 16, 1994) establishes Federal executive policy on environmental justice. Its main provision directs Federal agencies, to the greatest extent practicable and permitted by law, to make environmental justice part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority populations and low-income populations in the United States.

EPA has determined that this proposed rule will not have disproportionately high and adverse human health or environmental effects on minority or low-income populations because it does not affect the level of protection provided to human health or the environment. The proposed amendments are either clarifications or compliance alternatives which will neither increase or decrease environmental protection.

List of Subjects in 40 CFR Part 60

Environmental protection, Administrative practice and procedure, Air pollution control, Incorporations by reference, Intergovernmental relations, Reporting and recordkeeping requirements.

Dated: December 12, 2008.

Stephen L. Johnson,
Administrator.

For the reasons stated in the preamble, title 40, chapter I of the Code of Federal Regulations is proposed to be amended as follows:

PART 60—[AMENDED]

1. The authority citation for part 60 continues to read as follows:

Authority: 42 U.S.C. 7401, *et seq.*

Subpart A—[Amended]

2. Section 60.17 is amended by:

- a. Revising paragraphs (a)(68) and (a)(84);
- b. Adding paragraphs (a)(93) through (a)(99);
- c. Adding paragraph (c)(2);
- d. Revising paragraph (h)(4) and adding paragraphs (h)(5) through (h)(10);
- e. Adding paragraph (m)(2) and (m)(3); and
- f. Adding paragraph (o) to read as follows:

§ 60.17 Incorporations by reference.

* * * * *

(a) * * *

(68) ASTM D4468–85 (Reapproved 2006), Standard Test Method for Total Sulfur in Gaseous Fuels by Hydrogenolysis and Rateometric Colorimetry, IBR approved for §§ 60.107a(e)(3)(v), 60.335(b)(10)(ii), 60.4415(a)(1)(ii).

* * * * *

(84) ASTM D6420–99 (Reapproved 2004) Standard Test Method for Determination of Gaseous Organic Compounds by Direct Interface Gas Chromatography-Mass Spectrometry, IBR approved for § 60.107a(d)(4)(ii) of subpart Ja and table 2 of subpart JJJJ of this part.

* * * * *

(93) ASTM D240–02, (Reapproved 2007), Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter, IBR approved for § 60.107a(d)(7)(i) of subpart Ja of this part.

(94) ASTM D1826–94 (Reapproved 2003), Standard Test Method for Calorific (Heating) Value of Gases in Natural Gas Range by Continuous Recording Calorimeter, IBR approved for § 60.107a(d)(7)(ii) of subpart Ja of this part.

(95) ASTM D4809–06, Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter (Precision Method), IBR approved for § 60.107a(d)(7)(iii) of subpart Ja of this part.

(96) ASTM D4891–89 (Reapproved 2006), Standard Test Method for Heating Value of Gases in Natural Gas Range by Stoichiometric Combustion, IBR approved for § 60.107a(d)(7)(iv) of subpart Ja of this part.

(97) ASTM D5504–08, Standard Test Method for Determination of Sulfur Compounds in Natural Gas and Gaseous Fuels by Gas Chromatography and Chemiluminescence, IBR approved for § 60.107a(e)(3)(v) of subpart Ja of this part.

(98) ASTM D1945–03, Standard Method for Analysis of Natural Gas by Gas Chromatography, IBR approved for

§ 60.107a(d)(4)(i) of subpart Ja of this part.

(9) ASTM D1946–90 (Reapproved 2006), Standard Method for Analysis of Reformed Gas by Gas Chromatography, IBR approved for § 60.107a(d)(4)(iii) of subpart Ja of this part.

* * * * *

(c) * * *

(2) Manual of Petroleum Measurement Standards, Fifth Edition, Chapter 22—Testing Protocol, Section 2, Differential Pressure Flow Measurement Devices, August 2005, IBR approved for § 60.107a(d)(5)(viii) of subpart Ja of this part.

* * * * *

(h) * * *

(4) ANSI/ASME PTC 19.10–1981, Flue and Exhaust Gas Analyses [part 10, Instruments and Apparatus], IBR approved for § 60.106(e)(2) of subpart J, §§ 60.104a(d)(3), (d)(5), (d)(6), (h)(3), (h)(4), (h)(5), (i)(3), (i)(4), (i)(5), (j)(3), and (j)(4), 60.105a(d)(4), (f)(2), (f)(4), (g)(2), and (g)(4), 60.106a(a)(1)(iii), (a)(2)(iii), (a)(2)(v), (a)(2)(viii), (a)(3)(ii), and (a)(3)(v), and 60.107a(a)(1)(ii), (a)(1)(iv), (a)(2)(ii), (c)(2), (c)(4), (d)(2), (e)(1)(ii), (e)(2)(ii), and (e)(3)(ii) of subpart Ja, tables 1 and 3 of subpart EEEE, tables 2 and 4 of subpart FFFF, table 2 of subpart JJJJ, and §§ 60.4415(a)(2) and 60.4415(a)(3) of subpart KKKK of this part.

(5) ASME MFC–3M–1989 (Reaffirmed 1995), Measurement of Fluid Flow in Pipes Using Orifice, Nozzle, and Venturi, IBR approved for § 60.107a(d)(5)(i) of subpart Ja of this part.

(6) ASME MFC–4M–1986 (Reaffirmed 2008), Measurement of Gas Flow by Turbine Meters, IBR approved for § 60.107a(d)(5)(ii) of subpart Ja of this part.

(7) ASME–MFC–5M–1986 (Reaffirmed 2006), Measurement of Liquid Flow in Closed Conduits Using Transit-Time Ultrasonic Flowmeters, IBR approved for § 60.107a(d)(5)(iii) of subpart Ja of this part.

(8) ASME MFC–6M–1998 (Reaffirmed 2005), Measurement of Fluid Flow in Pipes Using Vortex Flowmeters, IBR approved for § 60.107a(d)(5)(iv) of subpart Ja of this part.

(9) ASME MFC–7M–1987 (Reaffirmed 2006), Measurement of Gas Flow by Means of Critical Flow Venturi Nozzles, IBR approved for § 60.107a(d)(5)(v) of subpart Ja of this part.

(10) ASME MFC–9M–1988 (Reaffirmed 2006), Measurement of Liquid Flow in Closed Conduits by Weighing Method, IBR approved for § 60.107a(d)(5)(vi) of subpart Ja of this part.

* * * * *

(m) * * *

(2) Gas Processors Association Standard 2172–96, Calculation of Gross Heating Value, Relative Density and Compressibility Factor for Natural Gas Mixtures from Compositional Analysis, IBR approved for § 60.107a(d)(7)(v) of subpart Ja of this part.

(3) Gas Processors Association Standard 2261–00, Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography, IBR approved for § 60.107a(d)(4)(iv) of subpart Ja of this part.

* * * * *

(o) The following American Gas Association material is available for purchase from the following address: ILI Infodisk, 610 Winters Avenue, Paramus, New Jersey 07652:

(1) American Gas Association Transmission Measurement Committee Report No. 7: Measurement of Gas by Turbine Meters, Second Revision, April 1996, IBR approved for § 60.107a(d)(5)(vii) of subpart Ja of this part.

(2) [Reserved]

Subpart J—[Amended]

3. Section 60.100 is amended by:

- Redesignating paragraph (e) as (f); and
- Adding a new paragraph (e) to read as follows:

§ 60.100 Applicability, designation of affected facility, and reconstruction.

* * * * *

(e) Owners or operators may choose to comply with the applicable provisions of subpart Ja of this part to satisfy the requirements of this subpart for an affected facility.

* * * * *

4. Section 60.106 is amended by revising paragraph (c)(1) to read as follows:

§ 60.106 Test methods and procedures.

* * * * *

(c) * * *

(1) The allowable emission rate (E_s) of PM shall be computed for each run using the following equation:

$$E_s = F + A (H/R_c)$$

Where:

E_s = Emission rate of PM allowed, kg/Mg (lb/ton) of coke burn-off in catalyst regenerator.

F = Emission standard, 1.0 kg/Mg (2.0 lb/ton) of coke burn-off in catalyst regenerator.

A = Allowable incremental rate of PM emissions, 43 g/GJ (0.10 lb/million Btu).

H = Heat input rate from solid or liquid fossil fuel, GJ/hr (million Btu/hr).

R_c = Coke burn-off rate, Mg coke/hr (ton coke/hr).

* * * * *

Subpart Ja—[Amended]

5. Section 60.100a is amended by revising paragraph (c) introductory text and paragraph (c)(1) to read as follows:

§ 60.100a Applicability, designation of affected facility, and reconstruction.

* * * * *

(c) For all affected facilities other than flares, the provisions in § 60.14 regarding modification apply. As provided in § 60.14(f), the special provisions set forth under this subpart shall supersede the provisions in § 60.14 with respect to flares. For the purposes of this subpart, a modification to a flare occurs as provided in paragraphs (c)(1) or (2) of this section.

(1) Any new piping from a refinery process unit or fuel gas system is physically connected to the flare (e.g., for direct emergency relief or some form of continuous or intermittent venting). However, the connections described in paragraphs (c)(1)(i) through (iv) of this section are not considered modifications of a flare.

(i) Connections made to install monitoring systems to the flare.

(ii) Connections made to install a flare gas recovery system.

(iii) Connections made to replace or upgrade existing pressure relief or safety valves, provided the new pressure relief or safety valve has a set point opening pressure no lower and an internal diameter no greater than the existing equipment being replaced or upgraded.

(iv) Replacing piping or moving an existing connection from a refinery process unit to a new location in the same flare, provided the new pipe diameter is less than or equal to the diameter of the pipe/connection being replaced/moved.

* * * * *

6. Section 60.101a is amended by:

a. Adding, in alphabetical order, definitions of “Air preheat,” “Co-fired process heater,” “Corrective action,” “Corrective action analysis,” “Flare gas recovery system,” “Forced draft process heater,” “Natural draft process heater,” and “Root cause analysis”; and

b. Revising the definitions of “Delayed coking unit,” “Flexicoking unit,” “Fluid coking unit,” “Fuel gas,” “Petroleum refinery,” “Process upset gas,” “Refinery process unit” and “Sulfur recovery plant” to read as follows:

§ 60.101a Definitions.

Air preheat means a device used to heat the air supplied to a process heater generally by use of a heat exchanger to recover the latent heat of exhaust gas from the process heater.

Co-fired process heater means a process heater that employs burners that are designed to be supplied by both gaseous and liquid fuels.

Corrective action means the design, operation, and maintenance changes consistent with good engineering practice to reduce or eliminate the likelihood of recurrence of an event identified by a root cause analysis as having caused a discharge of gases to an affected flare in excess of the flow rate threshold in § 60.103a(a)(4) or the discharge of gases from an affected fuel gas combustion device or sulfur recovery plant in excess of the applicable SO₂ threshold in § 60.103a(b).

Corrective action analysis means a description of all reasonable interim and long-term measures, if any, that are available, and an explanation of why the selected *corrective action* is the best alternative, including any consideration of cost-effectiveness.

Delayed coking unit means a refinery process unit in which high molecular weight petroleum derivatives are thermally cracked and petroleum coke is produced in a series of closed, batch system reactors. A delayed coking unit consists of the coke drums and associated fractionator.

* * * * *

Flare gas recovery system means a system of one or more compressors, piping, and associated water seal, rupture disk, or similar device used to divert gas from the flare and direct the gas to the fuel gas system or to a fuel gas combustion device other than a flare.

Flexicoking unit means a refinery process unit in which high molecular weight petroleum derivatives are thermally cracked and petroleum coke is continuously produced and then gasified to produce a synthetic fuel gas.

* * * * *

Fluid coking unit means a refinery process unit in which high molecular weight petroleum derivatives are thermally cracked and petroleum coke is continuously produced in a fluidized bed system. The *fluid coking unit* includes the coking reactor, the coking burner, and equipment for controlling air pollutant emissions and for heat recovery on the fluid coking burner exhaust vent.

Forced draft process heater means a process heater in which the combustion air is supplied under positive pressure produced by a fan at any location in the inlet air line prior to the point where the combustion air enters the process heater or air preheat.

* * * * *

Fuel gas means any gas which is generated at a petroleum refinery and which is combusted. *Fuel gas* includes natural gas when natural gas is combusted in any proportion with a gas generated at a refinery. *Fuel gas* does not include gases generated by catalytic cracking unit catalyst regenerators, coke calciners (used to make anode grade coke) and fluid coking burners, but does include gases from flexicoking unit gasifiers and other gasifiers. *Fuel gas* does not include vapors that are collected and combusted to comply with the wastewater provisions in § 40 CFR 61.343 through 61.348, 40 CFR 63.647 or the marine tank vessel loading provisions in 40 CFR 63.652 or 40 CFR 63.651.

Natural draft process heater means any process heater in which the combustion air is supplied under ambient pressure without the use of an inlet air (forced draft) fan. For the purposes of this subpart, a *natural draft process heater* is any process heater that is not a forced draft process heater.

* * * * *

Petroleum refinery means any facility engaged in producing gasoline, kerosene, distillate fuel oils, residual fuel oils, lubricants, asphalt (bitumen) or other products through distillation of petroleum or through redistillation, cracking, or reforming of unfinished petroleum derivatives. A facility that produces only oil shale or tar sands-derived crude oil for further processing at a petroleum refinery using only solvent extraction and/or distillation to recover diluent is not a *petroleum refinery*.

* * * * *

Process upset gas means any gas generated by a petroleum refinery process unit as a result of start-up, shutdown, upset or malfunction.

* * * * *

Refinery process unit means any segment of the petroleum refinery in which a specific processing operation is conducted, including but not limited to distillation, cracking, coking, reforming, alkylation, isomerization, coke gasification, product loading, sulfur recovery, and wastewater treatment.

Root cause analysis means an assessment to determine the primary cause and any other significant contributing cause(s), as determined through a process of investigation, of discharge of gases to an affected flare in excess of the flow rate threshold in § 60.103a(a)(4) or in excess of the applicable SO₂ threshold in § 60.103a(b)(1), or the discharge of gases from an affected fuel gas combustion device or sulfur recovery plant in excess

of the applicable SO₂ thresholds in § 60.103a(b)(2) and (3).

* * * * *

Sulfur recovery plant means all refinery process units which recover sulfur from H₂S and/or SO₂ from a common source of sour gas at a petroleum refinery. The *sulfur recovery plant* also includes sulfur pits used to store the recovered sulfur product, but it does not include secondary sulfur storage vessels downstream of the sulfur pits. For example, a Claus sulfur recovery plant includes: Reactor furnace and waste heat boiler, catalytic reactors, sulfur pits, and, if present, oxidation or reduction control systems, or incinerator, thermal oxidizer, or similar combustion device. Multiple sulfur recovery plants are a single affected facility only when the units share the same source of sour gas. *Sulfur recovery plants* that receive source gas from completely segregated sour gas treatment systems are separate affected facilities.

7. Section 60.102a is amended by:

- a. Revising paragraph (a);
- b. Revising paragraph (f)(1)(ii);
- c. Revising paragraph (g) introductory text;
- d. Revising paragraph (g)(1)(ii);
- e. Revising paragraph (g)(2);
- f. Removing paragraph (g)(3); and
- g. Revising paragraph (i) to read as follows:

§ 60.102a Emissions limitations.

(a) Each owner or operator that is subject to the requirements of this subpart shall comply with the emissions limitations in paragraphs (b) through (i) of this section on and after the date on which the initial performance test, required by § 60.8, is completed, but not later than 60 days after achieving the maximum production rate at which the affected facility will be operated, or 180 days after initial startup, whichever comes first.

* * * * *

(f) * * *

(1) * * *

(ii) For a sulfur recovery plant with a reduction control system not followed by incineration, the owner or operator shall not discharge or cause the discharge of any gases into the atmosphere in excess of 300 ppmv of reduced sulfur compounds and 10 ppmv of hydrogen sulfide (H₂S), each calculated as ppmv SO₂ (dry basis) at 0 percent excess air; or

* * * * *

(g) Each owner or operator of an affected fuel gas combustion device shall comply with the emission limits in paragraphs (g)(1) and (2) of this section.

(1) * * *

(ii) The owner or operator shall not burn in any fuel gas combustion device any fuel gas that contains H₂S in excess of 162 ppmv determined hourly on a 3-hour rolling average basis and H₂S in excess of 60 ppmv determined daily on a 365 successive calendar day rolling average basis. An owner or operator of a modified flare that needs to install additional amine scrubbing and amine stripping columns to comply with the long-term H₂S limit shall comply with the 60 ppmv 365-day H₂S concentration limit no later than 2 years after that flare becomes an affected facility subject to this subpart.

(2) For each process heater with a rated capacity of greater than 40 million British thermal units per hour (MMBtu/hr) on a higher heating value basis, the owner or operator shall not discharge to

the atmosphere any emissions of NO_x in excess of the applicable limits in paragraphs (g)(2)(i) through (g)(2)(iv).

(i) For each newly constructed, modified, or reconstructed natural draft process heater:

(A) 40 ppmv (dry basis, corrected to 0 percent excess air) determined daily on a 365 successive operating day rolling average basis; or

(B) 0.035 pounds per million British thermal units (lb/MMBtu) determined daily on a 365 successive operating day rolling average basis.

(ii) For each new forced draft process heater:

(A) 40 ppmv (dry basis, corrected to 0 percent excess air) determined daily on a 365 successive operating day rolling average basis; or

(B) 0.035 lb/MMBtu determined daily on a 365 successive operating day rolling average basis.

(iii) For each modified or reconstructed forced draft process heater:

(A) 60 ppmv (dry basis, corrected to 0 percent excess air) determined daily on a 365 successive operating day rolling average basis; or

(B) 0.055 lb/MMBtu determined daily on a 365 successive operating day rolling average basis.

(iv) For each co-fired process heater:

(A) 150 ppmv (dry basis, corrected to 0 percent excess air) determined daily on a 365 successive operating day rolling average basis (applicable only when the process heater is being co-fired); or

(B) The daily average emission limit calculated using Equation 3 of this section:

$$E_{NOx, hour} = \frac{0.08Q_{gas} HHV_{gas} + 0.27Q_{oil} HHV_{oil}}{Q_{gas} HHV_{gas} + Q_{oil} HHV_{oil}} \quad (\text{Eq. 3})$$

Where:

$E_{NOx, hour}$ = Daily average emission rate of NO_x, lb/MMBtu (higher heating value basis);

Q_{gas} = Daily average volumetric flow rate of fuel gas, scf/hr;

Q_{oil} = Daily average volumetric flow rate of fuel oil, scf/hr;

HHV_{gas} = Daily average higher heating value of gas fired to the process heater, MMBtu/scf; and

HHV_{oil} = Daily average higher heating value of fuel oil fired to the process heater, MMBtu/scf.

* * * * *

(i) For a modified or reconstructed process heater that lacks sufficient space to accommodate combustion modification-based technology, or for a co-fired process heater, the owner or operator may petition the Administrator within 90 days after initial startup of the process heater for approval of a NO_x emissions limit which shall apply specifically to that affected facility. The petition shall include sufficient and appropriate data, as determined by the Administrator, to allow the Administrator to confirm that the process heater is unable to comply with the applicable NO_x emission limit in paragraph (g)(2) of this section. If the petition is approved by the Administrator, a facility-specific NO_x emissions limit will be established at the NO_x emission level achievable when the affected facility is operating in a manner that the Administrator determines to be consistent with minimizing NO_x emissions. At a

minimum, the petition shall contain the information described in paragraphs (i)(1) through (4) of this section.

(1) The design and dimensions of the process heater, evaluation of available combustion modification-based technology, description of fuel gas and, if applicable, fuel oil characteristics and combustion conditions, and any other data determined by the Administrator as appropriate.

(2) An explanation of how the data in paragraph (i)(1) demonstrate that ultra-low NO_x burners or other means cannot be used to meet the applicable emission limit in paragraph (g)(2) of this section.

(3) Results of a performance test conducted under representative conditions using the applicable methods specified in § 60.104a(i) to demonstrate the performance of the technology the owner or operator will use to minimize NO_x emissions.

(4) The means by which the owner or operator will document continuous compliance with the site-specific emissions limit.

8. Section 60.103a is amended by:

a. Revising paragraph (a) introductory text and paragraphs (a)(1), (a)(4), (a)(5), and (a)(6);

b. Revising paragraph (b);

c. Redesignating paragraph (c) as paragraph (d); and

d. Adding a new paragraph (c) to read as follows:

§ 60.103a Work practice standards.

(a) Each owner or operator that operates a flare that is subject to this

subpart shall develop and implement a written flare management plan. The owner or operator of a newly constructed or reconstructed flare must develop and implement the flare management plan by no later than the date that flare becomes an affected flare subject to this subpart. The owner or operator of a modified flare must develop and implement the flare management plan by no later than 18 months after the flare becomes an affected flare subject to this subpart unless the owner or operator of the affected flare commits in writing to install a flare gas recovery system, in which case the owner or operator of a modified flare must develop and implement the flare management plan by no later than 2 years after the flare becomes an affected flare subject to this subpart. The plan must include:

(1) A listing of all refinery process units and fuel gas systems connected to the flare for each affected flare and an assessment of whether discharges to affected flares from these process units and fuel gas systems can be minimized;

* * * * *

(4) Procedures to conduct a root cause analysis as soon as possible but no later than 45 days after any discharge to the flare in excess of 14,160 standard cubic meters (m³) (500,000 standard cubic feet (scf)) in any 24-hour period. The first root cause analysis and corrective action analysis for a modified flare must be conducted no later than the first discharge triggering a root cause

analysis that occurs after the flare has been an affected flare subject to this subpart for 18 months, unless the owner or operator of the affected flare commits in writing to install a flare gas recovery system, in which case the flow rate root cause analysis for a modified flare must be conducted no later than the first discharge triggering a flow rate root cause analysis that occurs after the flare has been an affected flare subject to this subpart for 2 years;

(5) Procedures to conduct a corrective action analysis and implement corrective actions as soon as possible but no later than 45 days after a discharge exceeding the flow rate threshold in paragraph (a)(4) of this section to minimize the recurrence of similarly caused events based on the finding of the root cause analysis required under paragraph (a)(4) of this section; and

(6) Procedures to reduce flaring in cases of fuel gas imbalance (i.e., excess fuel gas for the refinery's energy needs).

(b) Each owner or operator that operates a fuel gas combustion device or sulfur recovery plant subject to this subpart shall conduct a root cause analysis and a corrective action analysis under each of the conditions specified in paragraphs (b)(1) through (3) of this section and implement corrective actions to minimize the recurrence of a similarly caused event. If a single continuous discharge causes emissions to exceed a level specified in paragraphs (b)(1) through (3) of this section for 2 or more consecutive 24-hour periods, a single root cause analysis may be conducted. For any root cause analysis and corrective action analysis performed, and for any corrective action taken, the owner or operator shall, as soon as possible but no later than 45 days after the discharge, record the identification of the affected facility, the date and duration of the discharge, a

description of the root cause of the discharge as identified by the root cause analysis, results of the corrective action analysis, and the corrective action taken as a result of the root cause analysis, as specified in § 60.108a(c)(6).

(1) For a flare, conduct a root cause analysis and a corrective action analysis and take corrective action each time the SO₂ emissions exceed 227 kilograms (kg) (500 pounds (lb)) in any 24-hour period. The first root cause analysis and corrective action analysis for a modified flare must be conducted no later than the first discharge of SO₂ triggering a root cause analysis that occurs after the flare has been an affected flare subject to this subpart for 18 months, unless the owner or operator of the affected flare commits in writing to install a flare gas recovery system, in which case the root cause analysis for a modified flare must be conducted no later than the first discharge of SO₂ triggering a root cause analysis that occurs after the flare has been an affected flare subject to this subpart for 2 years.

(2) For any fuel gas combustion device other than a flare, conduct a root cause analysis and a corrective action analysis and take corrective action for each exceedance of an applicable short-term emissions limit in § 60.102a(g)(1) if the SO₂ discharge to the atmosphere is 227 kg (500 lb) greater than the amount that would have been emitted if the emissions limits had been met during the period of the exceedance.

(3) For a sulfur recovery plant, conduct a root cause analysis and a corrective action analysis and take corrective action when the daily SO₂ emissions are more than 227 kg (500 lb) greater than the amount that would have been emitted if the SO₂ or reduced sulfur concentration was equal to the applicable emission limit in § 60.102a(f)(1) or (2) for the entire 24-hour period.

(c) When an owner or operator implements corrective action(s) as specified by paragraphs (a)(5) and (b) of this section, the owner or operator shall, no later than 45 days following the discharge, record a description of the action(s) and, if not already completed, a schedule for its (their) implementation, including proposed commencement and completion dates. If an owner or operator concludes that corrective action should not be conducted, the owner or operator shall record and explain the basis for that conclusion no later than 45 days following the discharge.

* * * * *

9. Section 60.104a is amended by:

- a. Revising paragraphs (d)(4)(ii), (d)(4)(iii), (d)(4)(v), and (d)(8);
- b. Adding paragraph (e)(3); and
- c. Revising paragraph (h)(5)(iv) to read as follows:

§ 60.104a Performance tests.

* * * * *

(d) * * *

(4) * * *

(ii) The emissions rate of PM (E_{PM}) is computed for each run using Equation 4 of this section:

$$E = \frac{c_s Q_{sd}}{K R_c} \quad (\text{Eq. 4})$$

Where:

E = Emission rate of PM, g/kg, lb per 1,000 lb (lb/1,000 lb) of coke burn-off;

c_s = Concentration of total PM, grams per dry standard cubic meter (g/dscm), gr/dscf;

Q_{sd} = Volumetric flow rate of effluent gas, dry standard cubic meters per hour, dry standard cubic feet per hour;

R_c = Coke burn-off rate, kilograms per hour (kg/hr), lb per hour (lb/hr) coke; and

K = Conversion factor, 1.0 grams per gram (7,000 grains per lb).

(iii) The coke burn-off rate (R_c) is computed for each run using Equation 5 of this section:

$$R_c = K_1 Q_r (\%CO_2 + \%CO) + K_2 Q_a - K_3 Q_r (\%CO_2 / 2 + \%CO_2 + \%O_2) + K_3 Q_{oxy} (\%O_{oxy}) \quad (\text{Eq. 5})$$

R_c = Coke burn-off rate, kg/hr (lb/hr);

Q_r = Volumetric flow rate of exhaust gas from FCCU regenerator or fluid coking burner before any emissions control or energy recovery system that burns auxiliary fuel, dry standard cubic meters per minute (dscm/min), dry standard cubic feet per minute (dscf/min);

Q_a = Volumetric flow rate of air to FCCU regenerator or fluid coking burner, as determined from the unit's control room instrumentation, dscm/min (dscf/min);

Q_{oxy} = Volumetric flow rate of O₂ enriched air to FCCU regenerator or fluid coking unit, as determined from the unit's

control room instrumentation, dscm/min (dscf/min);

%CO₂ = Carbon dioxide concentration in FCCU regenerator or fluid coking burner exhaust, percent by volume (dry basis);

%CO = CO concentration in FCCU regenerator or fluid coking burner exhaust, percent by volume (dry basis);

%O₂ = O₂ concentration in FCCU regenerator or fluid coking burner exhaust, percent by volume (dry basis);

%O_{oxy} = O₂ concentration in O₂ enriched air stream inlet to the FCCU regenerator or fluid coking burner, percent by volume (dry basis);

K₁ = Material balance and conversion factor, 0.2982 (kg-min)/(hr-dscm-%) [0.0186 (lb-min)/(hr-dscf-%)];

K₂ = Material balance and conversion factor, 2.088 (kg-min)/(hr-dscm) [0.1303 (lb-min)/(hr-dscf)]; and

K₃ = Material balance and conversion factor, 0.0994 (kg-min)/(hr-dscm-%) [0.00624 (lb-min)/(hr-dscf-%)].

* * * * *

(v) For subsequent calculations of coke burn-off rates or exhaust gas flow rates, the volumetric flow rate of Q_r is calculated using average exhaust gas

concentrations as measured by the monitors required in § 60.105a(b)(2), if

applicable, using Equation 6 of this section:

$$Q_r = \frac{79 \times Q_a + (100 - \%O_{oxy}) \times Q_{oxy}}{100 - \%CO_2 - \%CO - \%O_2} \quad (\text{Eq. 6})$$

Where:

Q_r = Volumetric flow rate of exhaust gas from FCCU regenerator or fluid coking burner before any emission control or energy recovery system that burns auxiliary fuel, dscm/min (dscf/min);

Q_a = Volumetric flow rate of air to FCCU regenerator or fluid coking burner, as determined from the unit's control room instrumentation, dscm/min (dscf/min);

Q_{oxy} = Volumetric flow rate of O₂ enriched air to FCCU regenerator or fluid coking unit, as determined from the unit's control room instrumentation, dscm/min (dscf/min);

$\%CO_2$ = Carbon dioxide concentration in FCCU regenerator or fluid coking burner exhaust, percent by volume (dry basis);

$\%CO$ = CO concentration FCCU regenerator or fluid coking burner exhaust, percent

by volume (dry basis). When no auxiliary fuel is burned and a continuous CO monitor is not required in accordance with § 60.105a(g)(3), assume %CO to be zero;

$\%O_2$ = O₂ concentration in FCCU regenerator or fluid coking burner exhaust, percent by volume (dry basis); and

$\%O_{oxy}$ = O₂ concentration in O₂ enriched air stream inlet to the FCCU regenerator or fluid coking burner, percent by volume (dry basis).

* * * * *

(8) The owner or operator shall adjust PM, NO_x, SO₂, and CO pollutant concentrations to 0 percent excess air or 0 percent O₂ using Equation 7 of this section:

$$\text{Opacity Limit} = \text{Opacity}_{st} \times \left(\frac{1 \text{ lb}/1,000 \text{ lb coke burn}}{\text{PME}R_{st}} \right) \quad (\text{Eq. 8})$$

Where:

Opacity limit = Maximum permissible hourly average opacity, percent, or 10 percent, whichever is greater;

Opacity_{st} = Hourly average opacity measured during the source test runs, percent; and
PME_{st} = PM emission rate measured during the source test, lb/1,000 lb coke burn.

* * * * *

(h) * * *

(5) * * *

(iv) The owner or operator shall use Equation 7 of this section to adjust pollutant concentrations to 0 percent O₂ or 0 percent excess air.

* * * * *

10. Section 60.105a is amended by:

a. Revising paragraph (b) introductory text and paragraphs (b)(2)(i) and (b)(2)(ii); and

b. Revising paragraph (i)(5) to read as follows:

§ 60.105a Monitoring of emissions and operations for fluid catalytic cracking units (FCCU) and fluid coking units (FCU).

* * * * *

(b) *Control device operating parameters.* Each owner or operator of a FCCU or FCU subject to the PM per coke burn-off emissions limit in § 60.102a(b)(1) shall comply with the requirements in paragraphs (b)(1) and (2) of this section.

* * * * *

(2) * * *

(i) The owner or operator shall install, operate, and maintain each monitor according to Performance Specifications 3 and 4 of Appendix B to part 60.

(ii) The owner or operator shall conduct performance evaluations of each CO₂, O₂, and CO monitor according to the requirements in § 60.13(c) and Performance Specifications 3 and 4 of Appendix B to part 60. The owner or operator shall use Method 3 of Appendix A–3 to part 60 and Method 10, 10A, or 10B of Appendix A–4 to part 60 for conducting the relative accuracy evaluations.

* * * * *

(i) * * *

(5) All rolling 7-day periods during which the average concentration of SO₂ as measured by the SO₂ CEMS under § 60.105a(g) exceeds 50 ppmv, and all rolling 365-day periods during which the average concentration of SO₂ as measured by the SO₂ CEMS exceeds 25 ppmv.

* * * * *

11. Section 60.107a is amended by:

a. Revising the section heading;
b. Revising paragraph (a)(2)(i);
c. Revising paragraph (c) introductory text and paragraphs (c)(1) and (c)(6);
d. Redesignating paragraphs (d), (e), and (f) as paragraphs (e), (f), and (g), respectively;

$$C_{adj} = C_{meas} \left[\frac{20.9_c}{(20.9 - \%O_2)} \right] \quad (\text{Eq. 7})$$

Where:

C_{adj} = pollutant concentration adjusted to 0 percent excess air or O₂, parts per million (ppm) or g/dscm;

C_{meas} = pollutant concentration measured on a dry basis, ppm or g/dscm;

20.9_c = 20.9 percent O₂–0.0 percent O₂

(defined O₂ correction basis), percent;

20.9 = O₂ concentration in air, percent; and

$\%O_2$ = O₂ concentration measured on a dry basis, percent.

(e) * * *

(3) Compute the site-specific limit using Equation 8 of this section:

e. Adding a new paragraph (d);

f. Revising newly redesignated paragraph (e);

g. Revising newly redesignated paragraph (f) introductory text; and

h. Revising newly redesignated paragraphs (g)(3) and (g)(4) to read as follows:

§ 60.107a Monitoring of emissions and operations for process heaters and other fuel gas combustion devices.

(a) * * *

(2) * * *

(i) The owner or operator shall install, operate, and maintain each H₂S monitor according to Performance Specification 7 of Appendix B to part 60. The span value for this instrument is 300 ppmv H₂S.

* * * * *

(c) *Process heaters complying with the NO_x concentration-based limit.* The owner or operator of a process heater subject to the NO_x emission limit in § 60.102a(g)(2) and electing to comply with the applicable emission limit in § 60.102a(g)(2)(i)(A), (g)(2)(ii)(A), (g)(2)(iii)(A), or (g)(2)(iv)(A) shall install, operate, calibrate, and maintain an instrument for continuously monitoring and recording the concentration (dry basis, 0 percent excess air) of NO_x emissions into the atmosphere according to the requirements in paragraphs (c)(1) through (5) of this

section, except as provided in paragraph (c)(6) of this section. The monitor must include an O₂ monitor for correcting the data for excess air.

(1) The owner or operator shall install, operate, and maintain each NO_x monitor according to Performance Specification 2 of Appendix B to part 60. The span value of this NO_x monitor must be between 2 and 3 times the applicable emission limit, inclusive.

* * * * *

(6) The owner or operator of a process heater that has a rated heating capacity of less than 100 MMBtu and is equipped with combustion modification-based technology to reduce NO_x emissions (i.e., low-NO_x burners, ultra-low-NO_x burners) may elect to comply with the monitoring requirements in paragraphs (c)(1) through (5) of this section or, alternatively, the owner or operator of such a process heater shall conduct biennial performance tests, establish a maximum excess oxygen concentration operating limit, and comply with the O₂ monitoring requirements in paragraphs (c)(3) through (5) of this section to demonstrate compliance.

(d) *Process heaters complying with the NO_x heating value-based limit.* The owner or operator of a process heater subject to the NO_x emissions limit in § 60.102a(g)(2) and electing to comply with the applicable emissions limit in § 60.102a(g)(2)(i)(B), (g)(2)(ii)(B), or (g)(2)(iii)(B) shall install, operate, calibrate, and maintain an instrument for continuously monitoring and recording the concentration (dry basis, 0 percent excess air) of NO_x emissions into the atmosphere and shall determine the F factor of the fuel gas stream no less frequently than once per day according to the monitoring requirements in paragraphs (d)(1) through (4) of this section. The owner or operator of a co-fired process heater subject to the NO_x emission limit in § 60.102a(g)(2) and electing to comply with the heating value-based limit in § 60.102a(g)(2)(iv)(B) shall also install, operate, calibrate, and maintain an instrument for continuously monitoring and recording the concentration (dry basis, 0 percent excess air) of NO_x emissions into the atmosphere according to the monitoring requirements in paragraph (d)(1) of this section, an instrument for continuously monitoring and recording the flow rate of the fuel oil and fuel gas fed to the process heater according to the monitoring requirements in paragraph (d)(5) and (6) of this section, and shall determine the heating value of the fuel oil and fuel gas streams no less frequently than once per day according

to the monitoring requirements in paragraph (d)(7) of this section.

(1) The owner or operator shall install, operate, and maintain each NO_x monitor according to the requirements in paragraphs (c)(1) through (5) of this section. The monitor must include an O₂ monitor for correcting the data for excess air.

(2) Except as provided in paragraph (d)(3) of this section, the owner or operator shall sample and analyze each fuel stream fed to the process heater using the methods and equations in section 12.3.2 of Method 19 of Appendix A-7 to part 60 to determine the F factor on a dry basis. If a single fuel gas system provides fuel gas to several process heaters, the F factor may be determined at a single location in the fuel gas system provided it is representative of the fuel gas fed to the affected process heater(s).

(3) As an alternative to the requirements in paragraph (d)(2) of this section, the owner or operator of a gas-fired process heater shall install, operate, and maintain a gas composition analyzer and determine the average F factor of the fuel gas using the factors in Table 1 of this subpart and Equation 9 of this section. If a single fuel gas system provides fuel gas to several process heaters, the F factor may be determined at a single location in the fuel gas system provided it is representative of the fuel gas fed to the affected process heater(s).

$$F_d = \frac{1,000,000 \times \sum (X_i \times MEV_i)}{\sum (X_i \times MHC_i)} \quad (\text{Eq. 9})$$

Where:

F_d = F factor on dry basis at 0% excess air.

X_i = mole or volume fraction of each component in the fuel gas.

MEV_i = molar exhaust volume, dry standard cubic feet per mole (dscf/mol).

MHC_i = molar heat content, Btu per mole (Btu/mol).

1,000,000 = unit conversion, Btu per MMBtu.

(4) The owner or operator shall conduct performance evaluations of each compositional monitor according to the requirements in Performance Specification 9 of Appendix B to part 60. Method 18 of Appendix A-6 to part 60 shall be used for conducting the relative accuracy evaluations. The following methods are acceptable alternatives to EPA Method 18 of Appendix A-2 to part 60:

(i) ASTM D1945-03, Standard Method for Analysis of Natural Gas by Gas Chromatography (incorporated by reference-see § 60.17);

(ii) ASTM D6420-99 (Reapproved 2004) Standard Test Method for Determination of Gaseous Organic

Compounds by Direct Interface Gas Chromatography-Mass Spectrometry (incorporated by reference-see § 60.17);

(iii) ASTM D1946-90 (Reapproved 2006), Standard Method for Analysis of Reformulated Gas by Gas Chromatography (incorporated by reference-see § 60.17); and

(iv) Gas Processors Association Standard 2261-00, Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography (incorporated by reference-see § 60.17).

(5) The owner or operator shall conduct performance evaluations of each fuel gas flow monitor according to the requirements in § 60.13(c) and Performance Specification 6 of Appendix B to part 60. Method 2, 2A, 2B, 2C, or 2D of Appendix A-2 to part 60 shall be used for conducting the relative accuracy evaluations. The following methods are acceptable alternatives to EPA Method 2, 2A, 2B, 2C, or 2D of Appendix A-2 to part 60:

(i) ASME MFC-3M-1989 (Reaffirmed 1995), Measurement of Fluid Flow in Pipes Using Orifice, Nozzle, and Venturi (incorporated by reference-see § 60.17);

(ii) ASME MFC-4M-1986 (Reaffirmed 1997), Measurement of Gas Flow by Turbine Meters (incorporated by reference-see § 60.17);

(iii) ASME-MFC-5M-1985, (Reaffirmed 1994), Measurement of Liquid Flow in Closed Conduits Using Transit-Time Ultrasonic Flowmeters (incorporated by reference-see § 60.17);

(iv) ASME MFC-6M-1998, Measurement of Fluid Flow in Pipes Using Vortex Flowmeters (incorporated by reference-see § 60.17);

(v) ASME MFC-7M-1987 (Reaffirmed 1992), Measurement of Gas Flow by Means of Critical Flow Venturi Nozzles (incorporated by reference-see § 60.17);

(vi) ASME MFC-9M-1988

(Reaffirmed 2001), Measurement of Liquid Flow in Closed Conduits by Weighing Method (incorporated by reference-see § 60.17);

(vii) American Gas Association Transmission Measurement Committee Report No. 7: Measurement of Gas by Turbine Meters Second Revision, April 1996 (incorporated by reference-see § 60.17); and

(viii) American Petroleum Institute (API) Manual of Petroleum Measurement Standards, First Edition, Chapter 22-Testing Protocol, Section 2-Differential Pressure Flow Measurement Devices, August 2005 (incorporated by reference-see § 60.17).

(6) The owner or operator shall conduct install, operate, and maintain each fuel oil flow monitor according to the manufacturer's recommendations.

(7) The owner or operator shall determine the higher heating value of each fuel fed to the process heater using any of the applicable methods included in paragraphs (d)(7)(i) through (v) of this section. If a common fuel supply system provides fuel gas or fuel oil to several process heaters, the higher heating value of the fuel in each fuel supply system may be determined at a single location in the fuel supply system provided it is representative of the fuel fed to the affected process heater(s).

(i) ASTM D240–02, (Reapproved 2007), Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter (incorporated by reference—see § 60.17).

(ii) ASTM D1826–94 (Reapproved 2003), Standard Test Method for Calorific (Heating) Value of Gases in Natural Gas Range by Continuous Recording Calorimeter (incorporated by reference—see § 60.17).

(iii) ASTM D4809–06, Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter (Precision Method) (incorporated by reference—see § 60.17).

(iv) ASTM D4891–89 (Reapproved 2006), Standard Test Method for Heating Value of Gases in Natural Gas Range by Stoichiometric Combustion (incorporated by reference—see § 60.17).

(v) Gas Processors Association Standard 2172–96, Calculation of Gross Heating Value, Relative Density and Compressibility Factor for Natural Gas Mixtures from Compositional Analysis (incorporated by reference—see § 60.17).

(8) The owner or operator of a process heater that has a rated heating capacity of less than 100 MMBtu and is equipped with combustion modification based technology to reduce NO_x emissions (i.e., low-NO_x burners or ultra-low NO_x burners) may elect to comply with the monitoring requirements in paragraphs (d)(1) through (7) of this section or, alternatively, the owner or operator of such a process heater shall conduct biennial performance tests, establish a maximum excess oxygen concentration operating limit, and comply with the O₂ monitoring requirements in paragraphs (c)(3) through (5) of this section to demonstrate compliance.

(e) *Sulfur monitoring for affected flares.* The owner or operator of an affected flare subject to § 60.103a(b) shall determine reduced sulfur compound concentrations in accordance with paragraph (e)(1) of this section or total sulfur compound concentrations in accordance with either paragraph (e)(2) or (3) of this section.

(1) The owner or operator shall install, operate, calibrate, and maintain an instrument for continuously

monitoring and recording the concentration of reduced sulfur compounds in flare gas. The owner or operator of a modified flare must install this instrument no later than 18 months after the flare becomes an affected flare subject to this subpart unless the owner or operator of the affected flare commits in writing to install a flare gas recovery system, in which case the owner or operator of a modified flare must install this instrument no later than 2 years after the flare becomes an affected flare subject to this subpart.

(i) The owner or operator shall install, operate, and maintain each reduced sulfur compounds CEMS according to Performance Specification 5 of Appendix B to part 60.

(ii) The owner or operator shall conduct performance evaluations of each reduced sulfur compounds monitor according to the requirements in § 60.13(c) and Performance Specification 5 of Appendix B to part 60. The owner or operator shall use Method 15 or 15A of Appendix A–5 to part 60 for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10–1981, “Flue and Exhaust Gas Analyses,” (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 15A of Appendix A–5 to part 60.

(iii) The owner or operator shall comply with the applicable quality assurance procedures in Appendix F to part 60 for each reduced sulfur monitor.

(2) The owner or operator shall install, operate, calibrate, and maintain an instrument for continuously monitoring and recording the concentration of total sulfur compounds in flare gas. The owner or operator of a modified flare must install this instrument no later than 18 months after the flare becomes an affected flare subject to this subpart unless the owner or operator of the affected flare commits in writing to install a flare gas recovery system, in which case the owner or operator of a modified flare must install this instrument no later than 2 years after the flare becomes an affected flare subject to this subpart.

(i) The owner or operator shall install, operate, and maintain each total sulfur compounds CEMS according to Performance Specification 5 of Appendix B to part 60.

(ii) The owner or operator shall conduct performance evaluations of each total sulfur compounds monitor according to the requirements in § 60.13(c) and Performance Specification 5 of Appendix B to part 60. The owner or operator shall use Method 16 or 16A of Appendix A–6 to

part 60 for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10–1981, “Flue and Exhaust Gas Analyses,” (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 16A of Appendix A–6 to part 60.

(iii) The owner or operator shall comply with the applicable quality assurance procedures in Appendix F to part 60 for each reduced sulfur monitor.

(3) The owner or operator shall install, operate, calibrate, and maintain an instrument for continuously monitoring and recording the concentration of H₂S in flare gas according to the requirements in paragraphs (e)(3)(i) through (iii) of this section and shall collect and analyze samples of flare gas and calculate total sulfur concentrations as specified in paragraphs (e)(3)(iv) through (ix) of this section. The owner or operator of a modified flare must install this H₂S monitor no later than 18 months after the flare becomes an affected flare subject to this subpart unless the owner or operator of the affected flare commits in writing to install a flare gas recovery system, in which case the owner or operator of a modified flare must install this instrument no later than 2 years after the flare becomes an affected flare subject to this subpart.

(i) The owner or operator shall install, operate, and maintain each H₂S monitor according to Performance Specification 7 of Appendix B to part 60. The span value must be between 1 and 5 percent (by volume) inclusive. A single dual range H₂S monitor may be used to comply with the requirements of this paragraph and paragraph (a)(2) of this section provided the applicable span specifications are met.

(ii) The owner or operator shall conduct performance evaluations of each H₂S monitor according to the requirements in § 60.13(c) and Performance Specification 7 of Appendix B to part 60. The owner or operator shall use Method 11, 15, or 15A of Appendix A–5 to part 60 for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10–1981, “Flue and Exhaust Gas Analyses,” (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 15A of Appendix A–5 to part 60.

(iii) The owner or operator shall comply with the applicable quality assurance procedures in Appendix F to part 60 for each H₂S monitor.

(iv) In the first 10 operating days after the flare may be required to perform a root cause analysis under § 60.103a(b)(1), the owner or operator

shall collect representative daily samples of the flare gas. The samples may be grab samples or integrated samples. The owner or operator shall take subsequent representative daily samples at least once per week or as required in paragraph (e)(3)(vii) of this section.

(v) The owner or operator shall analyze each daily sample for total sulfur using Method 16A of Appendix A-6 to part 60, ASTM Method D4468-85 (Reapproved 2006), "Standard Test Method for Total Sulfur in Gaseous Fuels by Hydrogenolysis and Ratemetric Colorimetry" (incorporated by reference—see § 60.17), or ASTM Method D5504-01 (Reapproved 2006), "Standard Test Method for Determination of Sulfur Compounds in Natural Gas and Gaseous Fuels by Gas Chromatography and Chemiluminescence" (incorporated by reference—see § 60.17).

(vi) The owner or operator shall develop a 10-day average total sulfur-to-H₂S ratio and 95 percent confidence interval as follows:

(A) Calculate the ratio of the total sulfur concentration to the H₂S concentration for each day during which samples are collected.

(B) Determine the 10-day average total sulfur-to-H₂S ratio as the arithmetic average of the daily ratios calculated in paragraph (e)(3)(vi)(A) of this section.

(C) Determine the 95 percent confidence interval for the distribution of daily ratios based on the 10 individual daily ratios.

(vii) For each day during the period when data are being collected to develop a 10-day average, the owner or operator shall estimate the total sulfur concentration using the measured total sulfur concentration measured for that day.

(viii) For all days other than those during which data are being collected to develop a 10-day average, the owner or operator shall multiply the most recent 10-day average total sulfur-to-H₂S ratio by the daily average H₂S concentrations obtained using the monitor as required by paragraph (e)(3)(i) through (iii) of this section to estimate total sulfur concentrations.

(ix) If the total sulfur-to-H₂S ratio for a subsequent weekly sample is outside the 95 percent confidence interval for the most recent distribution of daily ratios, the owner or operator shall develop a new 10-day average ratio and 95 percent confidence interval based on data for the outlying weekly sample plus data collected over the following 9 operating days.

(f) *Flow monitoring for flares.* The owner or operator of an affected flare

subject to § 60.103a(a)(4) shall install, operate, calibrate, and maintain CPMS to measure and record the flare gas flow rate. The owner or operator of a modified flare shall install this instrument by no later than 18 months after the flare becomes an affected flare subject to this subpart unless the owner or operator of the affected flare commits in writing to install a flare gas recovery system, in which case flow monitoring is not required until after the flare has been an affected flare subject to this subpart for 2 years.

* * * * *

(g) * * *

(3) All rolling 365-day periods during which the average concentration of NO_x as measured by the NO_x continuous monitoring system required under paragraph (c) or (d) of this section exceeds:

(i) 40 ppmv or 0.035 lb/MMBtu for a newly constructed process heater or a modified or reconstructed natural draft process heater;

(ii) 60 ppmv or 0.055 lb/MMBtu for a modified or reconstructed forced draft process heater;

(iii) 150 ppmv or the daily average emission limit calculated using Equation 3 in § 60.102a(g)(2)(iv)(B) for a co-fired process heater; and

(iv) The site-specific limit determined by the Administrator under § 60.102a(i).

(4) All daily periods during which the concentration of NO_x as measured by the NO_x continuous monitoring system required under paragraph (d) of this section exceeds the applicable emissions limit in § 60.102a(g)(2)(iv).

12. Section 60.108a is amended by:

a. Revising paragraph (b);

b. Revising paragraph (c)(6)

introductory text and paragraphs

(c)(6)(ii) through (vi);

c. Adding paragraphs (c)(6)(vii), (viii) and (ix);

d. Adding paragraph (c)(7); and

e. Revising paragraph (d)(5) to read as follows:

§ 60.108a Recordkeeping and reporting requirements.

* * * * *

(b) Each owner or operator subject to an emissions limitation in § 60.102a or work practice standard in § 60.103a shall notify the Administrator of the specific monitoring provisions of §§ 60.105a, 60.106a, and 60.107a with which the owner or operator seeks to comply. The notification must include, if applicable, a written statement that the owner or operator of an affected flare is installing a flare gas recovery system or additional amine adsorption and stripping columns. Notification

shall be submitted with the notification of initial startup required by § 60.7(a)(3).

(c) * * *

(6) The owner or operator shall record and maintain records of discharges greater than 500 lb SO₂ in any 24-hour period from any affected flare, discharges greater than 500 lb SO₂ in excess of the allowable limits from a fuel gas combustion device other than a flare or sulfur recovery plant, and discharges to an affected flare in excess of 500,000 scf in any 24-hour period. The following information shall be recorded no later than 45 days following the end of a discharge exceeding the thresholds:

* * * * *

(ii) The date and time the discharge was first identified and the duration of the discharge.

(iii) The measured or calculated cumulative quantity of gas discharged over the discharge duration. If the discharge duration exceeds 24 hours, record the discharge quantity for each 24-hour period. For a flare, record the measured or calculated cumulative quantity of gas discharged to the flare over the discharge duration. If the discharge duration exceeds 24 hours, record the quantity of gas discharged to the flare for each 24-hour period. Engineering calculations are allowed for fuel gas combustion devices other than flares.

(iv) For each discharge greater than 500 lb SO₂ in any 24-hour period from a flare, the measured reduced sulfur concentration, measured total sulfur concentration, or both the measured H₂S concentration and the estimated total sulfur concentration in the fuel gas at a representative location in the flare inlet.

(v) For each discharge greater than 500 lb SO₂ in excess of the applicable short-term emissions limit in § 60.102a(g)(1) from a fuel gas combustion device other than a flare, either the measured concentration of H₂S in the fuel gas or the measured concentration of SO₂ in the stream discharged to the atmosphere. Process knowledge can be used to make these estimates for fuel gas combustion devices other than flares.

(vi) For each discharge greater than 500 lb SO₂ in excess of the allowable limits from a sulfur recovery plant, either the measured concentration of reduced sulfur or SO₂ discharged to the atmosphere.

(vii) For each discharge greater than 500 lb SO₂ in any 24-hour period from any affected flare or discharge greater than 500 lb SO₂ in excess of the allowable limits from a fuel gas

combustion device other than a flare or sulfur recovery plant, the cumulative quantity of H₂S and SO₂ released into the atmosphere. For releases controlled by flares, assume 99 percent conversion of reduced sulfur or total sulfur to SO₂. For other fuel gas combustion devices, assume 99 percent conversion of H₂S to SO₂.

(viii) The steps that the owner or operator took to limit the emissions during the discharge.

(ix) Results of any root cause analysis and corrective action analysis conducted as required in § 60.103a(a)(4) and (5) and § 60.103a(b), including a statement noting whether the discharge resulted from the same root cause identified in a previous analysis, and either a description of the corrective action and a schedule for implementation or an explanation of why corrective action is not necessary as required in § 60.103a(c).

(7) If the owner or operator complies with § 60.107a(d)(3) for a flare, records of the H₂S and total sulfur analyses of each grab or integrated sample, the calculated daily total sulfur-to-H₂S ratios, the calculated 10-day average total sulfur-to-H₂S ratios, and the 95

percent confidence intervals for each 10-day average total sulfur-to-H₂S ratio.

(d) * * *

(5) The information described in paragraph (c)(6) of this section for all discharges for which a root cause analysis, corrective action analysis, and implementation of corrective action were required by § 60.103a(a)(4) and (5), § 60.103a(b), and § 60.103a(c).

* * * * *

13. Section 60.109a is amended by revising paragraph (b) introductory text and adding paragraph (b)(4) to read as follows:

§ 60.109a Delegation of authority.

* * * * *

(b) In delegating implementation and enforcement authority of this subpart to a State, local, or tribal agency, the approval authorities contained in paragraphs (b)(1) through (4) of this section are retained by the Administrator of the U.S. EPA and are not transferred to the State, local, or tribal agency.

* * * * *

(4) Approval of a petition to establish a site-specific NO_x emissions limit for a

modified or reconstructed process heater under § 60.102a(i).

14. Table 1 to subpart Ja is added to read as follows:

Tables to Subpart Ja of Part 60

TABLE 1 TO SUBPART JA OF PART 60—MOLAR EXHAUST VOLUMES AND MOLAR HEAT CONTENT OF FUEL GAS CONSTITUENTS

Constituent	MEV ^a dscf/mol	MHC ^b Btu/mol
Methane (CH ₄) ..	7.28	842
Ethane (C ₂ H ₆) ...	12.94	1,475
Hydrogen (H ₂) ...	1.61	269
Ethene (C ₂ H ₄) ...	11.34	1,335
Propane (C ₃ H ₈) ...	18.61	2,100
Propene (C ₃ H ₆) ...	17.01	1,947
Butane (C ₄ H ₁₀) ...	24.28	2,717
Butene (C ₄ H ₈) ...	22.67	2,558
Inerts	0.85	0

^aMEV = molar exhaust volume, dry standard cubic feet per mole (dscf/mol).

^bMHC = molar heat content, Btu per mole (Btu/mol).

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