(b) *Regulated Area.* All waters on the Pamlico and Tar Rivers within a 300 yard radius of the launch site on land at position latitude 35°32′25″ N, longitude 077°03′42″ W. All geographic coordinates are North American Datum 1983 (NAD 83).

(c) *Regulations.* The general safety zone regulations contained in 33 CFR 165.23 of this part apply to the area described in paragraph (b) of this section.

(1) Persons or vessels requiring entry into or passage through any portion of the safety zone must first request authorization from the Captain of the Port, or a designated representative, unless the Captain of the Port previously announced via Marine Safety Radio Broadcast on VHF Marine Band Radio channel 22 (157.1 MHz) that this regulation will not be enforced in that portion of the safety zone. The Captain of the Port can be contacted at telephone number (910) 343–3882 or by radio on VHF Marine Band Radio, channels 13 and 16.

(d) *Enforcement.* The U.S. Coast Guard may be assisted in the patrol and enforcement of the zone by Federal, State, and local agencies.

(e) *Enforcement period.* This section will be enforced from 8 p.m. to 10 p.m. on September 22, 2012 unless cancelled earlier by the Captain of the Port.

Dated: July 30, 2012.

A. Popiel,

Captain, U.S. Coast Guard, Captain of the Port North Carolina.

[FR Doc. 2012–19841 Filed 8–13–12; 8:45 am]

BILLING CODE 9110–04–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[EPA–HQ–OAR–2010–0750; FRL–9667–3]

RIN 2060–AQ10

New Source Performance Standards Review for Nitric Acid Plants

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: The EPA is finalizing the new source performance standards (NSPS) for nitric acid plants. Nitric acid plants include one or more nitric acid production units (NAPUs). These revisions include a change to the nitrogen oxides (NO_X) emission limit, which applies to each NAPU commencing construction, modification, or reconstruction after October 14, 2011. These revisions also include additional testing and monitoring requirements.

DATES: This final rule is effective on August 14, 2012. The incorporation by reference of certain publications listed in this rule is approved by the Director of the Federal Register as of August 14, 2012.

ADDRESSES: *Docket:* The docket for this action is identified by Docket ID No. EPA–HQ–OAR–2010–0750. 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 form. Publicly available docket materials are available either electronically through *www.regulations.gov* or in hard copy at the EPA Docket Center, Public Reading Room, EPA West, 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 Air Docket is (202) 566–1742.

FOR FURTHER INFORMATION CONTACT: For questions about these standards for nitric acid plants, contact Mr. Nathan Topham, Sector Policies and Program Division, Office of Air Quality Planning and Standards (D243–02), Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone number (919) 541–0483; fax number (919) 541–3207, email address: *topham.nathan@epa.gov.*

SUPPLEMENTARY INFORMATION: The information presented in this preamble is organized as follows:

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VI. Summary of Cost, Environmental, Energy, and Economic Impacts of These Standards
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- C. Regulatory Flexibility Act as Amended by the Small Business Regulatory Enforcement Fairness Act (RFA) of 1996 (SBREFA), 5 U.S.C. 601 et seq.
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- F. Executive Order 13175: Consultation and Coordination with Indian Tribal Governments
- G. Executive Order 13045: Protection of Children from Environmental Health and Safety Risks
- H. Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use
- I. National Technology Transfer and Advancement Act
- J. Executive Order 12898: Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations
- K. Congressional Review Act

I. General Information

A. Does this action apply to me?

Categories and entities potentially regulated by these revisions include:

Category	NAICS code [1]	Examples of regulated entities
Industry	325311	Nitrogenous Fertilizer Manufacturing.
Federal government		Not affected.
State/local/tribal government		Not affected.

[1] North American Industrial 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 60.70a. If you have any questions regarding the applicability of this final action to a particular entity, contact the person in the preceding **FOR FURTHER INFORMATION CONTACT** section.

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

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

C. Judicial Review

Under CAA section 307(b)(1), judicial review of this final rule is available only by filing a petition for review in the U.S. Court of Appeals for the District of Columbia Circuit by October 15, 2012.

Under CAA section 307(d)(7)(B), only an objection to this final rule that was raised with reasonable specificity during the period for public comment (including any public hearing) can be raised during judicial review. This section also provides a mechanism for the EPA to convene a proceeding for reconsideration, ''[i]f the person raising an objection can demonstrate to the Administrator that it was impracticable to raise such objection within [the period for public comment] or if the grounds for such objection arose after the period for public comment (but within the time specified for judicial review) and if such objection is of central relevance to the outcome of the rule[.]'' Any person seeking to make such a demonstration to us should submit a Petition for Reconsideration to the Office of the Administrator, Environmental Protection Agency, Room 3000, Ariel Rios Building, 1200 Pennsylvania Ave. NW., Washington, DC 20004, with a copy to the person listed in the preceding **FOR FURTHER INFORMATION CONTACT** section, and the Associate General Counsel for the Air and Radiation Law Office, Office of General Counsel (Mail Code 2344A), Environmental Protection Agency, 1200 Pennsylvania Ave. NW., Washington, DC 20004. Note, under CAA section 307(b)(2), the requirements established by this final rule may not be challenged separately in any civil or criminal proceedings brought by EPA to enforce these requirements.

II. Background Information

A. What is the statutory authority for this final NSPS?

New source performance standards (NSPS) implement Clean Air Act (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. 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 nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated.

This level of control has sometimes been referred to as ''best demonstrated technology'' or BDT. In order to better reflect that, CAA section 111 was amended in 1990 to clarify that ''best systems'' may or may not be ''technology,'' the EPA is now using the term ''best system of emission reduction'' or BSER. In assessing whether a standard is achievable, EPA must account for routine operating variability associated with performance of the system on whose performance the standard is based. See *National Lime Ass'n* v. *EPA*, 627 F. 2d 416, 431–33 (DC Cir. 1980).

Common sources of information as to what constitutes a BSER, and for assessing that technology's level of performance, include test data collected during development of proposed rules, best available control technology (BACT) determinations made as part of new source review (NSR), emissions limits that exist in state and federal permits for recently permitted sources, and emissions test data for demonstrated control technologies collected for compliance demonstration or other purposes. EPA compares permit limitations and BACT determination data with actual performance test data to identify any site-specific factors that could influence general applicability of this information. Also, as part of this review we evaluate if NO_X emissions limits more stringent than those in Subpart G have been established, or if emissions limits have been developed for additional air pollutants.

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, when it is most cost effective to build in controls. Since 1970, the NSPS have been successful in achieving long-term emissions reductions in numerous industries by assuring that cost-effective controls are installed on new, reconstructed, or modified sources. Section 111(b)(1)(B) of the CAA requires EPA to periodically review and revise the standards of performance, as necessary, to reflect improvements in methods for reducing emissions.

Existing affected NAPUs that are modified or reconstructed would also be subject to these revisions for affected facilities. Under 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. Changes to an existing NAPU that do not result in an increase in emissions are not considered modifications.

Rebuilt affected NAPUs would become subject to the standards under the reconstruction provisions, regardless of changes in emission rate. Reconstruction means the replacement of components of an existing NAPU such that (1) the fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new NAPU; and (2) it is technologically and economically feasible to meet the applicable standards (40 CFR 60.15).

B. History of the NSPS for Nitric Acid Plants

The NSPS for Nitric Acid Plants (40 CFR part 60, Subpart G) were promulgated in the **Federal Register** on December 23, 1971 (36 FR 24881). The first review of the Nitric Acid Plants NSPS was completed on June 19, 1979 (44 FR 35265). An additional review was completed on April 5, 1984 (49 FR 13654). No changes were made to the NSPS as a result of those reviews. Minor testing and monitoring changes were made during three reviews since the original promulgation in 1971 (October 6, 1975 (40 FR 46258), April 22, 1985 (50 FR 15894), and February 14, 1989 (54 FR 6666)). Subpart G applies to each NAPU constructed or modified after

August 17, 1971, and on or before October 14, 2011. Subpart G has an emissions limit of 3.0 lb of NO_X per ton of 100 percent nitric acid produced (based on any 3-hour average) and a 10 percent opacity standard as an additional method of demonstrating compliance with the NO_X emission limit. Continuous NO_X monitors are required as well as recording daily production rates.

III. Summary of the Final NSPS

A. What source category is being regulated?

Today's standards (Subpart Ga) apply to new NAPUs. The affected facility under the final NSPS is each NAPU. Nitric acid plants may include one or more NAPUs. A new NAPU is defined as a NAPU for which construction, modification, or reconstruction commences after October 14, 2011.

For purposes of these final regulations, a NAPU is defined as any facility producing weak nitric acid by either the pressure or atmospheric pressure process. This definition has not changed from Subpart G.

B. What pollutants are emitted from these sources?

The pollutant to be regulated under section 111(b) in today's action, for new NAPUs, is NO_X, which undergoes reactions in the atmosphere to form particulate matter and ozone. Nitrogen oxides, particulate matter, and ozone are all criteria pollutants that are subject to national ambient air quality standards under section 109 of the Clean Air Act, based on their adverse effects to human health and welfare.

These NAPUs also emit another nitrogen compound known as nitrous oxide (N_2O), which is considered a greenhouse gas (GHG). We are not taking final agency action with respect to a GHG emission standard in this action. The EPA is in the process of gathering and analyzing additional data on GHG emissions from NAPUs that will allow the Agency to continue working towards a proposal for GHG standards for nitric acid plants.

C. What are the final requirements for new nitric acid production units?

As proposed, and after consideration of the comments we received, we are reducing the NO_X emissions limit from 3.0 pounds of NO_X (expressed as NO_2) per ton of 100 percent nitric acid produced (lb NO_X/ton acid) to 0.50 lb NO_X/ton acid as a 30 operating day emission rate calculated each operating day based on the previous 30 operating days.

The general provisions in 40 CFR part 60 provide that emissions in excess of the level of the applicable emissions limit during periods of startup, shutdown, and malfunction shall not be considered a violation of the applicable emission limit unless otherwise specified in the applicable standard. See 40 CFR 60.8(c). The general provisions, however, may be amended for individual subparts. See 40 CFR 60.8(h). In today's action, the EPA is finalizing standards in Subpart Ga that apply at all times, including periods of startup or shutdown, and periods of malfunction.

Periods of Startup or Shutdown. Consistent with *Sierra Club* v. *EPA* (551 F.3d 1019 (DC Cir. 2008)), the EPA has established standards in this rule that apply at all times. In revising the standards in this rule, the EPA has taken into account startup and shutdown periods and, for the reasons explained below, has not established different standards for those periods.

According to information received from industry in the section 114 ICR, NO_X emissions during startup and shutdown are higher than during normal operations for some nitric acid plants. However, due to the relatively short duration of startup and shutdown events (generally a few hours per month) compared to normal steady-state operations, we conclude that a 30-day emission rate calculated based on 30 operating days will allow affected facilities to meet the 0.50 lb NO_X/ton acid at all times, including periods of startup and shutdown.

If higher NO_X emissions during periods of startup and shutdown are a concern, there are two types of equipment that can be used by affected facilities. These include startup heaters and hydrogen peroxide injection. Startup heaters are used to heat the SCR so that it can begin to reduce NO_X during startups. Hydrogen peroxide injection, which is not applicable in all situations, can also be used to decrease NO_X emissions in the extended absorption column.

Periods of Malfunction. As explained in the preamble to the proposed rule, periods of startup, normal operations, and shutdown are all predictable and routine aspects of a source's operations. However, by contrast, malfunction is defined as a "sudden, infrequent, and not reasonably preventable failure of air pollution control equipment, process equipment or a process to operate in a normal or usual manner * * *" (40 CFR 60.2). As explained in more detail in the proposed rule, EPA has determined that CAA section 111 does not require that emissions that occur during periods of malfunction be factored into development of CAA section 111 standards.

Further, accounting for malfunctions would be difficult, if not impossible, given the myriad different types of malfunctions that can occur across all sources in the category and given the difficulties associated with predicting or accounting for the frequency, degree, and duration of various malfunctions that might occur. As such, the performance of units that are malfunctioning is not "reasonably" foreseeable. See, e.g., *Sierra Club* v. *EPA,* 167 F. 3d 658, 662 (DC Cir. 1999) ("[T]he EPA typically has wide latitude in determining the extent of data-gathering necessary to solve a problem. We generally defer to an agency's decision to proceed on the basis of imperfect scientific information, rather than to 'invest the resources to conduct the perfect study.' "). See also, *Weyerhaeuser* v. *Costle,* 590 F.2d 1011, 1058 (DC Cir. 1978) ("In the nature of things, no general limit, individual permit, or even any upset provision can anticipate all upset situations. After a certain point, the transgression of regulatory limits caused by 'uncontrollable acts of third parties,' such as strikes, sabotage, operator intoxication or insanity, and a variety of other eventualities, must be a matter for the administrative exercise of case-by-case enforcement discretion, not for specification in advance by regulation."). In addition, accounting for malfunctions when setting standards of performance under section 111 which reflect the degree of emission limitation achievable through "the application of the best system of emission reduction" that the EPA determines is adequately demonstrated could lead to standards that are significantly less stringent than levels that are achieved by a well-performing non-malfunctioning source. The EPA's approach to malfunctions is consistent with section 111 and is a reasonable interpretation of the statute.

In the event that a source fails to comply with the applicable CAA section 111 standards as a result of a malfunction event, the EPA would determine an appropriate response based on, among other things, the good faith efforts of the source to minimize emissions during malfunction periods, including preventative and corrective actions, as well as root cause analyses to ascertain and rectify violations. The EPA would also consider whether the source's failure to comply with the CAA section 111 standard was, in fact, "sudden, infrequent, not reasonably preventable" and was not instead "caused in part by poor maintenance or

careless operation.'' 40 CFR 60.2 (definition of malfunction).

Finally, the EPA recognizes that even equipment that is properly designed and maintained can sometimes fail and that such failure can sometimes cause a violation of the relevant emission standard. The EPA is therefore finalizing an affirmative defense to civil penalties for violations of emission standards that are caused by malfunctions. See 40 CFR 60.71a (defining ''affirmative defense'' to mean, in the context of an enforcement proceeding, a response or defense put forward by a defendant, regarding which the defendant has the burden of proof, and the merits of which are independently and objectively evaluated in a judicial or administrative proceeding.). We also have finalized other regulatory provisions to specify the elements that are necessary to establish this affirmative defense; the source must prove by a preponderance of the evidence that it has met all of the elements set forth in 60.74a. (See 40 CFR 22.24). The criteria ensure that the affirmative defense is available only where the event that causes a violation of the emission standard meets the narrow definition of malfunction in 40 CFR 60.2 (sudden, infrequent, not reasonable preventable and not caused by poor maintenance and or careless operation). For example, to successfully assert the affirmative defense, the source must prove by a preponderance of the evidence that the violation ''[w]as caused by a sudden, infrequent, and unavoidable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner * * *.'' The criteria also are designed to ensure that steps are taken to correct the malfunction, to minimize emissions in accordance with section 60.72a(b) and to prevent future malfunctions. For example, the source must prove by a preponderance of the evidence that ''[r]epairs were made as expeditiously as possible when a violation occurred * * *'' and that ''[a]ll possible steps were taken to minimize the impact of the violation on ambient air quality, the environment and human health * * *.'' In any judicial or administrative proceeding, the Administrator may challenge the assertion of the affirmative defense and, if the respondent has not met its burden of proving all of the requirements in the affirmative defense, appropriate penalties may be assessed in accordance with Section 113 of the Clean Air Act (see also 40 CFR 22.27).

The EPA proposed and is now finalizing an affirmative defense in this rule in an attempt to balance a tension, inherent in many types of air regulations, to ensure adequate compliance while simultaneously recognizing that despite the most diligent of efforts, emission standards may be violated under circumstances beyond the control of the source. The EPA must establish emission standards that ''limit the quantity, rate, or concentration of emissions of air pollutants on a continuous basis.'' 42 U.S.C. § 7602(k) (defining ''emission limitation and emission standard''). See generally *Sierra Club* v. *EPA,* 551 F.3d 1019, 1021 (D.C. Cir. 2008). Thus, the EPA is required to ensure that Section 111 emissions standards are continuous. The affirmative defense for malfunction events meets this requirement by ensuring that even where there is a malfunction, the emission standard is still enforceable through injunctive relief. While ''continuous'' standards, on the one hand, are required, there is also caselaw indicating that in many situations it is appropriate for the EPA to account for the practical realities of technology. For example, in *Essex Chemical* v. *Ruckelshaus,* 486 F.2d 427, 433 (D.C. Cir. 1973), the D.C. Circuit acknowledged that in setting standards under CAA section 111 ''variant provisions'' such as provisions allowing for upsets during startup, shutdown and equipment malfunction ''appear necessary to preserve the reasonableness of the standards as a whole and that the record does not support the 'never to be exceeded' standard currently in force.'' See also, *Portland Cement Association* v. *Ruckelshaus,* 486 F.2d 375 (D.C. Cir. 1973). Though intervening caselaw such as *Sierra Club* v. *EPA* and the CAA 1977 amendments calls into question the relevance of these cases today, they support the EPA's view that a system that incorporates some level of flexibility is reasonable. The affirmative defense simply provides for a defense to civil penalties for violations that are proven to be beyond the control of the source. By incorporating an affirmative defense, the EPA has formalized its approach to upset events. In a Clean Water Act setting, the Ninth Circuit required this type of formalized approach when regulating ''upsets beyond the control of the permit holder.'' *Marathon Oil Co.* v. *EPA,* 564 F.2d 1253, 1272–73 (9th Cir. 1977). See also, *Mont. Sulphur & Chem. Co.* v. *United States EPA,* 2012 U.S. App. LEXIS 1056 (Jan 19, 2012) (rejecting industry argument that reliance on the affirmative defense was not adequate). But see, *Weyerhaeuser Co.* v. *Costle,* 590 F.2d 1011, 1057–58 (D.C. Cir. 1978) (holding that an informal approach is adequate). The affirmative defense provisions give the EPA the flexibility to both ensure that its emission standards are ''continuous'' as required by 42 U.S.C. 7602(k), and account for unplanned upsets and thus support the reasonableness of the standard as a whole.

IV. Summary of Significant Changes Since Proposal

A. How is the EPA revising the proposed emissions limit for affected facilities?

For affected facilities constructed, modified, or reconstructed after October 14, 2011, we proposed to reduce the NO_X emissions limit from 3.0 lb NO_X/ton acid to 0.50 lb NO_X/ton acid as a 30-day emission rate calculated each operating day based on the previous 30 consecutive operating days. See 76 FR 63878 (October 14, 2011). For these final standards, we are promulgating the proposed NO_X emissions limit of 0.50 lb NO_X/ton acid as a 30 operating day emission rate calculated each operating day based on the previous 30 operating days. In response to commenters' concerns related to how the 30 day emission rate is calculated, we have revised the equation used to calculate the 30 day emission rate. This revision prevents days with very few operating hours from having an artificially large influence on the calculated 30 day emission rate. See Section V of this preamble, *Statistical Evaluation of CEMS Data to Determine the NO_X Emission Standard (Updated Memo for Final Standard),* and the *Response to Comment Document* for more information on calculation of the 30 day emission rates. The two documents mentioned above are available in the docket for this final rule.

The conclusion that selective catalytic reduction (SCR) is BSER has not changed from proposal. The justification includes the following reasons: (1) Based on the data available to the Agency, SCR achieves lower emissions than other control technologies; (2) SCR technology is less expensive and more cost effective than nonselective catalytic reduction (NSCR) for control of NO_X emissions; and (3) SCR produces minimal secondary environmental impacts. In addition, we note that SCR is the only known NO_X control technology being installed in new NAPUs and SCR has been determined to be BACT in several recent BACT determinations.

Although the limit of 0.50 lb NO_X/ton acid is based on the data for SCR, NSPS do not require the use and installation of a specific control device. Whether NSCR can meet the levels achievable by

SCR over a long term was an area of uncertainty at proposal. At proposal, the long term CEMS data from 2 NSCR plants (PCS Geismar Train 4 and Agrium Sacramento) indicated that neither plant was achieving the 0.50 lb NO_X/ton limit. After proposal, we evaluated continuous NO_X emission data from Dyno Nobel—St Helens (which uses NSCR) that showed a maximum 30 day emission rate of 0.21 lb NO_X/ton acid. Also, we had monthly data from JR Simplot (another nitric acid plant with NSCR) that ranged from 0.15 to 0.36 lb NO_X/ton acid. Although the data from JR Simplot are not directly comparable to continuous NO_X emission data (hour by hour), there is a strong probability that this source also could comply with 0.50 lb NO_X/ton acid. Therefore, we conclude the standard of 0.50 lb NO_X/ton acid limit is achievable for at least some NAPUs using NSCR.

We conclude that new NAPUs will be able to meet the limit taking into consideration routine operating variability as well as variation due to weather and periods of startup and shutdown as the data analyzed included all of these periods. Based on the data available to the agency, the limit is demonstrated in practice and achievable for new, modified, or reconstructed sources. See *Statistical Evaluation of CEMS Data to Determine the NO_X Emission Standard (Updated Memo for Final Standard),* for more information.

B. How is the EPA revising the testing and monitoring requirements that were proposed for Subpart Ga of Part 60?

We are finalizing the testing and monitoring requirements that were proposed for Subpart Ga and adding the requirement of a dual span monitor for reasons explained in Section V of this preamble.

C. How is the EPA revising the notification, reporting, and recordkeeping requirements that were proposed for Subpart Ga?

The reporting and recordkeeping requirements that we proposed are being finalized as separate sections for Subpart Ga. Since proposal, there have been minor changes to the reporting language at § 60.77a(e) in relation to EPA's Central Data Exchange (CDX), detailed below, but no other changes have been made to the electronic reporting requirements.

The EPA must have performance test data to conduct effective reviews of CAA section 111 standards, as well as for many other purposes including compliance determinations, emission factor development, and annual emission rate determinations. In conducting these required reviews, the EPA has found it ineffective and time consuming, not only for us, but also for regulatory agencies and source owners and operators, to locate, collect, and submit performance test data because of varied locations for data storage and varied data storage methods. In recent years, though, stack testing firms have typically collected performance test data in electronic format, making it possible to move to an electronic data submittal system that would increase the ease and efficiency of data submittal and improve data accessibility.

In this action, as a step to increase the ease and efficiency of data submittal and improve data accessibility, EPA is requiring the electronic submittal of select performance test data. Specifically, the EPA is requiring owners and operators of Nitric Acid facilities to submit electronic copies of performance test reports required under Subpart Ga of part 60 to the EPA's WebFIRE database. The WebFIRE database was constructed to store performance test data for use in developing emission factors. A description of the WebFIRE database is available at *http://cfpub.epa.gov/oarweb/index.cfm?action=fire.main.*

As mentioned above, data entry will be through an electronic emissions test report structure called the Electronic Reporting Tool (ERT). The ERT will generate an electronic report which will be submitted using the Compliance and Emissions Data Reporting Interface (CEDRI). The submitted report is submitted through the EPA's Central Data Exchange (CDX) network for storage in the WebFIRE database making submittal of data very straightforward and easy. A description of the ERT can be found at *http://www.epa.gov/ttn/chief/ert/index.html* and CEDRI can be accessed through the CDX Web site (*www.epa.gov/cdx*).

The requirement to submit performance test data electronically to the EPA does not create any additional performance testing and would apply only to those performance tests conducted using test methods that are supported by the ERT. The ERT contains a specific electronic data entry form for most of the commonly used EPA reference methods. A listing of the pollutants and test methods supported by the ERT is available at *http://www.epa.gov/ttn/chief/ert/index.html.* We believe that industry will benefit from this new electronic data submittal requirement. Having these data, the EPA will be able to develop improved emission factors, make fewer information requests, and promulgate better regulations. The information to be reported is already required for the existing test methods and is necessary to evaluate the conformance to the test method.

One major advantage of submitting performance test data through the ERT is a standardized method to compile and store much of the documentation required to be reported by this rule. Another advantage is that the ERT clearly states what testing information would be required. Another important benefit of submitting these data to the EPA at the time the source test is conducted is that it should substantially reduce the effort involved in data collection activities in the future. When the EPA has performance test data in hand, there will likely be fewer or less substantial data collection requests in conjunction with prospective technology reviews. This results in a reduced burden on both affected facilities (in terms of reduced manpower to respond to data collection requests) and the EPA (in terms of preparing and distributing data collection requests and assessing the results).

State, local, and tribal agencies can also benefit from a more streamlined and accurate review of electronic data submitted to them. The ERT allows for an electronic review process rather than a manual data assessment making review and evaluation of the data and calculations easier and more efficient. Finally, another benefit of submitting data to WebFIRE electronically is that these data will greatly improve the overall quality of the existing and new emission factors by supplementing the pool of emissions test data for establishing emissions factors and by ensuring that the factors are more representative of current industry operational procedures. A common complaint heard from industry and regulators is that emission factors are outdated or not representative of a particular source category. With timely receipt and incorporation of data from most performance tests, the EPA will be able to ensure that emission factors, when updated, represent the most current range of operational practices. In summary, in addition to supporting regulation development, control strategy development, and other air pollution control activities, having an electronic database populated with performance test data will save industry, state, local, tribal agencies, and the EPA significant time, money, and effort while improving the quality of emission inventories and, as a result, air quality regulations.

Several changes were made to the recordkeeping and reporting provisions related to the affirmative defense

provisions of the final rule. In addition to minor wording changes to improve clarity, the EPA added language to 60.74a(a)(9) to clarify that the purpose of the root cause analysis is to determine, correct, and eliminate the primary cause of the malfunction. The root cause analysis itself does not necessarily require that the cause be determined, corrected or eliminated. However, in most cases, the EPA believes that a properly conducted root cause analysis will have such results. The EPA also eliminated the 2-day notification requirement in 60.74a because EPA will receive sufficient notification of malfunction events that result in violations in other required compliance reports, such as the reports required under 60.77a. In addition, EPA revised 60.74a(b) to state that "[t]he owner or operator seeking to assert an affirmative defense shall submit a written report to the Administrator with all necessary supporting documentation, that it has met the requirements set forth in paragraph (a) of this section. This affirmative defense report shall be included in the first periodic compliance, deviation report or excess emission report otherwise required after the initial occurrence of the violation of the relevant standard (which may be the end of any applicable averaging period). If such compliance, deviation report or excess emission report is due less than 45 days after the initial occurrence of the violation, the affirmative defense report may be included in the second compliance, deviation report or excess emission report due after the initial occurrence of the violation of the relevant standard."

V. Summary of Significant Comments and Responses to the Proposed NSPS

The EPA received comments on a number of issues during the public comment period. These issues include the level and time period of the NO_X standard, NO_X monitoring requirements, issues related to startup and shutdown, and regulation of GHGs from nitric acid plants. Summaries of the major comments and EPA responses are presented in the following paragraphs. Summaries of comments on these and other issues that are not presented in the preamble, as well as the EPA's responses to those comments, can be found in the *Response to Comment Document.* The *Response to Comment Document* is available in the docket for this final rule, EPA–HQ–OAR–2010–0750.

Comment: Multiple commenters supported the EPA's decision to tighten the standard for NO_X emissions. One commenter stated that the revisions to the standard are warranted given the low emissions achieved by well controlled facilities across the industry, as shown in the ICR data, and the lengthy delay in reviewing the NSPS. The commenter asks that the EPA consider the myriad health effects related to NO_X emissions when determining the standard for the final rule. The commenter notes that these effects include direct effects from NO_X exposure as well as effects of secondary pollutants, such as ozone and fine particulate matter, for which NO_X is a precursor.

One commenter agrees that the EPA has clearly demonstrated that its proposed NO_X standard of 0.50 lb/ton based on a 30-day rolling emission rate is not only "achievable" and "adequately demonstrated," it is already routinely being achieved at multiple facilities within the industry. Given the technology-forcing nature of Section 111's BDT standard, the commenter believes that EPA could establish a standard more stringent than its current proposal. Nevertheless, the commenter believes that the proposed emission limit is within the range of what is reasonable for purposes of the NSPS program.

Another commenter stated that the standard should be more stringent than what was proposed based on the fact that some facilities are achieving lower emissions than the proposed limit. The commenter further stated that the EPA failed to justify why a standard more stringent than 0.50 lb/ton was not proposed. The commenter states that the EPA appeared to accommodate current industry practice rather than comply with the "technology forcing" mandate of CAA section 111. One commenter suggested that the EPA should set a tighter limit than the proposed standard because "most control systems installed on future affected facilities would achieve emissions below the proposed emissions limit even in the absence of these proposed revisions."

Response: The EPA disagrees with commenters that the emission limit should be more stringent. The EPA believes that the rationale for proposing the standard of 0.50 lb NO_X/ton acid was well supported by the emissions data and continues to be well supported for the final rule. The emissions data from the three ICR test plants that employ SCR (Agrium North Bend, PCS Geismar Train 5, and El Dorado Nitrogen) have no discernible differences in technology or process that would account for the differences in emission levels. Therefore we selected an emission limit that was achievable by all three of the units controlled by SCR.

Emissions during some short periods (e.g. startup and shutdown) can be higher than during steady state operations at some nitric acid plants. At proposal, we estimated these periods to occur on average about 3 to 4 hours per month. However, as the result of public comments, we have learned that these periods can occur more frequently for some facilities. These periods still make up an extremely small fraction of total operating time (i.e. about 1 percent or less). In response to public comments, the final rule contains a revised method for calculating NO_X emissions. The calculation method used at proposal assumed that each operating day was weighted equally, regardless of the numbers of operating hours during that day. The proposed method could hypothetically lead to a day with only a few operating hours contributing 1/30th of the calculated rolling emission rate. The calculation method used for the final rule has been established such that every hourly NO_X concentration monitored during each 30 unit operating day period is weighted equally. The adjusted calculation calculates each hourly emission rate and divides by the total operating hours. This adjustment prevents infrequent and short duration events from having an unrepresentatively large impact on the 30 day rolling emission rate. Using the adjusted calculation method, the maximum 30 day rolling emission rate for any of the three ICR test plants with SCR is 0.41 lb NO_X/ton acid at Agrium North Bend.

The EPA also reanalyzed the CEMS data using the assumption that the number of periods of startup and shutdown could be higher for some facilities compared to the number of periods reported for Agrium North Bend. EPA compared the number of startup/shutdown periods for Agrium North Bend to the highest number of startup/shutdown periods reported through the Section 114 request.

According to the information received in response to the Section 114 request, the highest number of hourly startup/shutdown (SS) periods per year was reported as 95 by Coffeyville. Information received after publication of the proposed rule indicates there are reasons that other facilities may startup and shutdown more frequently than the Agrium North Bend facility.

To look at the impact of more frequent start up and shutdown periods, we doubled the 67 hourly SS periods reported by Agrium North Bend to 134 hourly SS periods, which would place them above the highest number of SS periods from any of our Section 114 respondents. Then, we analyzed the

CEMS data for Agrium North Bend by assuming that the number of SS periods is doubled. The resulting maximum 30 operating day emission rate is 0.47 lb NO_X/ton acid. This example demonstrates that the limit promulgated in this final rule is achievable by affected facilities that experience more periods of startup and shutdown than the Agrium North Bend plant. See *Agrium North Bend Analyses,* and *Statistical Evaluation of CEMS Data to Determine the NO_X Emission Standard (Updated Memo for Final Standard),* available in docket ID: EPA–HQ–OAR–2010–0750. Thus, we conclude that a limit of 0.50 lb NO_X/ton acid is appropriate.

The EPA disagrees with the commenter that stated ''the proposed standard appears to simply accommodate current industry practice rather than properly comply with the EPA's technology-forcing mandate under CAA § 111.'' The EPA maintains that SCR is the ''best system of emission reduction'' even though it is not a new technology. It is unclear what technologies the commenter suggests would work more effectively for controlling NO_X emissions than those evaluated during this rulemaking (SCR and NSCR). Though the CAA is intended to be ''technology-forcing,'' NSPS must be set based on ''substantial evidence that such improvements are feasible and will produce the improved performance necessary to meet the standard.'' *Sierra Club* v. *Costle,* 657 F.2d 298, 364 (D.C. Cir. 1981). As one court stated, ''[t]he statutory standard is one of achievability, given costs.'' *National Lime Assn.* v. *EPA,* 627 F.2d 416, 431 n.46 (D.C. Cir. 1980). Further, in assessing whether a standard is achievable, the EPA must account for routine operating variability associated with performance of the system on whose performance the standard is based. See *National Lime Ass'n,* 627 F. 2d at 431–33. While NSPS are based on the effectiveness of one or more specific technological systems of emissions control, unless certain conditions are met, the CAA does not authorize the EPA to prescribe a particular technological system that must be used to comply with a NSPS. See CAA section 111(b)(5). Rather, sources can select whatever combination of measures will achieve equivalent or greater control of emissions.

Comment: Commenters stated that the EPA did not fulfill the requirements of CAA section 111 because the agency failed to consider the variable conditions present in the industry that impact that achievability of the proposed standard. Specifically, the commenters stated that the EPA failed to consider the costs of adding additional controls to modified or reconstructed facilities that are controlled with NSCR given that the EPA acknowledged that there was uncertainty at the time of the proposed rule that NSCR controlled plants could achieve the 0.50 lb/ton limit.

Another commenter stated that the facilities used to develop the proposed standard are not representative of the industry as a whole because these three facilities use controls that are not in use or not available to all nitric acid plants. The commenter notes that two of the three plants (PCS Geismar and El Dorado Nitrogen) were designed with dual-pressure technology and other features that minimize emissions. According to the commenter, these technologies may not be available to smaller new plants or modified plants. The commenter also notes that El Dorado Nitrogen has high pressure steam that can be used to pre-heat the SCR and the Agrium North Bend facility uses hydrogen peroxide injection and extended absorption. According to the commenter, these control technologies may not be economically feasible for some facilities. The commenter further states that adding a SCR or NSCR may not be enough to meet the proposed limit for some existing mono-pressure facilities that trigger the NSPS.

Response: The EPA agrees that further evaluation of the achievability of the standard by nitric acid plants that have been modified or reconstructed was warranted prior to issuing the final rule. The commenters identified a few nitric acid plants that fit those definitions, and we performed further evaluation of the NO_X CEMS data for such plants.

A BACT determination has been made on a modified source (Agrium North Bend) for which we have CEMS data. We note that the Agrium North Bend facility is a relatively small, monopressure, modified facility. As part of our evaluation, we analyzed the data for this plant to estimate emissions performance of this BACT facility and have determined this facility meets the NO_X limit in this final rule. See memo entitled *Agrium North Bend Analyses,* which is available in the docket for this rulemaking: EPA–HQ–OAR–2010–0750.

As a part of our analysis, we have evaluated the cost for controls required for the Agrium North Bend plant when this facility was modified. An SCR was installed at a capital cost of roughly $2,700,000 ($370,000 annualized cost, assuming a 20 year capital recovery period). This facility achieved emissions reductions of nearly 300 tons of NO_X per year. From these figures, we calculate the cost effectiveness for the addition of this control device as roughly $1,200 per ton of NO_X. See the memo *Impacts of Nitric acid NSPS Review-NO_X (Updated Memo for Final NSPS).* We conclude this cost effectiveness is reasonable and supported by NSPS for NO_X for other source categories. See 77 FR 9303, 76 FR 24976, 75 FR 51570, and 75 FR 55009.

The EPA has decided to promulgate a limit of 0.50 lb NO_X/ton calculated in a manner that is more appropriate than what was proposed. The calculation in the final rule uses each hourly NO_X emission rate during the 30 day period rather than creating 30 daily values. See *Statistical Evaluation of CEMS Data to Determine the NO_X Emission Standard (Updated Memo for Final Standard),* and *Agrium North Bend Analyses,* for more information on the 30 day rolling emission rate calculations. We conclude that the modified monopressure Agrium North Bend plant would meet this emission limit of 0.50 lb NO_X/ton acid, and that this level is appropriate for future modified and reconstructed sources as well as new sources. For a discussion of the data received from the American Chemistry Council after the proposed rule, see *Analysis of Data Received Between Proposal and Promulgation of Part 60, Subpart Ga,* which is available in docket ID EPA–HQ–OAR–2010–0750. Also see *Response to Comment Document* section 7.1–7.3.

At proposal, there was uncertainty as to whether units using NSCR could achieve the proposed limits. We have evaluated CEMS data for two additional plants using NSCR and these facilities do meet the final emission limit. We evaluated continuous NO_X emission data from Dyno Nobel St. Helens. This analysis shows a maximum 30 operating day emission rate of 0.21 lb NO_X/ton acid. Also, we had monthly data from JR Simplot, a nitric acid plant controlled by NSCR, which ranged from 0.15 lb NO_X/ton acid to 0.36 lb NO_X/ton acid. Although monthly data are not directly comparable to continuous hourly NO_X emission data, there is a strong probability that this source controlled by NSCR could comply with 0.50 lb NO_X/ton acid. Therefore, based on our evaluation of this technical information, we conclude the standard of 0.50 lb NO_X/ton acid limit is achievable for at least some nitric acid production units using NSCR.

The conclusion that selective catalytic reduction (SCR) is BSER has not changed from proposal. The justification includes the following reasons: (1) Based on the data available to the Agency, SCR achieves lower emissions

than other control technologies; (2) SCR technology is less expensive and more cost effective than nonselective catalytic reduction (NSCR) for control of NO_X emissions; and (3) SCR produces minimal secondary environmental impacts. In addition, we note that SCR is the only known NO_X control technology being installed in new NAPUs and SCR has been determined to be BACT in several recent BACT determinations.

If higher NO_X emissions during periods of startup and shutdown are a concern, there are two types of equipment that can be used by affected facilities. These include startup heaters and hydrogen peroxide injection. Startup heaters are used to heat the SCR to the appropriate operating temperature so that the SCR can be operational during startups, thereby reducing NO_X emissions during startup. Hydrogen peroxide injection, which is not applicable in all situations, can also be used in the extended absorption column to decrease NO_X emissions. Affected facilities could also employ extended absorption to increase the yield of nitric acid; thus reducing the amount of NO_X emitted from the absorption unit. We recognize that there may be circumstances where one or more of these specific types of equipment or measures may not be feasible. However, based on all of the data and information that we have gathered and analyzed, we conclude any facility (including mono pressure units) that chooses to modify or reconstruct will be able to achieve a limit of 0.50 lb/ton at a reasonable costs by adding controls (e.g., SCR) and or by making other changes such as those described above. Additionally, because the standard is based on 30-day emission rates, even if these technologies are not employed, emissions during brief periods of startup or shutdown should not have substantial impacts on the source's ability to meet the standard.

Comment: Several commenters supported the EPA's decision not to take final agency action with respect to greenhouse gases in today's rule. The commenters stated that the EPA is not obligated to develop standards for GHG as a part of the 8 year review of the NSPS and that the EPA has broad discretion to decide whether and how to regulate greenhouse gases.

Alternatively, some commenters state that the EPA's discretion to develop standards for pollutants not previously subject to NSPS is limited by the language of the statute. The commenters state that the clearest reading of CAA sections 111(a) and 111(b) require the EPA to regulate any pollutant emitted from a listed source category when it is cost effective to do so.

Multiple commenters assert that Congress intended for the EPA to regulate the full scope of air pollution emitted by a source category when developing the initial NSPS because the language of CAA section 111 repeatedly refers to "any" air pollutant emitted by source categories subject to regulation under this section. The commenter asserts that the use of the word "any" as a modifier for "air pollutant" limits the EPA's discretion to decline to set NSPS for pollutants emitted from a listed source category. Although "any" is not included as a modifier for "air pollutant" in Section 111(a)(1)'s definition of "standard of performance," the commenter notes that it is included in the definitions of the term "modification." According to the commenter, under Section 111(b), NSPS standards apply to facilities constructed or modified after standards have been set. The commenter notes that if an existing facility undergoes a modification, a physical change that increases the emission of "any" air pollutant, it is a structure now subject to NSPS. The commenter asserts that reading Section 111 to allow for unlimited agency discretion on which pollutants require performance standards could lead to the peculiarity that a facility could become subject to NSPS regulation by increasing its emissions of a pollutant for which EPA has chosen not to set standards. According to one commenter, the emissions of GHGs from nitric acid plants would warrant listing the nitric acid plant source category, even in the absence of NO_X emissions. The commenter asserts that the EPA is obligated to set standards for GHGs from nitric acid plants to avoid a situation in which a facility could become subject to NSPS for increased emissions of a pollutant that is not subject to a standard. The commenters say that the same scope that applies when the EPA develops new NSPS exists when the EPA reviews an existing NSPS and requires the EPA to review and update (or develop) the performance standard for all emitted air pollutants.

One commenter states that the EPA must regulate GHGs in this rulemaking action based on the decision by the U.S. Supreme Court in *Massachusetts* v. *EPA,* which held that GHGs fall within the CAA definition of "air pollutant". The commenter states that since GHGs are defined as "air pollutants" and Section 111 of the CAA creates a general duty for the EPA to regulate such emissions, it would be unlawful for the EPA to choose not to regulate GHGs in this action. The commenter states that the EPA has failed to provide an adequate explanation for its failure to regulate nitrous oxide and other greenhouse gas emissions from nitric acid plants. According to the commenter, the only way the EPA could legitimately avoid establishing standards for nitrous oxide and other greenhouse gas emissions from nitric acid plants would be if it developed a record clearly demonstrating that such regulations would not be appropriate based on relevant and lawful considerations. The commenter notes that the EPA has made no effort to make such a showing with respect to nitric acid plants.

Response: While the CAA permits the EPA, under appropriate circumstances, to add new standards of performance for additional pollutants, the EPA is not taking final agency action with regard to standards for GHG at this time.

The EPA has promulgated new performance standards for pollutants not previously covered concurrent with some previous 8-year review rulemakings. See 52 FR 24672, 24710 (July 1, 1987) (considering PM_{10} controls in future rulemakings); 71 FR 9866 (February 27, 2006) (new PM standards for boilers). Additionally, as commenters correctly point out, the EPA is promulgating a new standard of performance for NO_X emissions from certain affected facilities at nitric acid plants in this rulemaking. The EPA does not yet have adequate information regarding emissions of GHGs from nitric acid plants, the cost and secondary impacts of controlling NO_X and GHGs, and the level of emissions achieved through simultaneous control of GHGs and NO_X. However, because the Agency is in the process of gathering information and reviewing controls for this industry to continue working towards a proposal for GHG standards for nitric acid plants, the EPA is not taking any final action in today's rule with respect to a GHG standard for nitric acid plants.

Comment: Multiple commenters state that the EPA must promulgate section 111(d) standards for existing facilities within the nitric acid sector. One commenter states that promulgation of a performance standard for greenhouse gas emissions from newer nitric acid plants will enable (and compel) EPA to issue emission guidelines and to require states to submit implementation plans demonstrating how they will control greenhouse gas emissions from existing nitric acid plants. The commenter notes that Section 111(d) was meant to be a gap-filling provision intended to regulate this third category, and EPA's

main focus was on pollutants rather than source categories. Here, according to the commenter, nitrous oxide and other greenhouse gases are pollutants that endanger public health welfare, and existing nitric acid plants are significant sources of such pollution. According to the commenter, existing nitric acid plants account for the vast majority of the industry's nitrous oxide emissions, and they will continue to do so for some time until older plants eventually retire and are replaced with newer plants. Another commenter recommends that the EPA update section 111(d) standards as soon as possible because these standards are long overdue and technology exists that is capable of reducing emissions.

One commenter states that the EPA should develop emission guidelines for existing sources to prevent ''grandfathering'' of existing sources that can occur when section 111(b) is used without concurrent use of section 111(d). The commenter states that the absence of emission guidelines for existing sources creates a disincentive to build new, more environmentally friendly sources. The commenter asserts that there is existing technology to limit emissions from existing sources that is likely cost-effective. Another commenter states that the EPA should develop standards for GHGs from existing nitric acid plants through the collaborative, iterative process of setting section 111(d) emission guidelines given the importance of GHG emissions from existing nitric acid plants.

Response: Emission guidelines for existing sources are developed concurrently or after standards of performance for new, modified, or reconstructed sources. See 40 CFR 60.22(a) (''Concurrently upon or after proposal of standards of performance for the control of a designated pollutant from affected facilities, the Administrator will publish a draft guideline document containing information pertinent to control of the designated pollutant from designated facilities.''). See also CAA section 111(d)(1) (emission guidelines are developed for existing sources in a source category for a pollutant ''to which a standard of performance under this section would apply if such existing source were a new source''). Under the NSPS program, the Agency only develops section 111(d) existing source emission guidelines for non-criteria pollutants and non-HAPs.

In this action, we are reviewing and revising the NO_X standard for new, modified, or reconstructed sources under section 111(b). As noted above, Section 111(d) does not provide authority to the Agency to set emission guidelines for existing sources for criteria pollutants, such as NO_X.

With respect to emissions guidelines for existing sources of GHGs, we are not taking final action with respect to GHG emissions from new, modified, or reconstructed sources in today's rule. As noted above, emissions guidelines for existing sources are set concurrently with or after standards for new, modified or reconstructed sources, and so we are also not taking any final action to develop emissions guidelines for existing sources of GHGs.

VI. Summary of Cost, Environmental, Energy, and Economic Impacts of These Standards

In setting standards, the CAA requires us to consider alternative emission control approaches, taking into account the estimated costs as well as impacts on energy, solid waste, and other effects.

A. What are the impacts for nitric acid production units?

We are presenting estimates of the impacts for 40 CFR part 60, Subpart Ga, the performance standards for new NAPUs constructed or reconstructed after October 14, 2011. The cost, environmental, and economic impacts presented in this section are expressed as incremental differences between the impacts of NAPUs complying with Subpart Ga and the current NSPS requirements of Subpart G (i.e., baseline). The impacts are presented for future NAPUs that commence construction, reconstruction, or modification over the five years following promulgation of the revised NSPS. To account for variation in the value of money over time, all annualized costs have been scaled to the 2nd quarter of 2010 using the Marshall and Swift Index. The analyses and the documents referenced below can be found in Docket ID No. EPA–HQ–OAR–2010–0750.

In order to determine the incremental impacts of this rule, we first estimated the number of new NAPUs that would become subject to regulation during the five year period after promulgation of Subpart Ga. Based on existing NAPUs and estimated future growth rates, six NAPUs are expected to trigger Subpart Ga NSPS in that five year period. In response to concerns from commenters, we have included five new NAPUs and one modified or reconstructed NAPU in the impact analysis for the final rule. For further detail on the methodology of these calculations, see memorandum *Impacts of Nitric Acid NSPS Review—NO_X (Updated Memo for Final NSPS),* in Docket ID No. EPA–HQ–OAR–2010–0750.

The Subpart Ga NO_X emission limit being promulgated in this action reflects the control technology currently in use by the industry. The Subpart G NSPS NO_X emissions limit can be achieved using a number of control techniques including NSCR, SCR and HPI. We expect most new facilities to employ SCR to comply with Subpart Ga. Since we expect new units will apply the same control technology to comply with the revised limit being promulgated in today's action as they would have applied to meet the current limit, there is no increase in control costs of meeting the emission limit of 0.50 lb NO_X/ton acid for new NAPUs.

There are differences in notification, testing, monitoring, reporting, and recordkeeping (MRR) between Subpart G and the new Subpart Ga that result in increased costs for new and modified NAPUs. These will include the capital cost of installing an air flow monitor and a dual span NO_X concentration monitor ($39,000 per NAPU and $23,000 per NAPU, respectively). These costs represent annualized costs of $15,000 per NAPU and $9,000 per NAPU, respectively. Annual costs will also be incurred for reporting, recordkeeping, and stack testing and total $72,000 for all six NAPUs. The incremental stack testing costs are due to the Appendix F requirements for annual rather than one-time testing for CEMS certification. They were inadvertently omitted from the cost analysis in the proposed rule. These increased costs are the only increased costs that will be incurred by new facilities as a result of the revised standards being promulgated in today's action. They are shown in Table 2.

The industry-wide cost estimate has been changed from the proposal. In the proposal we estimated that there would be six new sources during the first five years of the new Subpart Ga. We now estimate that there will be one modified source and five new sources during those five years. We estimate that the modified source would install an SCR system at a capital cost of $2.7 million and a total annualized cost of $370,000. The costs for the modified source are shown in Table 3.

The potential nationwide emission reduction associated with lowering the NO_X limit from 3.0 to 0.50 lb NO_X/ton acid (100 percent acid basis) is estimated to be about 2100 tons per year (tpy) NO_X.

At proposal, the estimated capital costs and annualized costs for Subpart Ga were $234,000, and $90,000, respectively. The cost effectiveness was

estimated at $45 per ton of NO_X. Based on the revised costs estimates discussed above, we currently estimate the final capital costs and annualized costs to be $3.1 million and $585,000, respectively, for all six of the production units projected to become subject to subpart Ga between 2012 and 2017. These costs result in a cost effectiveness of about $280 per ton of NO_X.

The estimated nationwide incremental 5-year NO_X emissions reductions and cost impacts for these revisions are summarized in Table 4 of this preamble. The methodology is detailed in the memorandum *Impacts of Nitric Acid NSPS Review—NO_X (Updated Memo for Final NSPS).* Further discussion of this cost effectiveness is available in the Section V of this preamble. As discussed in Section V, the cost effectiveness in this NSPS is reasonable and supported by previous NSPS for NO_X.

TABLE 2—NATIONAL INCREMENTAL NO_X EMISSION REDUCTIONS AND COST IMPACTS FOR NEW NITRIC ACID PRODUCTION UNITS SUBJECT TO STANDARDS UNDER 40 CFR PART 60, SUBPART Ga (FIFTH YEAR AFTER PROMULGATION)

Revisions for future affected facilities	Total capital cost [$1,000]	Total annualized cost [$1,000/yr]	Estimated annual NO_X emission reductions [tons NO_X/yr]	Estimated cost effectiveness [$/ton NO_X]
Revisions to NO_X emission limit	$0	$0	1806	.....
Revisions to MRR requirements	310	180	.....	.....
Total	310	180	1806	100

TABLE 3—NATIONAL INCREMENTAL NO_X EMISSION REDUCTIONS AND COST IMPACTS FOR MODIFIED OR RECONSTRUCTED NITRIC ACID PRODUCTION UNITS SUBJECT TO STANDARDS UNDER 40 CFR PART 60, SUBPART Ga (FIFTH YEAR AFTER PROMULGATION)

Revisions for future affected facilities	Total capital cost [$1,000]	Total annualized cost [$1,000/yr]	Estimated annual NO_X emission reductions [tons NO_X/yr]	Estimated cost effectiveness [$/ton NO_X]
Revisions to NO_X emission limit	$2,700	$370	299	$1,200
Revisions to MRR requirements	62	36	.....	.....
Total	2,762	406	299	1,360

TABLE 4—NATIONAL INCREMENTAL NO_X EMISSION REDUCTIONS AND COST IMPACTS FOR ALL NITRIC ACID PRODUCTION UNITS SUBJECT TO STANDARDS UNDER 40 CFR PART 60, SUBPART Ga (FIFTH YEAR AFTER PROMULGATION) *

Revisions for future affected facilities	Total capital cost [$1,000]	Total annualized cost [$1,000/yr]	Estimated annual NO_X emission reductions [tons NO_X/yr]	Estimated cost effectiveness [$/ton NO_X]
Revisions to NO_X emission limit	$2,700	$370	2,104	$176
Revisions to MRR requirements	372	215	.....	.....
Total	3,072	585	2,104	278

* Any small discrepancies between Tables 2, 3, and 4 are due to rounding.

B. What are the secondary impacts for nitric acid production units?

Indirect or secondary air quality impacts are impacts that would result from the increased electricity usage associated with the operation of control devices (i.e., increased secondary emissions of criteria pollutants from power plants). Energy impacts consist of the electricity and steam needed to operate control devices and other equipment that would be required under this final rule. The five new sources would likely install the same control systems to comply with the current Subpart G NO_X emission limit or this Subpart Ga NO_X emission limit. The revisions being finalized in today's rule require the addition of exhaust gas flow monitors and dual span NO_X concentration monitors, which would result in minimal secondary air impacts or increase in overall energy demand.

For the one modification expected to take place over the next five years, the installation of an SCR is expected. This addition will result in secondary air impacts and/or an increase in overall energy demand. However, the reductions in NO_X emissions achieved through installation of this control equipment will greatly outweigh any secondary air impacts associated with increased electricity use. See *Secondary Impact Analysis—SCR.*

C. What are the economic impacts for nitric acid production units?

We performed an economic impact analysis that estimates changes in prices and output for NAPUs nationally using the annual compliance costs estimated for this rule. All estimates are for the fifth year after promulgation since this is the year for which the compliance cost impacts are estimated. The impacts to producers and consumers affected by this rule are slightly higher product prices and slightly lower outputs. Prices for products (nitric acid) from affected plants should increase by less than 0.36 percent for the fifth year. The output of nitric acid should decrease by less than 1.20 percent for the fifth year. Hence, the overall economic impact of this

NSPS should be low on the affected industries and their consumers. For more information, please refer to the Economic Impact Analysis for this rulemaking in the public docket.

VII. Statutory and Executive Order Reviews

A. Executive Order 12866: Regulatory Planning and Review and Executive Order 13563: Improving Regulation and Regulatory Review

This action is not a ''significant regulatory action'' under the terms of Executive Order 12866 (58 FR 51735, October 4, 1993) and is therefore not subject to review under Executive Orders 12866 and 13563 (76 FR 3821, January 21, 2011).

B. Paperwork Reduction Act

The information collection requirements in this final rule have been submitted for approval to the Office of Management and Budget (OMB) under the Paperwork Reduction Act, 44 U.S.C. 3501 *et seq.* The information collection requirements are not enforceable until OMB approves them.

These revisions to the existing new source performance standards for NAPUs add monitoring requirements for future affected facilities. We have revised the ICR for the existing rule.

These revisions to the new source performance standards for NAPUs for future affected facilities include a change to the emission limit and additional continuous monitoring requirements. The monitoring requirements include installing a continuous flow monitor and a dual span NO_X concentration monitor, and monitoring the nitric acid production rate and concentration. These monitoring requirements are in addition to a CEMS for NO_X concentration which is required under the current Subpart G. These requirements are based on specific requirements in Subpart Ga which are mandatory for all operators subject to NSPS. These recordkeeping and reporting requirements are specifically authorized by section 114 of the CAA (42 U.S.C. 7414). All information submitted to the EPA pursuant to the recordkeeping and reporting requirements for which a claim of confidentiality is made is safeguarded according to the EPA policies set forth in 40 CFR part 2, subpart B.

When a malfunction occurs, sources must report them according to the applicable reporting requirements of 40 CFR part 60, subpart Ga. An affirmative defense to civil penalties for violations of emission standard that are caused by malfunctions is available to a source if it can demonstrate that certain criteria and requirements are satisfied. The criteria ensure that the affirmative defense is available only where the event that causes a violation of the emission standard meets the narrow definition of malfunction in 40 CFR 60.2 (sudden, infrequent, not reasonable preventable, and not caused by poor maintenance and or careless operation) and where the source took necessary actions to minimize emissions. In addition, the source must meet certain notification and reporting requirements. For example, the source must prepare a written root cause analysis and submit a written report to the Administrator documenting that it has met the conditions and requirements for assertion of the affirmative defense.

For this rule, EPA is adding affirmative defense to the estimate of burden in the ICR. To provide the public with an estimate of the relative magnitude of the burden associated with an assertion of the affirmative defense position adopted by a source, the EPA has provided administrative adjustments to this ICR that shows what the notification, recordkeeping, and reporting requirements associated with the assertion of the affirmative defense might entail. The EPA's estimate for the required notification, reports, and records, including the root cause analysis, associated with a single incident totals approximately $3,141, and is based on the time and effort required of a source to review relevant data, interview plant employees, and document the events surrounding a malfunction that has caused a violation of an emission standard. The estimate also includes time to produce and retain the record and reports for submission to the EPA.

The EPA provides this illustrative estimate of this burden because these costs are only incurred if there has been a violation and a source chooses to take advantage of the affirmative defense. Given the variety of circumstances under which malfunctions could occur, as well as differences among sources' operation and maintenance practices, we cannot reliably predict the severity and frequency of malfunction-related excess emissions events for a particular source. It is important to note that the EPA has no basis currently for estimating the number of malfunctions that would qualify for an affirmative defense. Current historical records would be an inappropriate basis, as source owners or operators previously operated their facilities in recognition that they were exempt from the requirement to comply with emissions standards during malfunctions. Of the number of violation events reported by source operators, only a small number would be expected to result from a malfunction (based on the definition above), and only a subset of violations caused by malfunctions would result in the source choosing to assert the affirmative defense. Thus, we believe the number of instances in which source operators might be expected to avail themselves of the affirmative defense will be extremely small.

For this reason, we estimate no more than 2 such occurrences for all sources subject to 40 CFR part 60, subpart Ga over the 3-year period covered by this ICR. We expect to gather information on such events in the future, and will revise this estimate as better information becomes available.

The annual burden for this information collection averaged over the first 3 years of this ICR is estimated to total 968 labor-hours per year at a cost of $91,800 per year. The annualized capital costs are estimated at $19,300 per year. The annualized operation and maintenance (O&M) costs are $23,500. The total annualized capital and O&M costs are $42,800 per year. Burden is defined at 5 CFR 1320.3(b).

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for the EPA's regulations in 40 CFR are listed in 40 CFR part 9.

C. Regulatory Flexibility Act (RFA) as Amended by the Small Business Regulatory Enforcement Fairness Act (RFA) of 1996 (SBREFA), 5 U.S.C. 601 et seq.

The Regulatory Flexibility Act (RFA) 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 this rule will not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small organizations, and small governmental jurisdictions.

For purposes of assessing the impacts of this rule on small entities, small entity is defined as: (1) A small business as defined by the Small Business Administration's regulations at 13 CFR 121.201; (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 rule on small entities, I certify that this action will not have a significant economic impact on a substantial number of small entities. This certification is based on the economic impact of this action to all affected small entities. Only four small entities may be impacted by this rule. This is an estimate that may overstate small entity impacts in that we assume each existing small entity will have a new source subject to this rule, which is unlikely. We estimate that all affected small entities will have annualized costs of less than 0.2 percent of their sales.

For more information on the small entity impacts associated with this rule, please refer to the Economic Impact and Small Business Analyses in the public docket. Although this rule would not have a significant economic impact on a substantial number of small entities, the EPA nonetheless tried to reduce the impact of this rule on small entities. When developing the revised standards, the EPA took special steps to ensure that the burdens imposed on small entities were minimal. The EPA conducted several meetings with industry trade associations to discuss regulatory options and the corresponding burden on industry, such as recordkeeping and reporting.

D. Unfunded Mandates Reform Act

This rule 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. This rule is not expected to impact state, local, or tribal governments. The nationwide annualized cost of this rule for affected industrial sources is $585,000/yr. Thus, this rule is not subject to the requirements of sections 202 and 205 of the Unfunded Mandates Reform Act (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. This rule will not apply to such governments and will not impose any obligations upon them.

E. Executive Order 13132, Federalism

This action 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. Nitric acid plants are privately owned companies and there will be no direct impact on states and other federal offices. Thus, Executive Order 13132 does not apply to this rule. In the spirit of Executive Order 13132, and consistent with the EPA policy to promote communications between the EPA and state and local governments, the EPA specifically solicited comment on this 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). It will not have substantial direct effects on tribal governments, on the relationship between the federal government and Indian tribes, or on the distribution of power and responsibilities between the federal government and Indian tribes, as specified in Executive Order 13175. This rule imposes requirements on owners and operators of NAPUs and not tribal governments. We do not know of any NAPUs owned or operated by Indian tribal governments. However, if there are any, the effect of this rule on communities of tribal governments would not be unique or disproportionate to the effect on other communities. Thus, Executive Order 13175 does not apply to this action.

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

The EPA interprets Executive Order 13045 (62 F.R. 19885, April 22, 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. Nevertheless, this action will result in reductions in NO_X emissions which will provide some increased protection of health for people of all ages including children.

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

This action 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 energy effect on the supply, distribution, or use of energy. This action will not create any new requirements for sources in the energy supply, distribution, or use sectors.

I. National Technology Transfer and Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act of 1995 (''NTTAA''), Public Law 104–113 (15 U.S.C. 272 note), directs the 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, business practices) that are developed or adopted by voluntary consensus standards bodies. NTTAA directs the EPA to provide Congress, through OMB, explanations when the Agency decides not to use available and applicable VCS.

This final rulemaking involves technical standards. The EPA is using the following: ASTM D6348–03, Standard Test Method for Determination of Gaseous Compounds by Extractive Direct Interface Fourier Transform Infrared (FTIR) Spectroscopy, and ASTM E1584–11, Standard Test Method for Assay of Nitric Acid, which have been incorporated by reference.

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.

The EPA has determined that this final rule will not have disproportionately high and adverse human health or environmental effects on minority or low-income populations because it increases the level of environmental protection for all affected populations without having any disproportionately high and adverse human health or environmental effects on any population, including any minority or low-income population. The EPA has also determined that a proximity-based demographic study comparing populations in closest proximity to the regulated sources to the

general population is not appropriate for this rulemaking due to lack of pollutants with localized effects.

K. Congressional Review Act

The Congressional Review Act, 5 U.S.C. 801, *et seq.*, as added by the Small Business Regulatory Enforcement Fairness Act of 1996, generally provides that, before a rule may take effect, the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of the Congress and to the Comptroller General of the United States. The EPA will submit a report containing this final rule and other required information to the United States Senate, the United States House of Representatives, and the Comptroller General of the United States prior to publication of the final rule in the **Federal Register**. A major rule cannot take effect until 60 days after it is published in the **Federal Register**. This action is not a ''major rule'' as defined by 5 U.S.C. 804(2). The final rules will be effective on August 14, 2012.

List of Subjects in 40 CFR Part 60

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

Dated: May 14, 2012.

Lisa P. Jackson,

Administrator.

For the reasons stated in the preamble, title 40, chapter I, of the Code of Federal Regulations is 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 revising paragraph (a)(82), adding and reserving paragraphs (a)(97) and (a)(98), and adding paragraph (a)(99) to read as follows:

§ 60.17 Incorporations by reference.

* * * * *

(a) * * *

(82) ASTM D6348–03, Standard Test Method for Determination of Gaseous Compounds by Extractive Direct Interface Fourier Transform Infrared (FTIR) Spectroscopy, approved October 1, 2003, IBR approved for § 60.73a(b) of subpart Ga of this part, table 7 of subpart IIII of this part, and table 2 of subpart JJJJ of this part.

* * * * *

(99) ASTM E1584–11, Standard Test Method for Assay of Nitric Acid, approved August 1, 2011, IBR approved for § 60.73a(c) of subpart Ga of this part.

* * * * *

■ 3. Section 60.70 is amended by revising paragraph (b) to read as follows:

§ 60.70 Applicability and designation of affected facility.

* * * * *

(b) Any facility under paragraph (a) of this section that commences construction or modification after August 17, 1971, and on or before October 14, 2011 is subject to the requirements of this subpart. Any facility that commences construction or modification after October 14, 2011 is subject to subpart Ga of this part.

■ 4. Add Subpart Ga to read as follows:

Subpart Ga—Standards of Performance for Nitric Acid Plants for Which Construction, Reconstruction, or Modification Commenced After October 14, 2011

Sec.

60.70a Applicability and designation of affected facility.
60.71a Definitions.
60.72a Standards.
60.73a Emissions testing and monitoring.
60.74a Affirmative defense for violations of emission standards during malfunction.
60.75a Calculations.
60.76a Recordkeeping.
60.77a Reporting.

Subpart Ga—Standards of Performance for Nitric Acid Plants for Which Construction, Reconstruction, or Modification Commenced After October 14, 2011

§ 60.70a Applicability and designation of affected facility.

(a) The provisions of this subpart are applicable to each nitric acid production unit, which is the affected facility.

(b) This subpart applies to any nitric acid production unit that commences construction or modification after October 14, 2011.

§ 60.71a Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in subpart A of this part.

Affirmative defense means, in the context of an enforcement proceeding, a response or defense put forward by a defendant, regarding which the defendant has the burden of proof, and the merits of which are independently and objectively evaluated in a judicial or administrative proceeding.

Monitoring system malfunction means a sudden, infrequent, not reasonably preventable failure of the monitoring system to provide valid data. Monitoring system failures that are caused in part by poor maintenance or careless operation are not malfunctions. You are required to implement monitoring system repairs in response to monitoring system malfunctions or out-of-control periods, and to return the monitoring system to operation as expeditiously as practicable.

Nitric acid production unit means any facility producing weak nitric acid by either the pressure or atmospheric pressure process.

Operating day means a 24-hour period beginning at 12:00 a.m. during which the nitric acid production unit operated at any time during this period.

Weak nitric acid means acid which is 30 to 70 percent in strength.

§ 60.72a Standards.

Nitrogen oxides. On and after the date on which the performance test required to be conducted by § 60.73a(e) is completed, you may not discharge into the atmosphere from any affected facility any gases which contain NO_X, expressed as NO_2, in excess of 0.50 pounds (lb) per ton of nitric acid produced, as a 30-day emission rate calculated based on 30 consecutive operating days, the production being expressed as 100 percent nitric acid. The emission standard applies at all times.

§ 60.73a Emissions testing and monitoring.

(a) *General emissions monitoring requirements.* You must install and operate a NO_X concentration (ppmv) continuous emissions monitoring system (CEMS). You must also install and operate a stack gas flow rate monitoring system. With measurements of stack gas NO_X concentration and stack gas flow rate, you will determine hourly NO_X emissions rate (e.g., lb/hr) and with measured data of the hourly nitric acid production (tons), calculate emissions in units of the applicable emissions limit (lb/ton of 100 percent acid produced). You must operate the monitoring system and report emissions during all operating periods including unit startup and shutdown, and malfunction.

(b) *Nitrogen oxides concentration continuous emissions monitoring system.* (1) You must install, calibrate, maintain, and operate a CEMS for measuring and recording the concentration of NO_X emissions in accordance with the provisions of § 60.13 and Performance Specification 2

of Appendix B and Procedure 1 of Appendix F of this part. You must use cylinder gas audits to fulfill the quarterly auditing requirement at section 5.1 of Procedure 1 of Appendix F of this part for the NO_X concentration CEMS.

(2) For the NO_X concentration CEMS, use a span value, as defined in Performance Specification 2, section 3.11, of Appendix B of this part, of 500 ppmv (as NO_2). If you emit NO_X at concentrations higher than 600 ppmv (e.g., during startup or shutdown periods), you must apply a second CEMS or dual range CEMS and a second span value equal to 125 percent of the maximum estimated NO_X emission concentration to apply to the second CEMS or to the higher of the dual analyzer ranges during such periods.

(3) For conducting the relative accuracy test audits, per Performance Specification 2, section 8.4, of Appendix B of this part and Procedure 1, section 5.1.1, of Appendix F of this part, use either EPA Reference Method 7, 7A, 7C, 7D, or 7E of Appendix A–4 of this part; EPA Reference Method 320 of Appendix A of part 63 of this chapter; or ASTM D6348–03 (incorporated by reference, see § 60.17). To verify the operation of the second CEMS or the higher range of a dual analyzer CEMS described in paragraph (b)(2) of this section, you need not conduct a relative accuracy test audit but only the calibration drift test initially (found in Performance Specification 2, section 8.3.1, of Appendix B of this part) and the cylinder gas audit thereafter (found in Procedure 1, section 5.1.2, of Appendix F of this part).

(4) If you use EPA Reference Method 7E of Appendix A–4 of this part, you must mitigate loss of NO_2 in water according to the requirements in paragraphs (b)(4)(i), (ii), or (iii) of this section and verify performance by conducting the system bias checks required in EPA Reference Method 7E, section 8, of Appendix A–4 of this part according to (b)(4)(iv) of this section, or follow the dynamic spike procedure according to paragraph (b)(4)(v) of this section.

(i) For a wet-basis measurement system, you must measure and report temperature of sample line and components (up to analyzer inlet) to demonstrate that the temperatures remain above the sample gas dew point at all times during the sampling.

(ii) You may use a dilution probe to reduce the dew point of the sample gas.

(iii) You may use a refrigerated-type condenser or similar device (e.g., permeation dryer) to remove condensate continuously from sample gas while maintaining minimal contact between condensate and sample gas.

(iv) If your analyzer measures nitric oxide (NO) and nitrogen dioxide (NO_2) separately, you must use both NO and NO_2 calibration gases. Otherwise, you must substitute NO_2 calibration gas for NO calibration gas in the performance of system bias checks.

(v) You must conduct dynamic spiking according to EPA Reference Method 7E, section 16.1, of Appendix A–4 of this part using NO_2 as the spike gas.

(5) Instead of a NO_X concentration CEMS meeting Performance Specification 2, you may apply an FTIR CEMS meeting the requirements of Performance Specification 15 of Appendix B of this part to measure NO_X concentrations. Should you use an FTIR CEMS, you must replace the Relative Accuracy Test Audit requirements of Procedure 1 of appendix F of this part with the validation requirements and criteria of Performance Specification 15, sections 11.1.1 and 12.0, of Appendix B of this part.

(c) *Determining NO_X mass emissions rate values.* You must use the NO_X concentration CEMS, acid production, gas flow rate monitor and other monitoring data to calculate emissions data in units of the applicable limit (lb NO_X/ton of acid produced expressed as 100 percent nitric acid).

(1) You must install, calibrate, maintain, and operate a CEMS for measuring and recording the stack gas flow rates to use in combination with data from the CEMS for measuring emissions concentrations of NO_X to produce data in units of mass rate (e.g., lb/hr) of NO_X on an hourly basis. You will operate and certify the continuous emissions rate monitoring system (CERMS) in accordance with the provisions of § 60.13 and Performance Specification 6 of Appendix B of this part. You must comply with the following provisions in (c)(1)(i) through (iii) of this section.

(i) You must use a stack gas flow rate sensor with a full scale output of at least 125 percent of the maximum expected exhaust volumetric flow rate (see Performance Specification 6, section 8, of Appendix B of this part).

(ii) For conducting the relative accuracy test audits, per Performance Specification 6, section 8.2 of Appendix B of this part and Procedure 1, section 5.1.1, of Appendix F of this part, you must use either EPA Reference Method 2, 2F, or 2G of Appendix A–4 of this part. You may also apply Method 2H in conjunction with other velocity measurements.

(iii) You must verify that the CERMS complies with the quality assurance requirements in Procedure 1 of Appendix F of this part. You must conduct relative accuracy testing to provide for calculating the relative accuracy for RATA and RAA determinations in units of lb/hour.

(2) You must determine the nitric acid production parameters (production rate and concentration) by installing, calibrating, maintaining, and operating a permanent monitoring system (e.g., weigh scale, volume flow meter, mass flow meter, tank volume) to measure and record the weight rates of nitric acid produced in tons per hour. If your nitric acid production rate measurements are for periods longer than hourly (e.g., daily values), you will determine average hourly production values, tons acid/hr, by dividing the total acid production by the number of hours of process operation for the subject measurement period. You must comply with the following provisions in (c)(2)(i) through (iv) of this section.

(i) You must verify that each component of the monitoring system has an accuracy and precision of no more than ±5 percent of full scale.

(ii) You must analyze product concentration via titration or by determining the temperature and specific gravity of the nitric acid. You may also use ASTM E1584–11 (incorporated by reference, see § 60.17), for determining the concentration of nitric acid in percent. You must determine product concentration daily.

(iii) You must use the acid concentration to express the nitric acid production as 100 percent nitric acid.

(iv) You must record the nitric acid production, expressed as 100 percent nitric acid, and the hours of operation.

(3) You must calculate hourly NO_X emissions rates in units of the standard (lb/ton acid) for each hour of process operation. For process operating periods for which there is little or no acid production (e.g., startup or shutdown), you must use the average hourly acid production rate determined from the data collected over the previous 30 days of normal acid production periods (see § 60.75a).

(d) *Continuous monitoring system.* For each continuous monitoring system, including NO_X concentration measurement, volumetric flow rate measurement, and nitric acid production measurement equipment, you must meet the requirements in paragraphs (d)(1) through (3) of this section.

(1) You must operate the monitoring system and collect data at all required intervals at all times the affected facility

is operating except for periods of monitoring system malfunctions or out-of-control periods as defined in Appendix F, sections 4 and 5, of this part, repairs associated with monitoring system malfunctions or out-of-control periods, and required monitoring system quality assurance or quality control activities including, as applicable, calibration checks and required zero and span adjustments.

(2) You may not use data recorded during monitoring system malfunctions or out-of-control periods, repairs associated with monitoring system malfunctions or out-of-control periods, or required monitoring system quality assurance or control activities in calculations used to report emissions or operating levels. You must use all the data collected during all other periods in calculating emissions and the status of compliance with the applicable emissions limit in accordance with § 60.72a(a).

(e) *Initial performance testing.* You must conduct an initial performance test to demonstrate compliance with the NO_X emissions limit under § 60.72a(a) beginning in the calendar month following initial certification of the NO_X and flow rate monitoring CEMS. The initial performance test consists of collection of hourly NO_X average concentration, mass flow rate recorded with the certified NO_X concentration and flow rate CEMS and the corresponding acid generation (tons) data for all of the hours of operation for the first 30 days beginning on the first day of the first month following completion of the CEMS installation and certification as described above. You must assure that the CERMS meets all of the data quality assurance requirements as per § 60.13 and Appendix F, Procedure 1, of this part and you must use the data from the CERMS for this compliance determination.

§ 60.74a Affirmative defense for violations of emission standards during malfunction.

In response to an action to enforce the standards set forth in § 60.72a, you may assert an affirmative defense to a claim for civil penalties for violations of such standards that are caused by malfunction, as defined at 40 CFR 60.2. Appropriate penalties may be assessed, however, if you fail to meet your burden of proving all of the requirements in the affirmative defense. The affirmative defense shall not be available for claims for injunctive relief.

(a) To establish the affirmative defense in any action to enforce such a standard, you must timely meet the reporting requirements in paragraph (b) of this section, and must prove by a preponderance of evidence that:

(1) The violation:

(i) Was caused by a sudden, infrequent, and unavoidable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner; and

(ii) Could not have been prevented through careful planning, proper design or better operation and maintenance practices; and

(iii) Did not stem from any activity or event that could have been foreseen and avoided, or planned for; and

(iv) Was not part of a recurring pattern indicative of inadequate design, operation, or maintenance; and

(2) Repairs were made as expeditiously as possible when a violation occurred. Off-shift and overtime labor were used, to the extent practicable to make these repairs; and

(3) The frequency, amount, and duration of the violation (including any bypass) were minimized to the maximum extent practicable; and

(4) If the violation resulted from a bypass of control equipment or a process, then the bypass was unavoidable to prevent loss of life, personal injury, or severe property damage; and

(5) All possible steps were taken to minimize the impact of the violation on ambient air quality, the environment, and human health; and

(6) All emissions monitoring and control systems were kept in operation if at all possible, consistent with safety and good air pollution control practices; and

(7) All of the actions in response to the violation were documented by properly signed, contemporaneous operating logs; and

(8) At all times, the affected facility was operated in a manner consistent with good practices for minimizing emissions; and

(9) A written root cause analysis has been prepared, the purpose of which is to determine, correct, and eliminate the primary causes of the malfunction and the violation resulting from the malfunction event at issue. The analysis shall also specify, using best monitoring methods and engineering judgment, the amount of any emissions that were the result of the malfunction.

(b) *Report.* The owner or operator seeking to assert an affirmative defense shall submit a written report to the Administrator with all necessary supporting documentation, that it has met the requirements set forth in paragraph (a) of this section. This affirmative defense report shall be included in the first periodic compliance, deviation report or excess emission report otherwise required after the initial occurrence of the violation of the relevant standard (which may be the end of any applicable averaging period). If such compliance, deviation report or excess emission report is due less than 45 days after the initial occurrence of the violation, the affirmative defense report may be included in the second compliance, deviation report or excess emission report due after the initial occurrence of the violation of the relevant standard.

§ 60.75a Calculations.

(a) You must calculate the 30 operating day rolling arithmetic average emissions rate in units of the applicable emissions standard (lb NO_X/ton 100 percent acid produced) at the end of each operating day using all of the quality assured hourly average CEMS data for the previous 30 operating days.

(b) You must calculate the 30 operating day average emissions rate according to Equation 1:

$$E_{30} = \frac{k \frac{1}{n} \sum_{i=1}^{n} C_i Q_i}{P_i} \qquad \text{(Eq. 1)}$$

Where:

E_{30} = 30 operating day average emissions rate of NO_X, lb NO_X/ton of 100 percent HNO_3;

C_i = concentration of NO_X for hour i, ppmv;

Q_i = volumetric flow rate of effluent gas for hour i, where C_i and Q_i are on the same basis (either wet or dry), scf/hr;

P_i = total acid produced during production hour i, tons 100 percent HNO_3;

k = conversion factor, 1.194×10^{-7} for NO_X; and

n = number of operating hours in the 30 operating day period, i.e., n is between 30 and 720.

§ 60.76a Recordkeeping.

(a) For the NO_X emissions rate, you must keep records for and results of the performance evaluations of the continuous emissions monitoring systems.

(b) You must maintain records of the following information for each 30 operating day period:

(1) Hours of operation.

(2) Production rate of nitric acid, expressed as 100 percent nitric acid.

(3) 30 operating day average NO_X emissions rate values.

(c) You must maintain records of the following time periods:

(1) Times when you were not in compliance with the emissions standards.

(2) Times when the pollutant concentration exceeded full span of the NO_X monitoring equipment.

(3) Times when the volumetric flow rate exceeded the high value of the

volumetric flow rate monitoring equipment.

(d) You must maintain records of the reasons for any periods of noncompliance and description of corrective actions taken.

(e) You must maintain records of any modifications to CEMS which could affect the ability of the CEMS to comply with applicable performance specifications.

(f) For each malfunction, you must maintain records of the following information:

(1) Records of the occurrence and duration of each malfunction of operation (i.e., process equipment) or the air pollution control and monitoring equipment.

(2) Records of actions taken during periods of malfunction to minimize emissions in accordance with § 60.11(d), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation.

§ 60.77a Reporting.

(a) The performance test data from the initial and subsequent performance tests and from the performance evaluations of the continuous monitors must be submitted to the Administrator at the appropriate address as shown in 40 CFR 60.4.

(b) The following information must be reported to the Administrator for each 30 operating day period where you were not in compliance with the emissions standard:

(1) Time period;

(2) NO_X emission rates (lb/ton of acid produced);

(3) Reasons for noncompliance with the emissions standard; and

(4) Description of corrective actions taken.

(c) You must also report the following whenever they occur:

(1) Times when the pollutant concentration exceeded full span of the NO_X pollutant monitoring equipment.

(2) Times when the volumetric flow rate exceeded the high value of the volumetric flow rate monitoring equipment.

(d) You must report any modifications to CERMS which could affect the ability of the CERMS to comply with applicable performance specifications.

(e) Within 60 days of completion of the relative accuracy test audit (RATA) required by this subpart, you must submit the data from that audit to EPA's WebFIRE database by using the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/SSL/cdx/EPA_Home.asp*). You must submit performance test data in the file format generated through use of EPA's Electronic Reporting Tool (ERT) (*http://www.epa.gov/ttn/chief/ert/index.html*). Only data collected using test methods listed on the ERT Web site are subject to this requirement for submitting reports electronically to WebFIRE. Owners or operators who claim that some of the information being submitted for performance tests is confidential business information (CBI) must submit a complete ERT file including information claimed to be CBI on a compact disk or other commonly used electronic storage media (including, but not limited to, flash drives) by registered letter to EPA and the same ERT file with the CBI omitted to EPA via CDX as described earlier in this paragraph. Mark the compact disk or other commonly used electronic storage media clearly as CBI and mail to U.S. EPA/OAPQS/CORE CBI Office, Attention: WebFIRE Administrator, MD C404–02, 4930 Old Page Rd., Durham, NC 27703. At the discretion of the delegated authority, you must also submit these reports to the delegated authority in the format specified by the delegated authority. You must submit the other information as required in the performance evaluation as described in § 60.2 and as required in this chapter.

(f) If a malfunction occurred during the reporting period, you must submit a report that contains the following:

(1) The number, duration, and a brief description for each type of malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded.

(2) A description of actions taken by an owner or operator during a malfunction of an affected facility to minimize emissions in accordance with § 60.11(d), including actions taken to correct a malfunction.

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FEDERAL COMMUNICATIONS COMMISSION

47 CFR Part 51

[WC Docket Nos. 10–90, 07–135, 05–337, 03–109; GN Docket No. 09–51; CC Docket Nos. 01–92, 96–45; WT Docket No. 10–208; DA 12–870]

Connect America Fund; A National Broadband Plan for Our Future; Establishing Just and Reasonable Rates for Local Exchange Carriers; High-Cost Universal Service Support

AGENCY: Federal Communications Commission.

ACTION: Final rule.

SUMMARY: In this document, the Federal Communications Commission revises and clarifies certain provisions of its rules relating to the transition of intrastate switched access rates and the operation of the transitional recovery mechanism that were adopted in the *USF/ICC Transformation Order.* The Commission also grants a number of limited waivers of the Commission's rules to address administrative concerns and rule inconsistencies.

DATES: Effective September 13, 2012.

FOR FURTHER INFORMATION CONTACT: Belinda Nixon, Wireline Competition Bureau, (202) 418–1520.

SUPPLEMENTARY INFORMATION: This is a summary of the Wireline Competition Bureau's Order in WC Docket Nos. 10–90, 07–135, 05–337, 03–109; GN Docket No. 09–51; CC Docket Nos. 01–92, 96–45; WT Docket No. 10–208; DA 12–870, released on June 5, 2012. The full text of this document is available for public inspection during regular business hours in the FCC Reference Center, Room CY–A257, 445 12th Street SW., Washington, DC 20554, and at the following Internet address: *http://transition.fcc.gov/Daily_Releases/Daily_Business/2012/db0425/FCC-12-47A1.pdf.* The complete text may be purchased from the Commission's duplicating contractor, Best Copy and Printing, Inc. (BCPI), Portals II, 445 12th Street SW., Room CY–B402, Washington, DC 20554, (202) 488–5300, facsimile (202) 488–5563, or via email at *fcc@bcpiweb.com.*

I. Introduction

1. In the *USF/ICC Transformation Order,* the Commission delegated to the Wireline Competition Bureau (Bureau) the authority to revise and clarify rules as necessary to ensure that the reforms adopted in the *USF/ICC Transformation Order* are properly reflected in the rules. In this Order, the Bureau acts pursuant to this delegated authority to revise and

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Part II

Environmental Protection Agency

40 CFR Parts 60 and 63

Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews; Final Rule

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 60 and 63

[EPA–HQ–OAR–2010–0505; FRL–9665–1]

RIN 2060–AP76

Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: This action finalizes the review of new source performance standards for the listed oil and natural gas source category. In this action the EPA revised the new source performance standards for volatile organic compounds from leaking components at onshore natural gas processing plants and new source performance standards for sulfur dioxide emissions from natural gas processing plants. The EPA also established standards for certain oil and gas operations not covered by the existing standards. In addition to the operations covered by the existing standards, the newly established standards will regulate volatile organic compound emissions from gas wells, centrifugal compressors, reciprocating compressors, pneumatic controllers and storage vessels. This action also finalizes the residual risk and technology review for the Oil and Natural Gas Production source category and the Natural Gas Transmission and Storage source category. This action includes revisions to the existing leak detection and repair requirements. In addition, the EPA has established in this action emission limits reflecting maximum achievable control technology for certain currently uncontrolled emission sources in these source categories. This action also includes modification and addition of testing and monitoring and related notification, recordkeeping and reporting requirements, as well as other minor technical revisions to the national emission standards for hazardous air pollutants. This action finalizes revisions to the regulatory provisions related to emissions during periods of startup, shutdown and malfunction.

DATES: This final rule is effective on October 15, 2012. The incorporation by reference of certain publications listed in this rule is approved by the Director of the Federal Register as of October 15, 2012.

ADDRESSES: The EPA has established a docket for this action under Docket ID. No. EPA–HQ–OAR–2010–0505. All documents in the docket are listed on the *http://www.regulations.gov* Web site. Although listed in the index, some information is not publicly available, *e.g.,* confidential business information or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the Internet and will be publicly available only in hard copy form. Publicly available docket materials are available either electronically through *http://www.regulations.gov* or in hard copy at the EPA's Docket Center, Public Reading Room, EPA West Building, Room Number 3334, 1301 Constitution Avenue NW., Washington, DC 20004. This Docket Facility is open from 8:30 a.m. to 4:30 p.m. Eastern Standard Time, Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the Air Docket is (202) 566–1742.

FOR FURTHER INFORMATION CONTACT: For further information about this final action, contact Mr. Bruce Moore, Sector Policies and Programs Division (E143–05), Office of Air Quality and Standards, Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone number: (919) 541–5460; facsimile number: (919) 685–3200; email address: *moore.bruce@epa.gov.* For additional contact information, see the following **SUPPLEMENTARY INFORMATION** section.

SUPPLEMENTARY INFORMATION: For specific information regarding risk assessment and exposure modeling methodology, contact Mr. Mark Morris, Health and Environmental Impacts Division (C504–06), Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, NC 27711; telephone number (919) 541–5416; fax number: (919) 541–0840; and email address: *morris.mark@epa.gov.*

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I. Preamble Acronyms and Abbreviations

Several acronyms and terms used to describe industrial processes, data inventories and risk modeling are included in this preamble. While this may not be an exhaustive list, to ease the reading of this preamble and for reference purposes, the following terms and acronyms are defined here:

API American Petroleum Institute
BACT Best Available Control Technology
BDT Best Demonstrated Technology
bpd Barrels Per Day
BMP Best Management Practice
BSER Best System of Emission Reduction
BTEX Benzene, Ethylbenzene, Toluene and Xylene
CAA Clean Air Act
CBM Coal Bed Methane
CDX Central Data Exchange
CEDRI Compliance and Emissions Data Reporting Interface
CFR Code of Federal Regulations
CO Carbon Monoxide
CO_2 Carbon Dioxide
CO_2e Carbon Dioxide Equivalent
DOE United States Department of Energy
e-GGRT Electronic Greenhouse Gas Reporting Tool
EPA Environmental Protection Agency
ERPG Emergency Response Planning Guidelines
ERT Electronic Reporting Tool
GCG Gas Condensate Glycol
GHG Greenhouse Gas
GOR Gas to Oil Ratio
GWP Global Warming Potential
HAP Hazardous Air Pollutants
HEM–3 Human Exposure Model, version 3
HI Hazard Index
HP Horsepower
HQ Hazard Quotient
H_2S Hydrogen Sulfide
ICR Information Collection Request
IPCC Intergovernmental Panel on Climate Change
IRIS Integrated Risk Information System
km Kilometer
kW Kilowatts
LAER Lowest Achievable Emission Rate
lb Pounds
LDAR Leak Detection and Repair
MACT Maximum Achievable Control Technology
MACT Code NEI code used to identify processes included in a source category
Mcf Thousand Cubic Feet
Mg/yr Megagrams per year
MIR Maximum Individual Risk
MIRR Monitoring, Inspection, Recordkeeping and Reporting
$MMtCO_2e$ Million Metric Tons of Carbon Dioxide Equivalents
NAAQS National Ambient Air Quality Standards
NAC/AEGL National Advisory Committee for Acute Exposure Guideline Levels for Hazardous Substances
NAICS North American Industry Classification System
NAS National Academy of Sciences
NATA National Air Toxics Assessment
NEI National Emissions Inventory
NEMS National Energy Modeling System
NESHAP National Emissions Standards for Hazardous Air Pollutants
NGL Natural Gas Liquids
NIOSH National Institutes for Occupational Safety and Health
NO_X Oxides of Nitrogen
NRC National Research Council
NSPS New Source Performance Standards
NSR New Source Review
NTTAA National Technology Transfer and Advancement Act
OAQPS Office of Air Quality Planning and Standards
OMB Office of Management and Budget
PB–HAP Hazardous air pollutants known to be persistent and bio-accumulative in the environment
PFE Potential for Flash Emissions
PM Particulate Matter
$PM_{2.5}$ Particulate Matter (2.5 microns and less)
POM Polycyclic Organic Matter
ppm Parts per Million
ppmv Parts per Million by Volume
PSIG Pounds per Square Inch Gauge
PSIA Pounds per Square Inch Absolute
PTE Potential to Emit
QA Quality Assurance
RACT Reasonably Available Control Technology
RBLC RACT/BACT/LAER Clearinghouse
REC Reduced Emissions Completions
REL California EPA Reference Exposure Level
RFA Regulatory Flexibility Act
RfC Reference Concentration
RfD Reference Dose
RIA Regulatory Impact Analysis
RICE Reciprocating Internal Combustion Engines
RTR Residual Risk and Technology Review
SAB Science Advisory Board
SBREFA Small Business Regulatory Enforcement Fairness Act
SCC Source Classification Codes
scfh Standard Cubic Feet Per Hour
scfm Standard Cubic Feet Per Minute
scm Standard Cubic Meters
scmd Standard Cubic Meters per Day
SCOT Shell Claus Offgas Treatment
SIP State Implementation Plan
SISNOSE Significant Economic Impact on a Substantial Number of Small Entities
S/L/T State and Local and Tribal Agencies
SO_2 Sulfur Dioxide
SSM Startup, Shutdown and Malfunction
STEL Short-term Exposure Limit
TLV Threshold Limit Value
TOSHI Target Organ-Specific Hazard Index
tpy Tons per Year
TRIM Total Risk Integrated Modeling System
TRIM.FaTE A spatially explicit, compartmental mass balance model that describes the movement and transformation of pollutants over time, through a user-defined, bounded system that includes both biotic and abiotic compartments
TSD Technical Support Document
UF Uncertainty Factor
UMRA Unfunded Mandates Reform Act
URE Unit Risk Estimate
VCS Voluntary Consensus Standards
VOC Volatile Organic Compounds
VRU Vapor Recovery Unit

II. General Information

A. Executive Summary

1. Purpose of the Regulatory Action

Responding to the requirements of a consent decree, this action finalizes several rules that apply to the oil and gas production industry and significantly reduce emissions of air pollutants. More particularly, the action finalizes:

- New source performance standards (NSPS) for the Crude Oil and Natural Gas Production and onshore natural gas processing plant source category. The EPA reviewed two existing NSPS for onshore natural gas processing plant source category under section 111(b) of the Clean Air Act (CAA). This action improves the existing NSPS and finalizes standards for certain crude oil and natural gas sources that are not covered by existing NSPS for this sector.
- National Emissions Standards for Hazardous Air Pollutants (NESHAP) for the Oil and Natural Gas Production source category and the Natural Gas Transmission and Storage source category. The EPA conducted risk and technology reviews (RTR) for these rules under section 112 of the CAA. In addition, the EPA has established emission limits for certain currently uncontrolled emission sources in these

source categories. These limits reflect maximum achievable control technology (MACT).

2. Summary of the Major Provisions of the Regulatory Actions

New Source Performance Standards (NSPS). The newly established NSPS for the Crude Oil and Natural Gas Production source category regulate volatile organic compound (VOC) emissions from gas wells, centrifugal compressors, reciprocating compressors, pneumatic controllers, storage vessels and leaking components at onshore natural gas processing plants, as well as sulfur dioxide (SO_2) emissions from onshore natural gas processing plants. This rule sets cost-effective performance standards for:

Gas wells. The rule covers any gas well that is ''an onshore well drilled principally for production of natural gas.'' Oil wells (wells drilled principally for the production of crude oil) are not subject to this rule. For fractured and refractured gas wells, the rule generally requires owners/operators to use reduced emissions completions, also known as ''RECs'' or ''green completions,'' to reduce VOC emissions from well completions. To achieve these VOC reductions, owners and/or operators may use RECs or completion combustion devices, such as flaring, until January 1, 2015; as of January 1, 2015, owners and/or operators must use RECs and a completion combustion device. The rule does not require RECs where their use is not feasible, as specified in the rule. See sections IX.A and IX.B of this preamble for further discussion.

Storage vessels. Individual storage vessels in the oil and natural gas production segment and the natural gas processing, transmission and storage segments with emissions equal to or greater than 6 tons per year (tpy) must achieve at least 95.0 percent reduction in VOC emissions. See section IX.E of this preamble for further discussion.

Certain controllers. The rule sets a natural gas bleed rate limit of 6 scfh for individual, continuous bleed, natural gas-driven pneumatic controllers located between the wellhead and the point at which the gas enters the transmission and storage segment. For individual, continuous bleed, natural gas-driven pneumatic controllers located at natural gas processing plants, the rule sets a natural gas bleed limit of zero scfh. See section IX.C of this preamble for further discussion.

Certain compressors. The rule requires a 95.0 percent reduction of VOC emissions from wet seal centrifugal compressors located between the wellhead and the point at which the gas enters the transmission and storage segment. The rule also requires measures intended to reduce VOC emissions from reciprocating compressors located between the wellhead and the point where natural gas enters the natural gas transmission and storage segment. Owners and/or operators of these compressors must replace the rod packing based on specified usage or time. See section IX.D of this preamble for further discussion.

For onshore natural gas processing plants, this final action revises the existing NSPS requirements for leak detection and repair (LDAR) to reflect the procedures and leak thresholds established in the NSPS for Equipment Leaks of VOCs in the Synthetic Organic Chemicals Manufacturing Industry. This final action also revises the existing NSPS requirements for SO_2 emission reductions 99.8 percent to 99.9 percent based on reanalysis of the original data.

National Emissions Standards for Hazardous Air Pollutants (NESHAP). This action also revises the NESHAP for glycol dehydration unit process vents and leak detection and repair (LDAR) requirements. In the final rule for major sources at oil and natural gas production facilities, we have lowered the leak definition for valves at natural gas processing plants to 500 parts per million (ppm) and thus require the application of LDAR procedures at this level. In this final rule, we also have established MACT standards for ''small'' glycol dehydration units, which were unregulated under the initial NESHAP. Covered glycol dehydrators are those with an actual annual average natural gas flow rate less than 85,000 standard cubic meters per day (scmd) or actual average benzene emissions less than 1 ton per year (tpy), and they must meet unit-specific limits for benzene, ethylbenzene, toluene and xylene (BTEX).

In the final rule for major sources at natural gas transmission and storage facilities, we have established MACT standards for ''small'' glycol dehydrators also not regulated under the initial NESHAP. Covered glycol dehydrators are those with an actual annual average natural gas flow rate less than 283,000 scmd or actual average benzene emissions less than 0.90 Mg/yr, and they must meet unit-specific BTEX emission limits. v. See sections VII and X of this preamble for further discussion of both standards.

3. Costs and Benefits

Table 1 summarizes the costs and benefits of this action. See section XI of this preamble for further discussion.

TABLE 1—SUMMARY OF THE MONETIZED BENEFITS, SOCIAL COSTS AND NET BENEFITS FOR THE FINAL OIL AND NATURAL GAS NSPS AND NESHAP AMENDMENTS IN 2015

[Millions of 2008$] [1]

	Final NSPS	Final NESHAP amendments	Final NSPS and NESHAP amendments combined
Total Monetized Benefits [2]	N/A	N/A	N/A.
Total Costs [3]	−$15 million	$3.5 million	−$11 million.
Net Benefits	N/A	N/A	N/A.
Non-monetized Benefits [4]	11,000 tons of HAP 190,000 tons of VOC 1.0 million tons of methane	670 tons of HAP 1,200 tons of VOC 420 tons of methane	12,000 tons of HAP. 190,000 tons of VOC. 1.0 million tons of methane.
	Health effects of HAP exposure. Health effects of $PM_{2.5}$ and ozone exposure. Visibility impairment. Vegetation effects. Climate effects.		

[1] All estimates are for the implementation year (2015).

[2] While we expect that these avoided emissions will result in improvements in air quality and reductions in health effects associated with HAP, ozone and particulate matter (PM), as well as climate effects associated with methane, we have determined that quantification of those benefits and co-benefits cannot be accomplished for this rule in a defensible way. This is not to imply that there are no benefits or co-benefits of the rules; rather, it is a reflection of the difficulties in modeling the direct and indirect impacts of the reductions in emissions for this industrial sector with the data currently available.

[3] The engineering compliance costs are annualized using a 7-percent discount rate. The negative cost for the final NSPS reflects the inclusion of revenues from additional natural gas and hydrocarbon condensate recovery that are estimated as a result of the NSPS. Possible explanations for why there appear to be negative cost control technologies are discussed in the engineering costs analysis section in the Regulatory Impact Analysis (RIA).

[4] For the NSPS, reduced exposure to HAP and climate effects are co-benefits. For the NESHAP, reduced VOC emissions, $PM_{2.5}$ and ozone exposure, visibility and vegetation effects and climate effects are co-benefits. The specific control technologies for the final NSPS are anticipated to have minor secondary disbenefits, including an increase of 1.1 million tons of carbon dioxide (CO_2), 550 tons of nitrogen oxides (NO_X), 19 tons of PM, 3,000 tons of carbon monoxide (CO) and 1,100 tons of total hydrocarbons (THC), as well as emission reductions associated with the energy system impacts. The specific control technologies for the NESHAP are anticipated to have minor secondary disbenefits, but the EPA was unable to estimate the secondary disbenefits. The net CO_2-equivalent emission reductions are 18 million metric tons.

B. Does this action apply to me?

The regulated categories and entities potentially affected by the final standards are shown in Table 2 of this preamble.

TABLE 2—INDUSTRIAL SOURCE CATEGORIES AFFECTED BY THIS ACTION

Category	NAICS code [1]	Examples of regulated entities
Industry	211111	Crude Petroleum and Natural Gas Extraction.
	211112	Natural Gas Liquid Extraction.
	221210	Natural Gas Distribution.
	486110	Pipeline Distribution of Crude Oil.
	486210	Pipeline Transportation of Natural Gas.
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 is meant to provide a guide for readers regarding entities likely to be affected by this action. If you have any questions regarding the applicability of this action to a particular entity, consult either the air permitting authority for the entity or your EPA regional representative as listed in 40 CFR 60.4 or 40 CFR 63.13 (General Provisions).

C. What are the emission sources affected by this action?

1. What are the emission sources affected by the NSPS?

The emission sources affected by the NSPS include well completions, pneumatic controllers, equipment leaks from natural gas processing plants, sweetening units at natural gas processing plants, reciprocating compressors, centrifugal compressors and storage vessels which are constructed, modified or reconstructed after August 23, 2011. Well completions subject to the NSPS are limited to the flowback period following hydraulic fracturing operations at a gas well affected facility. These completions include those conducted at newly drilled and fractured wells, as well as completions conducted following refracturing operations that may occur at various times over the life of the well. Pneumatic controllers affected by the NSPS include continuous bleed, natural gas-driven pneumatic controllers with a natural gas bleed rate greater than 6 scfh and which commenced construction after August 23, 2011, in the oil and natural gas production segment (except for gas processing plants) and continuous bleed natural gas-driven pneumatic controllers which commenced construction after August 23, 2011, at natural gas processing plants. The NSPS applies to centrifugal compressors with wet seals and reciprocating compressors located in the natural gas production and processing segments. The NSPS also applies to equipment leaks from onshore natural gas processing plants and to storage vessels located in the oil and natural gas production segment, the natural gas processing segment and the natural gas transmission and storage segment. The NSPS also affects sweetening units located onshore that process natural gas from onshore or offshore wells.

2. What are the emission sources affected by the NESHAP?

The emission sources that are affected by the Oil and Natural Gas Production NESHAP (40 CFR part 63, subpart HH) or the Natural Gas Transmission and Storage NESHAP (40 CFR part 63, subpart HHH) include glycol dehydrators and equipment leaks.

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

In addition to being available in the docket, an electronic copy of this action will also be available on the World Wide Web (WWW). Following signature by the Administrator, a copy of the action will be posted on the EPA's Web site at the following address: *http://www.epa.gov/airquality/oilandgas.*

Additional information is available on the EPA's RTR Web site at *http://www.epa.gov/ttn/vatw/rrisk/oarpg.html.* This information includes the most recent version of the rule, source category descriptions, detailed emissions and other data were used as inputs to the risk assessments.

E. Judicial Review

Under CAA section 307(b)(1), judicial review of this final rule is available only by filing a petition for review in the United States Court of Appeals for the District of Columbia Circuit by October 15, 2012. Under CAA section 307(d)(7)(B), only an objection to this final rule that was raised with reasonable specificity during the period for public comment (including any public hearing) can be raised during judicial review. This section also provides a mechanism for the EPA to convene a proceeding for reconsideration "[i]f the person raising an objection can demonstrate to the Administrator that it was impracticable

to raise such objection within [the period for public comment] or if the grounds for such objection arose after the period for public comment (but within the time specified for judicial review) and if such objection is of central relevance to the outcome of the rule[.]'' Any person seeking to make such a demonstration to us should submit a Petition for Reconsideration to the Office of the Administrator, Environmental Protection Agency, Room 3000, Ariel Rios Building, 1200 Pennsylvania Ave. NW., Washington, DC 20004, with a copy to the person listed in the preceding **FOR FURTHER INFORMATION CONTACT** section, and the Associate General Counsel for the Air and Radiation Law Office, Office of General Counsel (Mail Code 2344A), Environmental Protection Agency, 1200 Pennsylvania Ave. NW., Washington, DC 20004. Note, under CAA section 307(b)(2), the requirements established by this final rule may not be challenged separately in any civil or criminal proceedings brought by the EPA to enforce these requirements.

III. Background Information on the NSPS and NESHAP

A. What are the statutory authorities for the NSPS and NESHAP?

1. What is the statutory authority for the NSPS?

Section 111 of the CAA requires the EPA Administrator to list categories of stationary sources, if such sources cause or contribute significantly to air pollution, which may reasonably be anticipated to endanger public health or welfare. The EPA must then issue performance standards for such source categories. Whereas CAA section 112 standards are issued for new and existing stationary sources, standards of performance are issued for new and modified stationary sources. These standards are referred to as NSPS. The EPA has the authority to define the source categories, determine the pollutants for which standards should be developed, identify the facilities within each source category to be covered and set the emission level of the standards.

CAA section 111(b)(1)(B) requires the EPA to ''at least every 8 years review and, if appropriate, revise'' performance standards. However, the Administrator need not review any such standard if the ''Administrator determines that such review is not appropriate in light of readily available information on the efficacy'' of the standard. When conducting a review of an existing performance standard, the EPA has authority to revise that standard to add emission limits for pollutants or emission sources not currently regulated for that source category.

In setting or revising a performance standard, CAA section 111(a)(1) provides that performance standards are to ''reflect the degree of emission limitation achievable through the application of the BSER which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated.'' In this notice, we refer to this level of control as the BSER. In determining BSER, we typically conduct a technology review that identifies what emission reduction systems exist and how much they reduce air pollution, in practice. Next, for each control system identified, we evaluate its costs, secondary air benefits (or disbenefits) resulting from energy requirements and nonair quality impacts such as solid waste generation. Based on our evaluation, we would determine BSER. The resultant standard is usually a numerical emissions limit, expressed as a performance level (*i.e.,* a rate-based standard or percent control), that reflects the BSER. Although such standards are based on the BSER, the EPA may not prescribe a particular technology that must be used to comply with a performance standard, except in instances where the Administrator determines it is not feasible to prescribe or enforce a standard of performance. Typically, sources remain free to select any control measures that will meet the emission limits. Upon promulgation, an NSPS becomes a national standard to which all new sources must comply.

2. What is the statutory authority for the NESHAP?

Section 112 of the CAA establishes a two-stage regulatory process to address emissions of HAP from stationary sources. In the first stage, after the EPA has identified categories of sources emitting one or more of the HAP listed in section 112(b) of the CAA, section 112(d) of the CAA calls for us to promulgate NESHAP for those sources. ''Major sources'' are those that emit or have the potential to emit (PTE) 10 tpy or more of a single HAP or 25 tpy or more of any combination of HAP. For major sources, the technology-based emission standards must reflect the maximum degree of emission reductions of HAP achievable (after considering cost, energy requirements and nonair quality health and environmental impacts) and are commonly referred to as MACT standards.

MACT standards are set to reflect application of measures, processes, methods, systems or techniques, including, but not limited to, measures which, (1) reduce the volume of or eliminate pollutants through process changes, substitution of materials or other modifications, (2) enclose systems or processes to eliminate emissions, (3) capture or treat pollutants when released from a process, stack, storage or fugitive emissions point, (4) are design, equipment, work practice or operational standards (including requirements for operator training or certification) or (5) are a combination of the above. CAA sections 112(d)(2)(A)–(E). A MACT standard may take the form of a design, equipment, work practice or operational standard where the EPA first determines either that, (1) a pollutant cannot be emitted through a conveyance designed and constructed to emit or capture the pollutant or that any requirement for or use of such a conveyance would be inconsistent with law or (2) the application of measurement methodology to a particular class of sources is not practicable due to technological and economic limitations. CAA sections 112(h)(1),(2).

The MACT ''floor'' is the minimum control level allowed for MACT standards promulgated under CAA section 112(d)(3) and may not be based on cost considerations. For new sources, the MACT floor cannot be less stringent than the emission control that is achieved in practice by the best-controlled similar source. The MACT floors for existing sources can be less stringent than floors for new sources, but cannot be less stringent than the average emission limitation achieved by the best-performing 12 percent of existing sources in the category or subcategory (or the best-performing five sources for categories or subcategories with fewer than 30 sources). In developing MACT standards, we must also consider control options that are more stringent than the floor. We may establish standards more stringent than the floor based on the consideration of the cost of achieving the emissions reductions, any nonair quality health and environmental impacts and energy requirements.

The EPA is then required to review these technology-based standards and to revise them ''as necessary (taking into account developments in practices, processes, and control technologies)'' no less frequently than every 8 years, under CAA section 112(d)(6). In conducting this review, the EPA is not obliged to completely recalculate the prior MACT determination. *NRDC* v. *EPA,* 529 F.3d 1077, 1084 (D.C. Cir. 2008).

The second stage in standard-setting focuses on reducing any remaining ''residual'' risk according to CAA section 112(f). This provision requires, first, that the EPA prepare a Report to Congress discussing (among other things) methods of calculating risk posed (or potentially posed) by sources after implementation of the MACT standards, the public health significance of those risks and the EPA's recommendations as to legislation regarding such remaining risk. The EPA prepared and submitted this report (*Residual Risk Report to Congress,* EPA–453/R–99–001) in March 1999. Congress did not act in response to the report, thereby triggering the EPA's obligation under CAA section 112(f)(2) to analyze and address residual risk.

CAA section 112(f)(2) requires us to determine for source categories subject to MACT standards, whether the emissions standards provide an ample margin of safety to protect public health. CAA section 112(f)(2) expressly preserves our use of a two-step process for developing standards to address any residual risk and our interpretation of ''ample margin of safety'' developed in the *National Emission Standards for Hazardous Air Pollutants: Benzene Emissions from Maleic Anhydride Plants, Ethylbenzene/Styrene Plants, Benzene Storage Vessels, Benzene Equipment Leaks, and Coke By-Product Recovery Plants* (Benzene NESHAP) (54 FR 38044, September 14, 1989). The first step in this process is the determination of acceptable risk. The second step provides for an ample margin of safety to protect public health, which is the level at which the standards must be set (unless a more stringent standard is required to prevent an adverse environmental effect, taking into consideration costs, energy, safety and other relevant factors).

If the MACT standards for HAP that are ''classified as a known, probable, or possible human carcinogen do not reduce lifetime excess cancer risks to the individual most exposed to emissions from a source in the category or subcategory to less than 1-in-1 million,'' the EPA must promulgate residual risk standards for the source category (or subcategory), as necessary, to provide an ample margin of safety to protect public health. In doing so, the EPA may adopt standards equal to existing MACT standards if the EPA determines that the existing standards are sufficiently protective. *NRDC* v. *EPA,* 529 F.3d 1077, 1083 (D.C. Cir. 2008) (''If EPA determines that the existing technology-based standards provide an 'ample margin of safety,' then the Agency is free to readopt those standards during the residual risk rulemaking.''). As mentioned, the EPA must also adopt more stringent standards, if necessary, to prevent an adverse environmental effect,[1] but must consider cost, energy, safety and other relevant factors in doing so.

The terms ''individual most exposed,'' ''acceptable level,'' and ''ample margin of safety'' are not specifically defined in the CAA. However, CAA section 112(f)(2)(B) preserves the interpretation set out in the Benzene NESHAP, and the United States Court of Appeals for the District of Columbia Circuit has concluded that the EPA's interpretation of CAA section 112(f)(2) is a reasonable one. See *NRDC* v. *EPA,* 529 F.3d at 1083 (''[S]ubsection 112(f)(2)(B) expressly incorporates the EPA's interpretation of the Clean Air Act from the Benzene standard, complete with a citation to the **Federal Register**''). See, also, *A Legislative History of the Clean Air Act Amendments of 1990,* volume 1, p. 877 (Senate debate on Conference Report). We notified Congress in the *Residual Risk Report to Congress* that we intended to use the Benzene NESHAP approach in making CAA section 112(f) residual risk determinations (EPA–453/R–99–001, p. ES–11).

In the Benzene NESHAP, we stated as an overall objective:

> * * * in protecting public health with an ample margin of safety, we strive to provide maximum feasible protection against risks to health from hazardous air pollutants by, (1) protecting the greatest number of persons possible to an individual lifetime risk level no higher than approximately 1-in-1 million; and (2) limiting to no higher than approximately 1-in-10 thousand [*i.e.,* 100-in-1 million] the estimated risk that a person living near a facility would have if he or she were exposed to the maximum pollutant concentrations for 70 years.

The agency also stated in the *Residual Risk Report to Congress* that ''The EPA also considers incidence (the number of persons estimated to suffer cancer or other serious health effects as a result of exposure to a pollutant) to be an important measure of the health risk to the exposed population. Incidence measures the extent of health risk to the exposed population as a whole, by providing an estimate of the occurrence of cancer or other serious health effects in the exposed population.'' The agency went on to conclude that ''estimated incidence would be weighed along with other health risk information in judging acceptability.'' As explained more fully in our *Residual Risk Report to Congress,* the EPA does not define ''rigid line[s] of acceptability,'' but considers rather broad objectives to be weighed with a series of other health measures and factors (EPA–453/R–99–001, p. ES–11). The determination of what represents an ''acceptable'' risk is based on a judgment of ''what risks are acceptable in the world in which we live'' (*Residual Risk Report to Congress,* p. 178, quoting the Vinyl Chloride decision at 824 F.2d 1165) recognizing that our world is not risk-free.

In the Benzene NESHAP, we stated that ''EPA will generally presume that if the risk to [the maximum exposed] individual is no higher than approximately 1-in-10 thousand, that risk level is considered acceptable.'' 54 FR 38045. We discussed the maximum individual lifetime cancer risk (or maximum individual risk (MIR)) as being ''the estimated risk that a person living near a plant would have if he or she were exposed to the maximum pollutant concentrations for 70 years.'' *Id.* We explained that this measure of risk ''is an estimate of the upper bound of risk based on conservative assumptions, such as continuous exposure for 24 hours per day for 70 years.'' *Id.* We acknowledge that maximum individual lifetime cancer risk ''does not necessarily reflect the true risk, but displays a conservative risk level which is an upper-bound that is unlikely to be exceeded.'' *Id.* Understanding that there are both benefits and limitations to using maximum individual lifetime cancer risk as a metric for determining acceptability, we acknowledged in the 1989 Benzene NESHAP that ''consideration of maximum individual risk * * * must take into account the strengths and weaknesses of this measure of risk.'' *Id.* Consequently, the presumptive risk level of 100-in-1 million (1-in-10 thousand) provides a benchmark for judging the acceptability of maximum individual lifetime cancer risk, but does not constitute a rigid line for making that determination.

The agency also explained in the 1989 Benzene NESHAP the following: ''In establishing a presumption for MIR, rather than a rigid line for acceptability, the Agency intends to weigh it with a series of other health measures and factors. These include the overall incidence of cancer or other serious health effects within the exposed population, the numbers of persons exposed within each individual lifetime risk range and associated incidence within, typically, a 50-kilometer (km)

[1] ''Adverse environmental effect'' is defined in CAA section 112(a)(7) as any significant and widespread adverse effect, which may be reasonably anticipated to wildlife, aquatic life or natural resources, including adverse impacts on populations of endangered or threatened species or significant degradation of environmental qualities over broad areas.

exposure radius around facilities, the science policy assumptions and estimation uncertainties associated with the risk measures, weight of the scientific evidence for human health effects, other quantified or unquantified health effects, effects due to co-location of facilities and co-emission of pollutants.'' *Id.*

In some cases, these health measures and factors taken together may provide a more realistic description of the magnitude of risk in the exposed population than that provided by maximum individual lifetime cancer risk alone. As explained in the Benzene NESHAP, ''[e]ven though the risks judged 'acceptable' by the EPA in the first step of the Vinyl Chloride inquiry are already low, the second step of the inquiry, determining an 'ample margin of safety,' again includes consideration of all of the health factors, and whether to reduce the risks even further.'' In the ample margin of safety decision process, the agency again considers all of the health risks and other health information considered in the first step. Beyond that information, additional factors relating to the appropriate level are considered, including costs and economic impacts of controls, technological feasibility, uncertainties and any other relevant factors. Considering all of these factors, the agency will establish the standard at a level that provides an ample margin of safety to protect the public health, as required by CAA section 112(f). See 54 FR 38046.

B. What is the litigation history?

On January 14, 2009, pursuant to section 304(a)(2) of the CAA, WildEarth Guardians and the San Juan Citizens Alliance filed a complaint in the United States District Court for the District of Columbia and alleged that the EPA failed to meet its obligations under CAA sections 111(b)(1)(B), 112(d)(6) and 112(f)(2) to take actions relative to the review/revision of the NSPS and the NESHAP with respect to the Oil and Natural Gas Production source category. On February 5, 2010, the Court entered a consent decree that, as successively modified, required the EPA to sign by July 28, 2011,[2] proposed standards and/or determinations not to issue standards pursuant to CAA sections 111(b)(1)(B), 112(d)(6) and 112(f)(2) and to take final action by April 3, 2012. On April 2, 2012, the consent decree was modified to change the date for final action to no later than April 17, 2012.

C. What is the sector-based approach?

Sector-based approaches are based on integrated assessments of industrial operations that consider multiple pollutants in a comprehensive and coordinated manner to manage emissions and CAA requirements. One of the many ways we can address sector-based approaches is by reviewing multiple regulatory programs together whenever possible, for example the NSPS and NESHAP, consistent with all applicable legal requirements. This approach essentially expands the technical analyses on costs and benefits of particular technologies, to consider the interactions of rules that regulate sources. The benefit of multi-pollutant and sector-based analyses and approaches includes the ability to identify optimum strategies, considering feasibility, cost impacts and benefits across the different pollutant types while streamlining administrative and compliance complexities and reducing conflicting and redundant requirements, resulting in added certainty and easier implementation of control strategies for the sector under consideration. In order to benefit from a sector-based approach for the oil and gas industry, the EPA analyzed how the NSPS and NESHAP under consideration relate to each other and other regulatory requirements currently under review for oil and gas facilities. In this analysis, we looked at how the different control requirements that result from these requirements interact, including the different regulatory deadlines and control equipment requirements that result, the different reporting and recordkeeping requirements and opportunities for states to account for reductions resulting from this rulemaking in their State Implementation Plans (SIP). The requirements analyzed affect criteria pollutants, HAP and methane emissions from oil and natural gas processes and cover the NSPS and NESHAP reviews.

As a result of the sector-based approach, this rulemaking will reduce conflicting and redundant requirements. Also, the sector-based approach streamlines the monitoring, recordkeeping and reporting requirements, thus, reducing administrative and compliance complexities associated with complying with multiple regulations. In addition, the sector-based approach in this rule promotes a comprehensive control strategy that maximizes the co-control of multiple regulated pollutants while obtaining emission reductions as co-benefits.

D. What are the health effects of pollutants emitted from the oil and natural gas sector?

The final oil and natural gas sector NSPS and NESHAP amendments are expected to result in significant reductions in existing emissions and prevent new emissions from expansions of this industry. These emissions include HAP, VOC (a precursor to both $PM_{2.5}$ and ozone formation) and methane (a GHG and a precursor to global ozone formation). These emissions are associated with substantial health effects, welfare effects and climate effects. One HAP of particular concern from the oil and natural gas sector is benzene, which is a known human carcinogen. $PM_{2.5}$ is associated with health effects, including premature mortality for adults and infants, cardiovascular morbidity, such as heart attacks, hospital admissions and respiratory morbidity such as asthma attacks, acute and chronic bronchitis, hospital and emergency room visits, work loss days, restricted activity days and respiratory symptoms, as well as visibility impairment. Ozone is associated with health effects, including hospital and emergency department visits, school loss days and premature mortality, as well as injury to vegetation and climate effects.

IV. Summary of the Final NSPS Rule

A. What are the final actions relative to the NSPS for the Crude Oil and Natural Gas Production source category?

We are revising the existing NSPS, which regulate VOC emissions from equipment leaks and SO_2 emissions from sweetening units at onshore gas processing plants. In addition, we are promulgating standards for several new oil and natural gas affected facilities. The final standards apply to affected facilities that commence construction, reconstruction or modification after August 23, 2011, the date of the proposed rule.

The listed Crude Oil and Natural Gas Production source category covers, at a minimum, those operations for which we are establishing standards in this final rule. Table 3 summarizes the 40 CFR part 60, subpart OOOO standards. Further discussion of these changes may

[2] On April 27, 2011, pursuant to paragraph 10(a) of the Consent Decree, the parties filed with the Court a written stipulation to extend the proposal date from January 31, 2011, to July 28, 2011, and the final action date from November 30, 2011, to February 28, 2012. On October 28, 2011, pursuant to paragraph 10(a) of the Consent Decree, the parties filed with the Court a written stipulation to extend the final action date from February 28, 2012, to April 3, 2012.

be found below in this section and in sections V and IX of this preamble.

TABLE 3—SUMMARY OF 40 CFR PART 60, SUBPART OOOO EMISSION STANDARDS

Affected facility	Pollutant	Standard	Compliance dates
Hydraulically fractured wildcat and delineation wells.	VOC	Route flowback emissions to completion combustion device.	October 15, 2012.
Hydraulically fractured low pressure wells, non-wildcat and non-delineation wells.	VOC	Route flowback emissions to completion combustion device.	October 15, 2012.
All other hydraulically fractured gas wells	VOC	Route flowback emissions to completion combustion device.	Prior to January 1, 2015.
All other hydraulically fractured gas wells	VOC	Use REC and route flowback emissions to completion combustion device.	On or after January 1, 2015.
Centrifugal compressors with wet seals	VOC	Reduce emissions by 95 percent	October 15, 2012.
Reciprocating compressors	VOC	Change rod packing after 26,000 hours or after 36 months.	October 15, 2012.
Continuous bleed natural gas-driven pneumatic controllers at natural gas processing plants.	VOC	Natural gas bleed rate of zero	October 15, 2012.
Continuous bleed natural gas-driven pneumatic controllers with a bleed rate greater than 6 scfh between wellhead and natural gas processing plant or oil pipeline.	VOC	Natural gas bleed rate less than 6 scfh	October 15, 2013.
Storage vessels with VOC emissions equal to or greater than 6 tpy.	VOC	Reduce emissions by 95 percent	October 15, 2013.
Equipment leaks at onshore natural gas processing plants.	VOC	LDAR program	October 15, 2012.
Sweetening units at onshore natural gas processing plants.	SO_2	Reduce SO_2 emissions based on sulfur feed rate and sulfur content of acid gas.	October 15, 2012.

1. Standards for Gas Well Affected Facilities

We are finalizing operational standards for completions of hydraulically fractured and refractured gas wells. For purposes of this rule, well completion is defined as the flowback period beginning after hydraulic fracturing and ending with either well shut in or when the well continuously flows to the flow line or to a storage vessel for collection, whichever occurs first. The final rule applies to three subcategories of fractured and refractured gas wells for which well completion operations are conducted: (1) Wildcat (exploratory) and delineation gas wells; (2) non-wildcat and non-delineation gas wells for which the reservoir pressure is insufficient for a REC, commonly referred to as a ''green completion,'' to be performed, as determined by a simple calculation involving reservoir pressure, well depth and flow line pressure at the sales meter (we refer to these wells as ''low pressure gas wells'') and (3) other fractured and refractured gas wells. For subcategory (3) wells, each well completion operation begun on or after January 1, 2015, must employ REC in combination with use of a completion combustion device to control gas not suitable for entering the flow line (we refer to this as REC with combustion). For well completion operations at subcategory (1) wells (exploratory and delineation gas wells), subcategory (2) wells (low pressure gas wells) and for well completion operations begun prior to January 1, 2015, at subcategory (3) gas wells, the final rule requires the control of emissions using either REC with combustion or just a completion combustion device. Owners and operators are encouraged to use REC with combustion during this period.

Well completions subject to the standards are gas well completions following hydraulic fracturing and refracturing operations. These completions include those conducted at newly drilled and fractured wells, as well as completions conducted following refracturing operations at various times over the life of the well. As we explained in the proposal preamble, a completion operation associated with refracturing performed at a well is considered a modification under CAA section 111(a), because physical change occurs to the well resulting in emissions increases during the refracturing and completion operation. In response to comment, we further clarify this point in the final rule, including providing a specific modification provision for well completions in lieu of the General Provisions in 40 CFR 60.14. For a more detailed explanation, please see section IX.A of this preamble. The modification determination and resulting applicability of NSPS to the completion operation following refracturing of gas wells is limited strictly to the gas well affected facility and does not by itself trigger applicability beyond the wellhead to other ancillary components that may be at the well site such as existing storage vessels, process vessels, separators, dehydrators or any other components or apparatus (that is, such equipment is not part of the affected facility).

The final rule provides that uncontrolled well completions conducted on gas wells that are subsequently refractured on or after the effective date of this rule are modifications and are subject to the NSPS. However, gas wells that undergo completion following refracturing are not considered modified and, as a result, are not affected facilities under the NSPS if the completion operation is conducted with the use, immediately upon flowback, of emission control techniques otherwise required on or after January 1, 2015, for new wells and satisfies other requirements, including notification, recordkeeping and reporting requirements.

In the final rule, we provide for a streamlined notification process for well completions at gas well affected facilities consisting of an email pre-notification no later than 2 days in advance of impending completion operations. The email must include information that had been part of the 30-day advance notification, as described in the proposed rule, including contact information for the owner and operator, well identification, geographic

coordinates of the well and planned date of the beginning of flowback.

In the final rule, the recordkeeping and reporting requirements for well completions also provide for a streamlining option that owners and operators may choose in lieu of the standard annual reporting requirements. The standard annual report must include copies of all well completion records for each gas well affected facility for which a completion operation was performed during the reporting period. The alternative, streamlined annual report for gas well affected facilities requires submission of a list, with identifying information of all affected gas wells completed, electronic or hard copy photographs documenting REC in progress for each well for which REC was required and the self-certification required in the standard annual report. The operator retains a digital image of each REC in progress. The image must include a digital date stamp and geographic coordinates stamp to help link the photograph with the specific well completion operation.

2. Standards for Compressor Affected Facilities

The final rule requires measures to reduce VOC emissions from centrifugal and reciprocating compressors. Compressors located at the wellhead or in the transmission, storage and distribution segments are not covered by this final rule and, therefore, are not affected facilities. The final rule contains standards for wet seal centrifugal compressors located in the natural gas production segment and the natural gas processing segment up the point at which the gas enters the transmission and storage segment. The final standards require 95.0 percent reduction of the emissions from each wet seal centrifugal compressor affected facility. The standard can be achieved by capturing and routing the emissions to a control device that achieves an emission reduction of 95.0 percent.

The operational standards for reciprocating compressors in the final rule require replacement of the rod packing based on usage. The owner or operator of a reciprocating compressor affected facility is required to change the rod packing immediately when hours of operation reach 26,000 hours (equivalent to 36 months of continuous usage). Alternatively, owners or operators can elect to change the rod packing every 36 months in lieu of monitoring compressor operating hours. An owner or operator who elects to meet the 26,000 hour requirement is required to monitor the duration (in hours) that the compressor is operated, beginning on the date of initial startup of the reciprocating compressor affected facility, or on the date of the previous rod packing replacement, whichever is later.

3. Standards for Pneumatic Controller Affected Facilities

We are also finalizing pneumatic controller VOC standards. The affected facility is a continuous bleed, natural gas-driven pneumatic controller with a natural gas bleed rate greater than 6 scfh for which construction commenced after August 23, 2011, located (1) in the oil production segment between the wellhead and the point of custody transfer to an oil pipeline; or (2) in the natural gas production segment, excluding natural gas processing plants, between the wellhead and the point at which the gas enters the transmission and storage segment. Except for controllers located at natural gas processing plants, each continuous bleed, natural gas-driven pneumatic controller that emits more than 6 scfh is an affected facility if it is constructed or modified after August 23, 2011. Pneumatic controllers with a bleed rate of 6 scfh or less in the oil and natural gas production segment and all pneumatic controllers located in the natural gas transmission, storage and distribution segments are not covered by this final rule and, therefore, are not affected facilities. At natural gas processing plants, the affected facility is each individual continuous bleed natural gas-operated pneumatic controller, and the final rule includes a natural gas bleed rate limit of zero scfh. The final emission standards for pneumatic controllers at natural gas processing plants reflect the emission level achievable from the use of non-natural gas-driven pneumatic controllers. At other locations in the oil and natural gas production segment, the final rule includes a natural gas bleed rate limit of 6 standard cubic feet of gas per hour for an individual pneumatic controller. The standards provide exemptions in cases where it has been demonstrated that the use of a natural gas-driven pneumatic controller with a bleed rate above the applicable standard is required. However, as discussed in section IX.C, the EPA is allowing a 1-year phase-in period for pneumatic controllers in the final rule.

4. Standards for Storage Vessels

The final rule contains VOC standards for new, modified or reconstructed storage vessels located in the oil and natural gas production, natural gas processing and natural gas transmission and storage segments. The final rule, which applies to individual storage vessels, requires that storage vessels with VOC emissions equal to or greater than 6 tpy achieve at least 95.0 percent reduction in VOC emissions. For storage vessels constructed, modified or reconstructed at well sites with no wells already in production at the time of construction, modification or reconstruction, the final rule provides a 30-day period from startup for the owner or operator to determine whether the magnitude of VOC emissions from the storage vessel will be at least 6 tpy. If the storage vessel requires control, the final rule provides an additional 30 days for the control device to be installed and operational. For storage vessels constructed, modified or reconstructed at well sites with one or more wells already in production at the time of construction, modification or reconstruction, these estimation and installation periods are not provided because an estimate of VOC emissions can be made using information on the liquid production characteristics of the existing wells.

In addition, the final rule provides for a 1-year phase-in period for storage vessel controls. Refer to section IX.E.4 of this preamble for further discussion.

5. Standards for Affected Facilities Located at Onshore Natural Gas Processing Plants

For onshore natural gas processing plants, we are revising the existing NSPS requirements for LDAR to reflect the procedures and leak thresholds established by 40 CFR part 60, subpart VVa. Subpart VVa lowers the leak definition for valves from 10,000 ppm to 500 ppm, and requires the monitoring of connectors. Pumps, pressure relief devices and open-ended valves or lines are also monitored.

6. Standards for Sweetening Unit Affected Facilities at Onshore Natural Gas Processing Plants

The final rule regulates SO_2 emissions from natural gas processing plants by requiring affected facilities to reduce SO_2 emissions by recovering sulfur. The final rule incorporates the provisions of 40 CFR part 60, subpart LLL into 40 CFR part 60, subpart OOOO, and minor revisions were made to adapt the subpart LLL language to subpart OOOO. The final rule also increased the SO_2 emission reduction standard from the subpart LLL requirement of 99.8 percent to 99.9 percent for units with sulfur production rate of at least 5 long tons per day. This change is based on reanalysis of the original data used in the subpart LLL BSER analysis.

B. What are the effective and compliance dates for the final NSPS?

The revisions to the existing NSPS standards and the new NSPS standards promulgated in this action are effective on October 15, 2012. Affected facilities must be in compliance with the final standards on the effective date, October 15, 2012.

V. Summary of the Significant Changes to the NSPS Since Proposal

The previous section summarized the requirements that the EPA is finalizing in this rule. This section will discuss in greater detail the key changes the EPA has made since proposal. These changes result from the EPA's review of the additional data and information provided to us and our consideration of the many substantive and thoughtful comments submitted on the proposal.

We believe the changes make the final rule more flexible and cost-effective, address concerns with equipment availability, streamline recordkeeping and reporting requirements and improve clarity, while fully preserving or improving the public health and environmental protection required by the CAA.

A. Gas Well Affected Facilities

We have revised the requirements for gas well affected facilities since proposal in response to comment. The final rule applies to three subcategories of fractured and refractured gas wells for which well completion operations are conducted: (1) Wildcat (exploratory) and delineation gas wells; (2) non-wildcat and non-delineation gas wells for which the reservoir pressure is insufficient for a REC to be performed, as determined by a simple calculation involving reservoir pressure, well depth and flow line pressure at the sales meter (we refer to these wells as "low pressure gas wells"); and (3) other fractured and refractured gas wells. In the proposed 40 CFR part 60, subpart OOOO, upon promulgation of this rule, each well completion or recompletion at a non-exploratory or non-delineation well would have had to employ REC with combustion. Because of uncertainties in the supply of equipment and labor over the near-term, we are now requiring this work practice standard for completion operations begun at subcategory (3) gas wells (non-exploratory and non-delineation wells) on or after January 1, 2015. Until this date, flowback emissions must either be controlled using REC or routed to a completion combustion device unless it is technically infeasible or unsafe to do so. Owners and operators are encouraged to use REC when available during this period. Completion operations at subcategory (1) gas wells (wildcat and delineation wells) and subcategory (2) gas wells (non-wildcat and non-delineation low pressure gas wells) begun on or after October 15, 2012 are required to control flowback emissions by using REC with combustion or by routing emissions to a completion combustion device alone unless it is technically infeasible or unsafe to do so.

The final rule includes a specific modification provision for well completions in lieu of the General Provisions in 40 CFR 60.14. For a more detailed explanation, please see section IX.A of this preamble. In addition, we have revised the definition of "flowback period" to more clearly define when the flowback period begins and ends.

In the proposed rule, all completions at existing wells (*i.e.,* those originally constructed on or before August 23, 2011) that are subsequently fractured or refractured were considered to be modifications. In the final rule, completions of wells that are refractured on or after the rule's effective date are not considered modified and, as a result, are not affected facilities under the NSPS, if the completion operation is conducted with the use, immediately upon flowback, of emission control techniques required on or after January 1, 2015, for new wells and satisfies other requirements, including notification, recordkeeping and reporting requirements.

In the proposed rule, we prescribed specific equipment to accomplish an REC. In the final rule, we have removed the required equipment specifications for REC and added operational standards that will result in minimizing emissions and maximizing product recovery. In light of the comments received, we conclude that it is inappropriate and unnecessary to prohibit the use of other equipment that can be used to accomplish an REC and that the operational standards can be achieved using a variety of equipment that can change from well to well.

Initial compliance requirements for gas well affected facilities have also been revised and streamlined. Owners and operators are now required to notify the Administrator of the actual date of each well completion operation by email no later than 2 days prior to the well completion operation, rather than the proposed requirement of notifying the Administrator of the date of the well completion operation within 30 days of the commencement of each well completion operation. The email must include information that had been part of the 30-day advance notification, as described in the proposed rule, including contact information for the owner and operator, well identification, geographic coordinates of the well and planned date of the beginning of flowback. However, if the owner or operator is subject to state regulations that require advance notification of well completions and has met those advance notification requirements, then the owner or operator is considered to have met the advance notification requirements for gas well completions under the NSPS.

In the final rule, the recordkeeping and reporting requirements for well completions also provide for a streamlining option that owners and operators may choose in lieu of the standard annual reporting requirements. The standard annual report must include copies of all well completion records for each gas well affected facility for which a completion operation was performed during the reporting period. The alternative, streamlined annual report for gas well affected facilities requires submission of a list, with identifying information of all affected gas wells completed, electronic or hard copy photographs documenting REC in progress for each well for which REC was required and the self-certification required in the standard annual report. The operator retains a digital image of each REC in progress. The image must include a digital date stamp and geographic coordinates stamp to help link the photograph with the specific well completion operation.

Refer to section IX.B of this preamble and the Responses to Comments document, available in the docket, for detailed discussion regarding these changes.

B. Centrifugal and Reciprocating Compressor Affected Facilities

In the final rule, we have made changes that impact both reciprocating and centrifugal compressor affected facilities in response to comments requesting clarification. Because we are not finalizing standards covering them, centrifugal and reciprocating compressors located in the transmission, storage and distribution segments are not affected facilities.

In the proposed rule, all centrifugal compressors would be required to use dry seals. We had also solicited comment on the use of wet seals with controls as an acceptable alternative to dry seals due to potential technical infeasibility of using dry seals for certain applications. Based on comments received, the final rule requires that centrifugal compressors with wet seals reduce emissions by 95.0

percent. The standard can be achieved by capturing and routing emissions from the wet seal fluid degassing system to a control device that reduces VOC emissions by 95.0 percent. Testing, monitoring, recordkeeping, reporting and notification requirements associated with the control devices have also been added. In contrast to the proposed rule, in the final rule, centrifugal compressors with dry seals are not affected facilities. More detailed discussion of this change is presented in section IX.D of this preamble.

As proposed, owners or operators of reciprocating compressor affected facilities were required to change rod packing after 26,000 hours of operation. This is equivalent to approximately 36 months of continuous operation. Based on comments we received, we are changing the final rule to provide operators the option of changing the rod packing every 36 months instead of tracking compressor hours of operation and changing rod packing after 26,000 hours of operation.

Refer to section IX.D of this preamble and the Responses to Comments document, available in the docket, for detailed discussion regarding these changes.

C. Pneumatic Controller Affected Facilities

For pneumatic controller affected facilities located in the oil and natural gas production segments, we have revised the definition of pneumatic controller affected facility from a single pneumatic controller to a single, continuous bleed, natural gas-driven pneumatic controller with a continuous bleed rate greater than 6 scfh for which construction, modification or reconstruction commenced after August 23, 2011. At natural gas processing plants, individual continuous bleed natural gas-operated pneumatic controllers for which construction, modification or reconstruction commenced after August 23, 2011, are affected facilities under this rule. As explained further in section IX.C of this preamble, this change provides clarity by more specifically defining the pneumatic controllers we intended to regulate in this final rule. In addition, only pneumatic controllers located prior to the point at which the gas enters the transmission and storage segment are subject to the NSPS. Because we are not finalizing standards covering them, controllers located in the transmission and storage segment are not affected facilities. The emission rates we proposed for pneumatic controllers have not changed in the final rule.

All new pneumatic controller affected facilities are required, in the final rule, to be tagged with the month and year of installation and identification that allows traceability to the records for that controller.

In the proposed rule, each pneumatic controller affected facility would have to comply upon promulgation. The final rule allows a 1-year phase-in beginning October 15, 2012 before the bleed rate limit is effective for an affected facility. We believe this is necessary for at least two reasons. First, owners and operators would demonstrate compliance based on information in the manufacturers' specification. We have concluded that such information is not always included in current manufacturers' specifications and a period of time is required for manufacturers to test their products and modify specifications to include the information. Second, we are not aware of any add-on control device that is or can be used to reduce VOC emissions from gas-driven pneumatic devices.

Finally, language in the proposed rule could have been interpreted to mean that all pneumatic controllers installed in any year after the proposal date must be reported each year, rather than those installed only during the reporting period. In order to clarify and streamline the recordkeeping and reporting requirements associated with pneumatic controllers, we are requiring only information concerning those affected facilities constructed, modified or reconstructed during the reporting period to be included in the annual report.

Refer to section IX.C of this preamble and the Responses to Comments document, available in the docket, for detailed discussion regarding these changes.

D. Storage Vessel Affected Facilities

We have modified the definition of "storage vessel" to exclude surge control vessels, knockout vessels and pressure vessels designed to operate without emissions to the atmosphere. In addition, we have clarified that we consider a storage vessel that is skid-mounted or permanently attached to something that is mobile (such as trucks, railcars, barges or ships) to be subject to 40 CFR part 60, subpart OOOO if it is intended to be located at a site for at least 180 consecutive days.

In the proposed rule, we established a throughput threshold for storage vessels below which they were not subject to the NSPS. In order to remove confusion with respect to the emission factors used to develop the throughput threshold and to address comments indicating significant difficulty measuring throughput, we have revised the final rule such that storage vessels that emit 6 tpy of VOC or more are subject to the NSPS, based on our analysis in the proposed rule showing that the proposed NSPS is cost-effective for storage vessels with that level of VOC emissions. In the final rule, for storage vessels constructed, modified or reconstructed at well sites with no wells already in production at the time of construction, the final rule provides a 30-day period for the owner or operator to determine whether the magnitude of VOC emissions from the storage vessel will be at least 6 tpy. If the storage vessel requires control, the final rule provides an additional 30 days for the control device to be installed and operational. For storage vessels constructed, modified or reconstructed at well sites with one or more wells already in production at the time of construction, modification or reconstruction, VOC emissions can be determined prior to startup. Accordingly, these estimation and installation periods are not necessary and, therefore, not provided.

Several requirements for storage vessels in the proposed rule pointed to 40 CFR part 63, subpart HH (the Oil and Natural Gas Production NESHAP). However, subpart HH regulates HAP while this NSPS regulates VOC. Therefore, in order to eliminate confusion caused by cross-referencing another regulation and to tailor the requirements for VOC regulation, we have incorporated the storage vessel requirements from subpart HH into 40 CFR part 60, subpart OOOO and modified those requirements, as appropriate for this rule.

In the proposed rule, each storage vessel required to reduce emissions would have to comply upon promulgation. In the final rule, owners or operators are allowed a 1-year phase-in beginning October 15, 2012 before the 95.0-percent control requirement is effective. We believe this is necessary because of initial problems securing control devices that are manufacturer-tested and have appropriate documentation for determining control efficiency. In addition, we believe that owners or operators will require a period of time to establish the need for controls and install them where called for. The 1-year phase-in will also allow owners or operators the necessary time to establish the need for a control device and procure and install the equipment.

Refer to section IX.E of this preamble and the Responses to Comments document, available in the docket, for detailed discussion regarding these changes.

E. Equipment Leaks Affected Facilities and Sweetening Unit Affected Facilities at Onshore Natural Gas Processing Plants

We have revised the identification of affected facilities for equipment leaks at natural gas processing plants. We proposed that compressors and equipment (as defined in the rule) located at onshore natural gas processing plants were affected facilities. As discussed above, compressors (reciprocating and centrifugal) have requirements under 40 CFR part 60, subpart OOOO that extend beyond the natural gas processing plant. To remove the duplicative requirements for compressors at natural gas processing plants, we have revised the identification of affected facility to exclude compressors from the standards that apply to equipment leaks at onshore natural gas processing plants. Refer to the Responses to Comments document, available in the docket, for detailed discussion regarding these affected facilities.

F. Changes to Notification, Recordkeeping and Reporting Requirements

In response to comment expressing concern with the burdens associated with demonstrating and monitoring compliance, we have reanalyzed the notification, recordkeeping and reporting requirements in the proposed rule and eliminated duplicative and unnecessary requirements for all emission points. For well completions, compressors, pneumatic controllers and storage vessels, we have removed the General Provisions notification requirements in 40 CFR 60.7(a)(1), (3) and (4). These requirements relate to notification of construction and initial performance testing and are more suited to construction of more traditional facilities (*e.g.,* gas processing plants, refineries and chemical plants) than the numerous individual pieces of apparatus (*e.g.,* individual pneumatic controllers, compressor and storage vessels) that are ''affected facilities'' under this final rule. Specific notification and initial compliance demonstration requirements in the final rule make the General Provisions notification requirements unnecessary for gas well affected facilities.

As mentioned previously, we have also streamlined the notification, recordkeeping and reporting requirements for gas well affected facilities. In place of a written notification of each well completion operation 30 days prior to the completion, owners or operators must submit a notification no later than 2 days prior to the date of the completion. This notification may be submitted by email. To avoid duplicative and potentially conflicting advance notification requirements, the final rule provides that owners or operators who are subject to state regulations that require advance notification of well completions and have met those notification requirements are considered to have met the advance notification requirements of the NSPS. Additionally, in lieu of the standard annual reporting requirements, the final rule allows submission of an annual report for gas well affected facilities that consists only of a list, with identifying information of all affected gas wells completed, electronic or hard copy photographs documenting REC in progress for each well for which REC was required and the self-certification required in the standard annual report.

In the affirmative defense provisions of the rule, a citation was corrected, minor wording changes were made and reporting requirements were refined. The provisions we retained in the final rule are those we believe are necessary to assure regulatory agencies and the public that the owner or operator is in compliance with the final rule. Refer to section IX.F of this preamble and the Responses to Comments document, available in the docket, for detailed discussion regarding these changes.

VI. Summary of the Final NESHAP Rules

A. What are the final rule actions relative to the Oil and Natural Gas Production (subpart HH) source category?

Table 4 summarizes the changes to 40 CFR part 63, subpart HH. Further discussion of these changes may be found below in this section and in sections VII and X of this preamble.

TABLE 4—SUMMARY OF CHANGES TO 40 CFR PART 63, SUBPART HH

Affected source	Nature of change	Standard
Small glycol dehydrators	Established MACT standards for previously unregulated source.	BTEX emission limit: New sources—4.66×10^{-6} g/scm-ppmv. Existing sources—3.28×10^{-4} g/scm-ppmv.
''Associated equipment''	Revised definition to exclude all storage vessels	N/A.
Valves—equipment leaks	Revised definition of leak	LDAR for valves must be applied at 500 ppm.
All affected sources	Eliminated exemption from compliance during periods of startup, shutdown and malfunction.	Standards apply at all times.

Pursuant to CAA sections 112(d)(2) and (3), we have established MACT standards for small glycol dehydrators that were not regulated in the initial NESHAP. In addition, we have revised the definition of ''associated equipment'' to exclude from the definition of that term all storage vessels, not just those with potential for flash emissions (PFE).

With regard to our CAA section 112(d)(6) review, we conclude that there have been no developments in practices, processes or control technologies for large glycol dehydrators and storage vessels with PFE. As noted at proposal, however, there have been relevant developments for equipment leaks, and we are finalizing the proposed revisions to the leak definition for valves at natural gas processing plants. Specifically, under CAA section 112(d)(6), we revised the leak definition for valves to 500 ppm, thus requiring the application of the leak detection and repair requirement at this lower detection level. We did not make other revisions to the standards pursuant to our CAA section 112(d)(6) review. Our review under CAA section 112(f)(2) also did not result in revision to the standards. We found that the MACT standards in 40 CFR part 63, subpart HH (coupled with the new MACT standard for small glycol dehydrators) provide an ample margin of safety to protect public health and prevent adverse environmental effects. Accordingly, we are re-adopting those standards to satisfy the requirements of CAA section 112(f).

Additionally, we amended 40 CFR part 63, subpart HH to apply the standards at all times and made other revisions relative to periods of startup,

shutdown and malfunction. Lastly, the final rule revises and adds certain testing and monitoring and related notification, recordkeeping and reporting requirements and makes certain other minor technical revisions to the NESHAP.

1. Standards for Small Glycol Dehydration Units

In this final rule, we have established MACT standards under CAA sections 112(d)(2) and (3) for small glycol dehydration units, which were left unregulated in the initial NESHAP. This subcategory consists of glycol dehydrators with an actual annual average natural gas flowrate less than 85,000 standard cubic meters per day (scmd) or actual average benzene emissions less than 0.9 megagrams per year (Mg/yr). The final MACT standards for small dehydrators at oil and gas production facilities require that existing affected sources at a major source meet a unit-specific BTEX limit of 3.28×10^{-4} grams BTEX/standard cubic meters (scm)-parts per million by volume (ppmv) and that new affected sources meet a BTEX limit of 4.66×10^{-6} grams BTEX/scm-ppmv.

2. Standards for Equipment Leaks

In the final rule, as a result of our technology review under CAA section 112(d)(6), we are revising the leak definition for valves to 500 ppm, thus requiring the application of the LDAR requirement at this lower detection level. This leak definition applies only to valves at natural gas processing plants, and not other components.

3. Notification, Recordkeeping and Reporting Requirements

The final rule revises certain recordkeeping requirements of 40 CFR part 63, subpart HH. Specifically, facilities using carbon adsorbers as a control device are required to keep records of their carbon replacement schedule and records for each carbon replacement. In addition, owners and operators are required to keep records of the occurrence and duration of each malfunction of operation (*i.e.,* process equipment) or the air pollution control equipment and monitoring equipment.

In conjunction with the new MACT standards for small existing glycol dehydration units, owners and operators of such affected units are required to submit an initial notification within 1 year after they become subject to the provisions of this subpart or by October 15, 2013, whichever is later.

The final amendments to the NESHAP also include additional requirements for the contents of the periodic reports. The periodic reports are required to include periodic test results and information regarding any carbon replacement events that occurred during the reporting period. Additionally, periodic reports are required to include the number, duration, and a brief description for each type of malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded. The periodic report is also required to include a description of actions taken by an owner or operator during a malfunction of an affected source to minimize emissions, including actions taken to correct a malfunction.

B. What are the final rule amendments for the Natural Gas Transmission and Storage (subpart HHH) source category?

Table 5 summarizes the changes to 40 CFR part 63, subpart HHH. Further discussion of these changes may be found below in this section and in sections VII and X of this preamble.

TABLE 5—SUMMARY OF CHANGES TO 40 CFR PART 63, SUBPART HHH

Affected source	Nature of change	Standard
Small glycol dehydrators	Established MACT standards for previously unregulated source.	BTEX emission limit: New sources—5.44×10^{-5} g/scm-ppmv. Existing sources—3.01×10^{-4} g/scm-ppmv.
All affected sources	Eliminated exemption from compliance during periods of startup, shutdown and malfunction.	Standards apply at all times.

Pursuant to CAA section 112(d)(2) and (3), we have established MACT standards for small glycol dehydrators that were not regulated in the initial NESHAP. We have also amended 40 CFR part 63, subpart HHH to apply the standards at all times, and made other revisions relative to periods of startup, shutdown and malfunction. Lastly, the final rule revises and adds certain testing and monitoring and related notification, recordkeeping and reporting requirements, as well as makes other minor technical revisions to the NESHAP.

With regard to our CAA section 112(d)(6) review, we conclude that there have been no developments in practices processes or control technologies for large glycol dehydrators. We also found that the MACT standards in 40 CFR part 63, subpart HHH (coupled with the new MACT standard for small glycol dehydrators) provide an ample margin of safety to protect public health and prevent adverse environmental effects. Accordingly, we are re-adopting those standards to satisfy the requirements of CAA section 112(f). Thus, our reviews under CAA sections 112(d)(6) and 112(f)(2) did not result in any revisions to the standards.

1. Standards for Glycol Dehydration Units

In this final rule, we have established MACT standards for small glycol dehydration units in the Natural Gas Transmission and Storage source category. This subcategory consists of glycol dehydrators with an actual annual average natural gas flowrate less than 283,000 scmd or actual average benzene emissions less than 0.9 Mg/yr. The final MACT standard for this subcategory of small dehydrators requires existing affected sources to meet a unit-specific BTEX emission limit of 3.01×10^{-4} grams BTEX/scm-ppmv and new affected sources are required to meet a BTEX limit of 5.44×10^{-5} grams BTEX/scm-ppmv.

2. Notification, Recordkeeping and Reporting Requirements

The final rule revises certain recordkeeping requirements of 40 CFR part 63, subpart HHH. Specifically, facilities using carbon adsorbers as a control device are required to keep records of their carbon replacement schedule and records for each carbon replacement. In addition, owners and operators are required to keep records of the occurrence and duration of each malfunction of operation (*i.e.,* process equipment) or the air pollution control equipment and monitoring equipment.

In conjunction with the promulgation of the MACT standards for small glycol dehydration units, the final rule requires that owners and operators of such affected units submit an initial notification within 1 year after the unit becomes subject to the provisions of this

subpart or by October 15, 2013, whichever is later.

The final amendments to the NESHAP also include additional requirements for the contents of the periodic reports. For 40 CFR part 63, subpart HHH, the periodic reports are required to include periodic test results and information regarding any carbon replacement events that occurred during the reporting period. Additionally, periodic reports are required to include the number, duration, and a brief description for each type of malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded. The periodic report is also required to include a description of actions taken by an owner or operator during a malfunction of an affected source to minimize emissions, including actions taken to correct a malfunction.

C. What is the effective date of this final rule and compliance dates for the standards?

The effective date of this rule is October 15, 2012.

The compliance date for new affected sources (those that commenced construction or reconstruction on or after August 23, 2011) is immediately upon initial startup or the effective date of the standards, October 15, 2012, whichever is later.

The compliance date for existing small glycol dehydration units that are subject to MACT for the first time (*i.e.*, those that commenced construction before August 23, 2011) is October 15, 2015.

An affected source at a production field facility that constructed before August 23, 2011, that was previously determined to be an area source but becomes a major source on October 15, 2012 due to the amendment to the associated equipment definition in 40 CFR part 63, subpart HH, has until October 15, 2015 to comply with the relevant emission standards.

The compliance date for valves at existing natural gas processing plants, constructed before August 23, 2011, due to the amendment to the leak definition in 40 CFR part 63, subpart HH, is 1 year after the effective date of the standards October 15, 2013.

VII. Summary of the Significant Changes to the NESHAP Since Proposal

The previous section described the requirements that the EPA is finalizing in this rule. This section discusses in greater detail the key changes the EPA is making from the proposal. These changes result from the EPA's review of the additional data and information provided to us and our consideration of the substantive comments submitted on the proposal.

We have retained the same approach and methodology to establishing the standards as described at proposal. We have, however, made some changes in response to comments, which are described further below. One change resulted in revisions to the MACT emission limits for small glycol dehydration units. In addition, based on the comments received, we are not finalizing the MACT standard for the subcategory of storage vessels without the PFE, which was a subcategory that was left unregulated in the 1999 40 CFR part 63, subpart HH rule. Specifically, based on our review of the comments, we believe that we need additional data and information to set an emission standard for storage vessels without the PFE, and we intend to collect the additional data and propose MACT emission standards under section 112(d)(2) and (3) of the CAA for such storage vessels. Finally, we are retaining the 0.9 Mg/yr compliance option for large dehydration units.

A. What are the significant changes since proposal for the Oil and Natural Gas Production (subpart HH) source category?

1. Changes Made to Amendments Proposed Under the Authority of CAA Sections 112(d)(2) and (3)

Under the authority of sections 112(d)(2) and (3) of the CAA, we proposed amendments to 40 CFR part 63, subpart HH by adding requirements for previously unregulated units; specifically, we proposed standards for small glycol dehydration units and storage vessels without the PFE.

In the final amendments for 40 CFR part 63, subpart HH, we have revised the proposed MACT standards for small glycol dehydration units in response to comments that we did not take into account variability in the development of the MACT floor. In our proposal, the MACT standards for existing affected sources was a unit-specific BTEX limit of 1.10×10^{-4} g BTEX/scm-ppmv and for new affected sources was a BTEX limit of 4.66×10^{-6} g BTEX/scm-ppmv. In this final rule, we accounted for variability by using an upper prediction limit to develop a revised BTEX emission limit for existing small glycol dehydration units of 3.28×10^{-4} grams BTEX/standard cubic meters (scm)-parts per million by volume (ppmv) and for new small glycol dehydration units the revised BTEX limit is 4.66×10^{-6} grams BTEX/scm-ppmv. The process for developing these emissions limitations is documented in the Response to Comments document and a technical memorandum, both of which are in the docket.

Finally, as noted above, in response to comments, we are not finalizing MACT standards for storage vessels without the PFE in this rule. We received numerous comments expressing concerns with how we established the proposed standards for this subcategory. In response to such comments, we have re-evaluated the proposed MACT standards and concluded that we need (and intend to gather) additional data on these sources in order to analyze and establish MACT emission standards for this subcategory of storage vessels under section 112(d)(2) and (3) of the CAA. See the Response to Comments document for additional discussion.

2. Changes Made to Amendments Proposed Under the Authority of CAA Section 112(f)(2)

We proposed to eliminate the 0.9 Mg/yr benzene compliance option for large glycol dehydration units because, in the proposed rule, we estimated that the emissions allowed as the result of this compliance option resulted in estimated cancer risks up to 400-in-1-million. We received multiple comments concerning our proposed risk estimate. After reviewing these comments, we discovered that we had significantly overestimated the allowable emissions associated with this compliance option. First, for several sources, including the source that we predicted had the 400-in-1 million MIR, we used an incorrect factor (or multiplier) to scale up actual emissions associated with sources that could utilize the compliance option level of 0.9 Mg/yr to allowables. We used an incorrect factor due to an inadvertent transcription error in our calculations. Second, we learned that the risk assessment supporting the proposed rule erroneously included several area sources, which are not subject to 40 CFR part 63, subpart HH and thus should not have been included in the CAA section 112(f) risk assessment. After revising the risk assessment to remove area sources, and considering the MACT standard promulgated today for small glycol dehydrators pursuant to CAA sections 112(d)(2) and (3), the MIR for the Oil and Natural Gas Production source category based on actual and allowable emissions is 10-in-1 million, compared to the 400-in-1 million[3] based on

[3] At proposal, we used an incorrect factor (or multiplier) in calculating allowable emissions for

Continued

allowable emissions and 40-in-1 million based on actual emissions that were estimated in the proposed rule.

As the result of our revised risk analysis, we have determined that approximately 120,000 people are estimated to have cancer risks at or above 1-in-1 million, compared to 160,000 people estimated in the proposed rule. Total estimated cancer incidence from the source category is 0.02 excess cancer cases per year, or one case in every 50 years. This estimate is unchanged from the proposed rule because the incidence from a small number of sources typically does not affect total incidence reported to one significant figure. The estimate from the proposed rule of maximum chronic non-cancer TOSHI value (0.1) is unchanged, driven by naphthalene emissions from fugitive sources. The maximum acute non-cancer hazard quotient value (9, based on the California EPA reference exposure level (REL) for benzene) is also unchanged from the proposed rule. Although driven by the same pollutant that drives the MIR, benzene, the maximum acute hazard quotient value did not change from the proposed rule because the source driving the acute value was not identified as an area source and, thus, remained in the revised analysis. It is common for the maximum acute hazard quotient and cancer MIR not to coincide because the acute value is strongly dependent on short-term meteorology and the distance to the facility property boundary, whereas the MIR is dependent on long-term meteorology and the distance to census block receptors. There are 13 cases in the source category (out of approximately 1,000 facilities) where the REL is exceeded by more than a factor of 2.

Based on the conservative nature of the acute exposure scenario used in the screening assessment for this source category, the EPA has judged that, considering all associated uncertainties, the potential for effects from acute exposures is low. Screening estimates of acute exposures were evaluated for each HAP at the point of highest off-site exposure for each facility (*i.e.,* not just the census block centroids) assuming that a person is present at this location at a time when both the peak emission rate and worst-case dispersion conditions occur. Although the REL (which indicates the level below which adverse effects are not anticipated) is exceeded in this case, we believe the potential for acute effects is low for several reasons. The acute modeling scenario is worst-case because of the confluence of peak emission rates and worst-case dispersion conditions. Also, the generally sparse populations near the facilities with the highest estimated 1-hour exposures make it less likely that a person would be near the plant to be exposed.

We also conducted a facility-wide risk assessment. The maximum facility-wide risk estimate of 100-in-1 million is unchanged from the proposed rule. Also unchanged from proposal is the fact that the facility-wide risk is driven by emissions from reciprocating internal combustion engines (RICE) and these engines are not part of the Oil and Natural Gas Production source category. In fact, oil and natural gas production operations contribute only about one percent or less to the total facility-wide risks. In the last few years, the Agency has revised the MACT standards for certain RICE. See 75 FR 9648 and 51570. Although it is difficult to discern from the available data which types of RICE are driving the facility-wide risk, it is important to note that the 2005 National Emissions Inventory (NEI) data on which we modeled risk did not take into account the recent MACT revisions to the RICE rule. Finally, our assessment that the potential for significant human health risks due to multipathway exposures or adverse environmental effects is low has not changed since proposal (see 76 FR 52774).

Consistent with the approach established in the Benzene NESHAP, the EPA weighed all health risk measures and information, including the maximum individual cancer risk, the cancer incidence, the number of people exposed to a risk greater than 1-in-1-million, the distribution of risks in the exposed population, and the uncertainty of our risk calculations in determining whether the risk posed by emissions from Oil and Natural Gas Production is acceptable. In this case, because the MIR is well below 100-in-1-million, and because a number of other factors indicate relatively low risk concern, including low cancer incidence, low potential for adverse environmental effects or human health multi-pathway, and unlikely chronic and acute noncancer health impacts, we conclude that the level of risk associated with the Oil and Natural Gas Production source category MACT standards (including the small glycol dehydrator MACT standard issued here) is acceptable.[4]

In making our proposed ample margin of safety determination under CAA section 112(f)(2), we subsequently evaluated the risk reductions and costs associated with various emissions control options to determine whether we should impose additional standards to reduce risks further. As stated above, we made certain revisions to the risk assessment in response to comments and the resulting MIR for 40 CFR part 63, subpart HH is 10-in-1 million. We have not identified any emission control options that would reduce emissions and risk associated with subpart HH sources for glycol dehydration units and storage vessels. Our proposed amendment to remove the 0.9 Mg/yr compliance option does not affect the risk driver, which is fugitive emissions. As a result, we are retaining the 0.9 Mg/yr compliance option in the final rule. We have determined that the risks associated with the level of emissions allowed by the MACT standards are driven by fugitive emissions (*i.e.,* leaks).

Since a LDAR program is the typical method for reducing emissions from fugitive sources, we considered requiring a LDAR program to reduce risk for this source category. The NEI dataset for this source category contains approximately 2,500 emission points that we characterized as fugitive. These emission points are located at 639 facilities. The fugitive emissions associated with those 639 facilities are 747 tons of HAP.

In evaluating the effectiveness of a LDAR program at these facilities we looked at two different LDAR programs—one is a program equivalent to 40 CFR part 60, subpart VV, and the second is a more stringent program equivalent to 40 CFR part 60, subpart VVa.[5] A LDAR program equivalent to subpart VV can achieve emission reductions of approximately 39 percent with capital and annual costs of

the source that, at proposal, had an estimated MIR of 400-in-1 million. Since proposal, we have learned that this source is an area source and thus is not subject to the Subpart HH MACT standards. As such, we removed this source from our section 112(f) risk analysis. In any event, we have determined that even if this area source were to have actual emissions at the 0.9 Mg/yr level, its risk would be 3-in-1 million.

[4] We reach the same conclusion even if we do not consider the new MACT for small glycol dehydrators in our acceptability determination. Indeed, focusing solely on the standards in the existing MACT, the level of risk associated with such standards would remain 10-in-1 million, and thus our acceptability determination does not change. There is one facility that is a small glycol dehydrator that has an MIR of 10-in-1 million. After imposition of the MACT for small glycol dehydrators, however, this unit would have an MIR of 7-in-1 million. Also, see memorandum titled *Supplemental Facility Information Obtained from Various State/Local Agencies and Additional Analysis,* March 20, 2012.

[5] See memorandum titled *Equipment Leak Emission Reduction and Cost Analysis for Well Pads, Gathering and Boosting Stations, and Transmission and Storage Facilities Using Emission and Cost Data from the Uniform Standards,* April 17, 2012.

$237,700 and $79,419 per facility, respectively. Therefore, such a program for the 639 facilities would be expected to reduce emissions by 249 tons of HAP with total capital and annual costs of $152 million and $50.7 million, respectively. The cost effectiveness would be approximately $204,000 per ton of HAP.

A LDAR program equivalent to 40 CFR part 60, subpart VVa can achieve emission reductions of approximately 43 percent overall with capital and annual costs of $241,000 and $82,900 per facility, respectively. Therefore, an LDAR program for the 639 facilities would be expected to reduce emissions by 275 tons of HAP, with total capital and annual costs of $154 million and $53 million, respectively. The cost effectiveness would be approximately $193,000 per ton of HAP reduced. These additional control requirements would reduce the MIR for the source category from 10-in-1 million to approximately 7-in-1 million.

As explained in the proposal, in accordance with the approach established in the Benzene NESHAP, we weigh all health risk measures and information considered in the risk acceptability determination, along with the costs and economic impacts of emissions controls, technological feasibility, uncertainties and other relevant factors, in making our ample margin of safety determination and deciding whether standards are necessary to reduce risks further. Considering all of this information, we conclude that the costs of the options analyzed are not reasonable considering the emissions reductions and risk reductions potentially achievable with the control measures evaluated. Thus, we conclude that the MACT standards in 40 CFR part 63, subpart HH (coupled with the new MACT standard for small glycol dehydrators) provide an ample margin of safety to protect public health and prevent adverse environmental effects. Accordingly, we are re-adopting those standards to satisfy the requirements of CAA section 112(f).

3. Changes Made to Standards Proposed Under the Authority of CAA Section 112(d)(6)

As discussed in detail in the preamble for the proposed rule (76 FR 52784), we conducted a technology review for glycol dehydration units, storage vessels and equipment leaks under the authority of CAA section 112(d)(6). We assessed developments in practices, processes and control technologies sources for those regulated under the initial NESHAP and determined that it was cost-effective to lower the leak definition for valves at natural gas processing plants. We did not identify developments in practices, processes and control technologies for glycol dehydration units and storage vessels. As a result of this assessment, we proposed revisions to the equipment leak requirements in 40 CFR part 63, subpart HH to lower the leak definition for valves to an instrument reading of at least 500 ppm. No significant changes since proposal were made to the equipment leak standards proposed under the authority of section 112(d)(6) of the CAA.[6]

4. Other Changes to the Proposed Rule

We are revising the emission reduction demonstrated using the manufacturers performance test from 98.0 percent to 95.0 percent. Specifically, if an owner or operator chooses to install a combustion control device that is tested under, and passes, the prescribed manufacturers performance test the final rule states that the control device has demonstrated a destruction efficiency of 95.0 percent. This change is a result of comments and data provided on the actual performance of these devices in the field.

In the proposed rule, we proposed that the standards apply at all times and removed provisions that provided an exemption from the emission standards during SSM. In response to comments that the monitoring and reporting provisions related to excursions occurring during SSM events that remain in the subpart suggest exemption and therefore should be removed, we are removing these provisions in the final rule.

Refer to the Reponses to Comments document, available in the docket, for detailed discussion regarding these changes.

B. What are the significant changes since proposal for the Natural Gas Transmission and Storage (subpart HHH) source category?

1. Changes Made to Amendments Proposed Under the Authority of CAA Sections 112(d)(2) and (3)

Under the authority of sections 112(d)(2) and (3) of the CAA, we proposed amendments to 40 CFR part 63, subpart HHH by adding requirements for previously unregulated units; specifically, we proposed standards for small glycol dehydration units.

In the final amendments for 40 CFR part 63, subpart HHH, we have revised the proposed BTEX limits for small glycol dehydration units in response to comments that we did not take into account variability in the development of the MACT floor. We had proposed a unit-specific BTEX emission limit of 6.42×10^{-5} grams BTEX/scm-ppmv for existing sources and a BTEX limit of 1.10×10^{-5} g BTEX/scm-ppmv for new sources. In the final rule, we accounted for variability by using an upper prediction limit to develop a revised emission limit for existing affected sources of 3.10×10^{-4} g BTEX/scm-ppmv and for new affected sources is a BTEX limit of 5.44×10^{-5} grams BTEX/scm-ppmv. The process for developing these emissions limitations is documented in the response to comments document and a technical memorandum both of which can be found in the docket.

2. Changes to Amendments Proposed Under the Authority of CAA Section 112(f)(2)

We proposed to eliminate the 0.9 Mg/yr benzene compliance option for large glycol dehydration unit process vents because, in the proposed rule, we estimated that the emissions allowed as the result of this compliance option resulted in estimated cancer risks up to 90-in-1-million. In response to comments, we learned that the risk assessment supporting the proposed rule erroneously included some sources that have permanently shut down, and several area sources, which are not subject to 40 CFR part 63, subpart HHH and, thus, should not have been included in the CAA section 112(f) risk assessment. After revising the risk assessment to remove these sources and considering the MACT standards promulgated here pursuant to CAA section 112(d)(2) and (3), the MIR for the Natural Gas Transmission and Storage source category based on actual and allowable emissions is 20-in-1 million, compared to the 90-in-1 million based on allowable emissions and 20-in-1 million based on actual emissions estimated in the proposed rule.

As the result of our revised risk analysis, we have determined that approximately 1,100 people are estimated to have cancer risks at or above 1-in-1 million, compared to 2,500 people estimated in the proposed rule. Total estimated cancer incidence from the source category is 0.001 excess cancer cases per year, or one case in every 1,000 years. This estimate is unchanged from the proposed rule

[6] Memorandum from Brown, Heather, EC/R Inc., to Moore, Bruce, U.S. EPA, titled *Technology Review for the Final Amendments to Standards for the Oil and Natural Gas Production and Natural Gas Transmission and Storage Source Categories.*

because the incidence from a small number of sources typically does not affect total incidence reported to one significant figure. The estimate from the proposed rule of maximum chronic non-cancer TOSHI value (0.2) is unchanged, driven by benzene emissions from fugitive sources. The maximum acute non-cancer hazard quotient value (4, based on the benzene REL) changed from the proposed rule; the value in the proposed rule was 5, but was associated with an area source that was removed from the risk assessment. There are two cases in the source category (out of approximately 300 facilities) where the REL is exceeded by more than a factor of 2.

Based on the conservative nature of the acute exposure scenario used in the screening assessment for this source category, the EPA has judged that, considering all associated uncertainties, the potential for effects from acute exposures is low. Screening estimates of acute exposures were evaluated for each HAP at the point of highest off-site exposure for each facility (*i.e.,* not just the census block centroids) assuming that a person is present at this location at a time when both the peak emission rate and worst-case dispersion conditions occur. Although the REL (which indicates the level below which adverse effects are not anticipated) is exceeded in this case, we believe the potential for acute effects is low for several reasons. The acute modeling scenario is worst-case because of the confluence of peak emission rates and worst-case dispersion conditions. Also, the generally sparse populations near the facilities with the highest estimated 1-hour exposures make it less likely that a person would be near the plant to be exposed.

We also conducted a facility-wide risk assessment. The maximum facility-wide risk estimate of 200-in-1 million is unchanged from the proposed rule. Also unchanged from proposal is the fact that the facility-wide risk is driven by emissions from reciprocating internal combustion engines (RICE) and these engines are not part of the Natural Gas Transmission and Storage source category. In fact, natural gas transmission and storage operations contribute only about one percent or less to the total facility-wide risks. In the last few years, the Agency has revised the MACT standards for certain RICE. See 75 FR 9648 and 51570. Although it is difficult to discern from the available data which types of RICE are driving the facility-wide risk, it is important to note that the 2005 NEI data on which we modeled risk did not take into account the recent MACT revisions to the RICE rule. Finally, our assessment that the potential for significant human health risks due to multipathway exposures or adverse environmental effects is low has not changed since proposal (see 76 FR 52774).

Consistent with the approach established in the Benzene NESHAP, the EPA weighed all health risk measures and information, including the maximum individual cancer risk, the cancer incidence, the number of people exposed to a risk greater than 1-in-1-million, the distribution of risks in the exposed population and the uncertainty of our risk calculations in determining whether the risk posed by emissions from natural gas transmission and storage is acceptable. In this case, because the MIR is well below 100-in-1-million, and because a number of other factors indicate relatively low risk concern, including low cancer incidence, low potential for adverse environmental effects or human health multi-pathway effects, and unlikely chronic and acute noncancer health impacts, we conclude that the level of risk associated with the Natural Gas Transmission and Storage source category MACT standards (including those MACT standards issued here) is acceptable.[7]

In making our proposed ample margin of safety determination under CAA section 112(f)(2), we subsequently evaluated the risk reductions and costs associated with various emissions control options to determine whether we should impose additional standards to reduce risks further. As stated above, we made certain revisions to the risk assessment in response to comments and the resulting MIR for 40 CFR part 63, subpart HHH is 20-in-1 million. We have not identified any emission control options that would reduce emissions and risk associated with subpart HHH sources for glycol dehydration units. Our proposed amendment to remove the 0.9 Mg/yr compliance option does not affect the risk driver, which is fugitive emissions. As a result, we are retaining the 0.9 Mg/yr compliance option in the final rule.

We have determined that the risks associated with the level of emissions allowed by the MACT standards are driven by fugitive emissions (*i.e.,* leaks). Since a LDAR program is the typical method for reducing emissions from fugitive sources, we evaluated the costs and emissions reductions associated with requiring such a program to reduce risk for this source category. The NEI dataset for the natural gas transmission and storage source category contains approximately 314 emission points that we characterized as being fugitive in nature. These emission points are located at 212 facilities. The fugitive emissions associated with those 212 facilities are 187 tons of HAP.

In evaluating the effectiveness of a LDAR program at these facilities we looked at two different LDAR programs—one is a program equivalent to 40 CFR part 60, subpart VV, and the second is a more stringent program equivalent to 40 CFR part 60, subpart VVa.[8] A LDAR program equivalent to subpart VV can achieve emission reductions of approximately 51 percent with capital and annual costs of $361,800 and $142,600 per facility, respectively. Therefore, such a program for 212 facilities would be expected to reduce emissions by 95.4 tons of HAP and have total capital and annual costs of $76.7 million and $30.2 million, respectively. The cost effectiveness would be approximately $317,000 per ton of HAP.

A LDAR program equivalent to 40 CFR part 60, subpart VVa can achieve emission reductions of approximately 78 percent overall with capital and annual costs of $369,500 and $154,300 per facility, respectively. Therefore, a LDAR program for 212 facilities would be expected to reduce emissions by 146 tons of HAP with total capital and annual costs of $78.3 million and $32.7 million, respectively. The cost effectiveness would be approximately $224,000 per ton of HAP. These additional control requirements would reduce the MIR from the source category to approximately 3-in-1 million for the subpart VVa level of control and 7-in-1-million for the 40 CFR part 60, subpart VV level of control.

As explained in the proposal, in accordance with the approach established in the Benzene NESHAP, we weigh all health risk measures and information considered in the risk acceptability determination, along with the costs and economic impacts of emissions controls, technological feasibility, uncertainties and other relevant factors, in making our ample margin of safety determination and

[7] We reach the same conclusion even if we do not consider the new MACT for small glycol dehydrators in our acceptability determination. Indeed, focusing solely on the standards in the existing MACT, the level of risk associated with such standards would remain 20-in-1 million, and thus our acceptability determination would not change. The glycol dehydrators analyzed all had risks well below 20-in-1 million.

[8] See memorandum titled *Equipment Leak Emission Reduction and Cost Analysis for Well Pads, Gathering and Boosting Stations, and Transmission and Storage Facilities Using Emission and Cost Data from the Uniform Standards,* dated April 17, 2012.

deciding whether standards are necessary to reduce risks further. Considering all of this information, we conclude that the costs of the options analyzed are not reasonable considering the emissions reductions and risk reductions potentially achievable with the control measures. Thus, we conclude that the MACT standards in 40 CFR part 63, subpart HHH (coupled with the new MACT standard for small glycol dehydrators) provide an ample margin of safety to protect public health and prevent adverse environmental effects. Accordingly, we are re-adopting those standards to satisfy the requirements of CAA section 112(f)(2).

3. Changes Made to Amendments Proposed Under the Authority of CAA Section 112(d)(6)

As discussed in detail in the preamble for the proposed rule (76 FR 52784), we conducted a technology review for glycol dehydration units under the authority of CAA section 112(d)(6). We did not identify developments in practices, processes and control technologies for large glycol dehydration units. As a result of this assessment, we did not propose amendments to 40 CFR part 63, subpart HHH. We have not made any changes since proposal under the authority of CAA section 112(d)(6).[9] Further discussion on our technology review analysis can be found in section X.C of this preamble, and in the Response to Comments document.

4. Other Changes to the Proposed Rule

We are revising the emission reduction efficiency demonstration using the manufacturer's performance test from 98.0 percent to 95.0 percent. Specifically, if an owner or operator chooses to install a combustion control device that is tested under, and passes, the prescribed manufacturer's performance test, the final rule states that the control device has demonstrated a reduction efficiency of 95.0 percent. This change is a result of comments and data provided on the actual performance of these devices in the field.

In the proposed rule, we proposed that the standards apply at all times and removed provisions that provided an exemption from the emission standards during SSM. In response to comments that the monitoring and reporting provisions related to excursions occurring during SSM events that remain in the subpart suggest exemption and therefore should be removed, we are removing these provisions in the final rule.

VIII. Compliance Related Issues Common to the NSPS and NESHAP

A. How do the rules address startup, shutdown and malfunction?

The United States Court of Appeals for the District of Columbia Circuit vacated portions of two provisions in the EPA's CAA section 112 regulations governing the emissions of HAP during periods of SSM. *Sierra Club* v. *EPA,* 551 F.3d 1019 (D.C. Cir. 2008), cert. denied, 130 S. Ct. 1735 (U.S. 2010). Specifically, the Court vacated the SSM exemption contained in 40 CFR 63.6(f)(1) and 40 CFR 63.6(h)(1), that are part of a regulation, commonly referred to as the "General Provisions Rule," that the EPA promulgated under section 112 of the CAA. When incorporated into CAA section 112(d) regulations for specific source categories, these two provisions exempt sources from the requirement to comply with the otherwise applicable CAA section 112(d) emission standard during periods of SSM.

As proposed in the NESHAP, we have eliminated the SSM exemption in this rule. Consistent with *Sierra Club* v. *EPA,* the EPA has established standards in both rules that apply at all times. We have also revised Table 3 (the NESHAP General Provisions table) in several respects. For example, we have eliminated the incorporation of the NESHAP General Provisions' requirement that the source develop an SSM plan. We have also eliminated or revised certain NESHAP recordkeeping and reporting that related to the SSM exemption. The EPA has attempted to ensure that we have not included in the regulatory language, for the NSPS and NESHAP, any provisions that are inappropriate, unnecessary or redundant in the absence of the SSM exemption.

In establishing the standards in both rules, the EPA has taken into account startup and shutdown periods and, for the reasons explained in section IX of this preamble for the NSPS and in section X of this preamble for the NESHAP, did not establish different standards for those periods. Based on the information available in the record about actual operations during startups and shutdowns, we believe that operations and emissions do not differ from normal operations during these periods such that it warrants a separate standard. Therefore, we have not proposed different standards for these periods.

Periods of startup, normal operations and shutdown are all predictable and routine aspects of a source's operations. However, by contrast, malfunction is defined as a "sudden, infrequent, and not reasonably preventable failure of air pollution control and monitoring equipment, process equipment, or a process to operate in a normal or usual manner * * *" (40 CFR 63.2) and as "any sudden, infrequent, and not reasonably preventable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner * * *" (40 CFR 60.2). The EPA has determined that CAA sections 111 and 112 do not require that emissions that occur during periods of malfunction be factored into development of CAA section 111 or 112 standards.

CAA section 111 standards—See section III of this preamble for a detailed discussion on how the EPA sets or revises CAA section 111 NSPS to reflect the degree of emission limitation achievable through the application of the BSER.

CAA section 112 standards—Under CAA section 112, emissions standards for new sources must be no less stringent than the level "achieved" by the best controlled similar source and for existing sources, generally must be no less stringent than the average emission limitation "achieved" by the best performing 12 percent of sources in the category. Nothing in CAA section 112 directs the agency to consider malfunctions in determining the level "achieved" by the best performing or best controlled sources when setting emission standards. Moreover, while the EPA accounts for variability in setting emissions standards consistent with the CAA section 112 case law, nothing in that case law requires the agency to consider malfunctions as part of that analysis. CAA section 112 uses the concept of "best controlled" and "best performing" unit in defining the level of stringency that CAA section 112 performance standards must meet. Applying the concept of "best controlled" or "best performing" to a unit that is malfunctioning presents significant difficulties, as malfunctions are sudden and unexpected events.

Further, accounting for malfunctions in setting NESHAP or NSPS standards would be difficult, if not impossible, given the myriad different types of malfunctions that can occur across all sources in the category and given the difficulties associated with predicting or accounting for the frequency, degree and duration of various malfunctions that might occur. As such, the performance of units that are malfunctioning is not "reasonably" foreseeable. See, *e.g., Sierra Club* v.

[9] See footnote 6.

EPA, 167 F.3d 658, 662 (D.C. Cir. 1999) (''[T]he EPA typically has wide latitude in determining the extent of data-gathering necessary to solve a problem. We generally defer to an agency's decision to proceed on the basis of imperfect scientific information, rather than to 'invest the resources to conduct the perfect study.' ''); see, also, *Weyerhaeuser Co.* v. *Costle,* 590 F.2d 1011, 1058 (D.C. Cir. 1978) (''In the nature of things, no general limit, individual permit, or even any upset provision can anticipate all upset situations. After a certain point, the transgression of regulatory limits caused by 'uncontrollable acts of third parties,' such as strikes, sabotage, operator intoxication or insanity, and a variety of other eventualities, must be a matter for the administrative exercise of case-by-case enforcement discretion, not for specification in advance by regulation.''). In addition, in the NESAHP context, the goal of a best controlled or best performing source is to operate in such a way as to avoid malfunctions of the source and accounting for malfunctions could lead to standards that are significantly less stringent than levels that are achieved by a well-performing non-malfunctioning source. Similarly, in the NSPS context, accounting for malfunctions when setting standards of performance under CAA section 111, which reflect the degree of emission limitation achievable through ''the application of the best system of emission reduction'' that the EPA determines is adequately demonstrated could lead to standards that are significantly less stringent than levels that are achieved by a well-performing non-malfunctioning source. The EPA's approach to malfunctions is consistent with CAA section 112 and CAA section 111 and is a reasonable interpretation of the statute.

Finally, the EPA recognizes that even equipment that is properly designed and maintained can sometimes fail and that such failure can sometimes cause a violation of the relevant emission standard. See, *e.g., State Implementation Plans: Policy Regarding Excessive Emissions During Malfunctions, Startup, and Shutdown* (September 20, 1999); *Policy on Excess Emissions During Startup, Shutdown, Maintenance, and Malfunctions* (February 15, 1983). The EPA is, therefore, adding to the final NSPS and NESHAP an affirmative defense to civil penalties for violations of emission standards that are caused by malfunctions. See 40 CFR 63.761 for sources subject to the Oil and Natural Gas Production MACT standards; 40 CFR 63.1271 for sources subject to the Natural Gas Transmission and Storage MACT standards (defining ''affirmative defense'' to mean, in the context of an enforcement proceeding, a response or defense put forward by a defendant, regarding which the defendant has the burden of proof, and the merits of which are independently and objectively evaluated in a judicial or administrative proceeding). We also have added other regulatory provisions to specify the elements that are necessary to establish this affirmative defense; a source subject to the Oil and Natural Gas Production or Natural Gas Transmission and Storage MACT standards must prove by a preponderance of the evidence that it has met all of the elements set forth in 40 CFR 63.762 and a source subject to the Natural Gas Transmission and Storage NSPS must prove by a preponderance of the evidence that it has met all of the elements set forth in 40 CFR 60.41Da (NSPS). See 40 CFR 22.24. The criteria ensure that the affirmative defense is available only where the event that causes a violation of the emission standard meets the narrow definition of malfunction in 40 CFR 60.2 (NSPS) and 40 CFR 63.2 (NESHAP), respectively, (sudden, infrequent, not reasonably preventable and not caused by poor maintenance and/or careless operation). For example, the final NSPS and NESHAP provide that to successfully assert the affirmative defense, the source must prove by a preponderance of the evidence that the violation ''[w]as caused by a sudden, infrequent, and unavoidable failure of air pollution control and process equipment, or a process to operate in a normal or usual manner. * * *'' The criteria also are designed to ensure that steps are taken to correct the malfunction, to minimize emissions in accordance with 40 CFR 63.762 for sources subject to the Oil and Natural Gas Production MACT standards, 40 CFR 63.1272 for sources subject to the Natural Gas Transmission and Storage MACT standards, and 40 CFR 60.5415(h) for the Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution, and to prevent future malfunctions. For example, the final NSPS and NESHAP provide that the source must prove by a preponderance of the evidence that ''[r]epairs were made as expeditiously as possible when a violation occurred * * *'' and that ''[a]ll possible steps were taken to minimize the impact of the violation on ambient air quality, the environment and human health. * * *'' In any judicial or administrative proceeding, the Administrator may challenge the assertion of the affirmative defense and, if the respondent has not met its burden of proving all of the requirements in the affirmative defense, appropriate penalties may be assessed in accordance with section 113 of the CAA (see also 40 CFR part 22.27).

The EPA proposed and is now finalizing an affirmative defense in the final NSPS and NESHAP in an attempt to balance a tension, inherent in many types of air regulations, to ensure adequate compliance, while simultaneously recognizing that, despite the most diligent of efforts, emission standards may be violated under circumstances beyond the control of the source. The EPA must establish emission standards that ''limit the quantity, rate, or concentration of emissions of air pollutants on a continuous basis.'' 42 U.S.C. 7602(k) (defining ''emission limitation and emission standard''). See, generally, *Sierra Club* v. *EPA,* 551 F.3d 1019, 1021 (D.C. Cir. 2008). Thus, the EPA is required to ensure that CAA section 112 emissions standards are continuous. The affirmative defense for malfunction events meets this requirement by ensuring that, even where there is a malfunction, the emission standard is still enforceable through injunctive relief. While ''continuous'' standards, on the one hand, are required, there is also case law indicating that, in many situations, it is appropriate for the EPA to account for the practical realities of technology. For example, in *Essex Chemical* v. *Ruckelshaus,* 486 F.2d 427, 433 (D.C. Cir. 1973), the District of Columbia Circuit acknowledged that, in setting standards under CAA section 111, ''variant provisions'' such as provisions allowing for upsets during startup, shutdown and equipment malfunction ''appear necessary to preserve the reasonableness of the standards as a whole and that the record does not support the 'never to be exceeded' standard currently in force.'' See, also, *Portland Cement Ass'n* v. *Ruckelshaus,* 486 F.2d 375 (D.C. Cir. 1973). Though intervening case law such as *Sierra Club* v. *EPA* and the CAA 1977 amendments call into question the relevance of these cases today, they support the EPA's view that a system that incorporates some level of flexibility is reasonable. The affirmative defense simply provides for a defense to civil penalties for violations that are proven to be beyond the control of the source. By incorporating an affirmative defense, the EPA has formalized its approach to upset events. In a Clean

Water Act setting, the Ninth Circuit required this type of formalized approach when regulating ''upsets beyond the control of the permit holder.'' *Marathon Oil Co.* v. *EPA,* 564 F.2d 1253, 1272–73 (9th Cir. 1977); see, also, *Mont. Sulphur & Chem. Co.* v. *EPA,* 2012 U.S. App. LEXIS 1056 (Jan 19, 2012) (rejecting industry argument that reliance on the affirmative defense was not adequate). *But see Weyerhaeuser Co.* v. *Costle,* 590 F.2d at 1057–58 (holding that an informal approach is adequate). The affirmative defense provisions give the EPA the flexibility to both ensure that its emission standards are ''continuous,'' as required by 42 U.S.C. 7602(k), and account for unplanned upsets and, thus, support the reasonableness of the standard as a whole.

Refer to preamble section IX for the NSPS, preamble section X for the NESHAP and the Response to Comments document for both the NSPS and the NESHAP, available in the docket, for detailed discussions regarding these changes.

B. How do the NSPS and NESHAP provide for compliance assurance?

The final rule includes various notification, recordkeeping and reporting requirements that we believe provide a robust compliance assurance program, while reducing burden and streamlining requirements. The EPA also considered a variety of innovative compliance approaches that could maximize compliance and transparency, while minimizing burden on the regulated community and regulators. More detailed information on public comments received and the EPA's responses are included in sections IX and X of the preamble or in the response to comments document.

1. Notification, Recordkeeping and Reporting Requirements

For well completions, owners or operators are required to submit an email notification no later than 2 days prior to each anticipated well completion. The notification must identify the owner or operator and provide the American Petroleum Institute (API) well number, geographical coordinates of the affected wells and the estimated date of commencement of the flowback period immediately following hydrofracturing. The owner or operator must keep records identifying each well completion operation and documenting the portions of the flowback period when the gas was recovered, combusted or vented.

Annually, owners or operators of all affected facilities under the NSPS, including gas wells, compressors, pneumatic controllers, storage vessels and gas processing plants, must report any deviation from the NSPS requirements during the reporting period. Each annual report must include a signed certification by a senior company official that attests to the truth, accuracy and completeness of the report. For affected gas wells, the report must also identify each well completion conducted during the reporting period and submit detailed completion records for each well as part of the annual report.

In the final rule, the recordkeeping and reporting requirements for well completions also provide a streamlining option that owners and operators may choose in lieu of the standard annual reporting requirements. The alternative, streamlined annual report for gas well affected facilities requires submission of a list, with identifying information of all affected gas wells completed, electronic or hard copy photographs documenting REC in progress for each well for which REC was required and the self-certification required in the standard annual report. The operator retains a digital image of each REC in progress. The image must include a digital date stamp and geographic coordinates stamp to help link the photograph with the specific well completion operation. The owner or operator is not required to submit detailed completion records as part of the annual report.

For centrifugal compressors with wet seal systems, the annual report must include identification of each affected facility constructed, modified or reconstructed during the reporting period. The annual report for reciprocating compressors must identify each reciprocating compressor constructed, modified or reconstructed during the reporting period. The report also must include, for each affected compressor, the elapsed time of operation since the most recent rod packing change as of the end of the reporting period. For affected pneumatic controllers and storage vessels, the annual report must identify each affected facility constructed, modified or reconstructed during the reporting period.

Owners or operators who conduct certain performance tests on control devices must report results of those tests using the Electronic Reporting Tool (ERT). Further discussion of reporting of emissions tests is presented in section VIII.D of this preamble.

NESHAP

The final amendments to 40 CFR part 63, subparts HH and 40 CFR part 63, subpart HHH revise certain recordkeeping requirements. Specifically, facilities using carbon adsorbers as a control device are now required to keep records of their carbon replacement schedule and records of each carbon replacement. We are requiring that owners and operators that use a manufacturer's tested control device keep records of visible emissions readings and flowrate calculations and records of periods when the pilot flame is absent. The final amendments require records of the date of each semi-annual maintenance inspection be maintained. Finally, owners and operators are required to keep records of the occurrence and duration of each malfunction or operation of the air pollution control equipment and monitoring equipment.

In conjunction with the final MACT standards for small glycol dehydration units, owners and operators of such units are required to submit an initial notification within 1 year after becoming subject to 40 CFR part 63, subpart HH or by October 15, 2013, whichever is later.

Similarly, in conjunction with the final MACT standards for small glycol dehydration units in the final 40 CFR part 63, subpart HHH amendments, owners and operators of small glycol dehydration units are required to submit an initial notification within 1 year after becoming subject to subpart HHH or by October 15, 2013, whichever is later.

The final amendments to 40 CFR part 63, subpart HH and 40 CFR part 63, subpart HHH include new requirements for the contents of Notification of Compliance Status Reports. The owners and operators are required to include an electronic copy of the performance test results for the manufacturer's tested control device, if applicable; the predetermined carbon replacement schedule for carbon adsorbers, if applicable; and data related to the manufacturer's performance tests conducted for certain models of control devices, if compliance is being achieved using the manufacturer's performance tests.

The final amendments to the NESHAP also include additional requirements for the contents of periodic reports. Each semiannual report must include a signed certification by a senior company official that attests to the truth, accuracy and completeness of the report. For both 40 CFR part 63, subpart HH and 40 CFR part 63, subpart HHH, in the final amendments, periodic reports are

required to include periodic test results and information regarding any carbon replacement events that occurred during the reporting period. Owners and operators are also required to include in the periodic reports information regarding any excursions that occur when the inlet gas flow rate deviates from that identified in the manufacturer's performance test, and any excursions caused when visible emissions exceed the maximum allowable duration.

Owners or operators who conduct certain performance tests on control devices must report results of those tests using the ERT. Further discussion of reporting of emissions tests is presented in section VIII.C below.

2. Innovative Compliance Approaches

At proposal, given the number and diversity of sources potentially affected by the NSPS and/or the NESHAP, we solicited comments on optional compliance tools that could reduce compliance burden and enhance transparency. Specifically, we asked for suggestions on: (1) Registration of wells and advance notification of planned completions; (2) use of third party verification; and (3) electronic reporting using existing mechanisms. We received comments on each of the topics above and have presented summaries of those comments and the EPA's responses in the Response to Comments document. The commenters were generally opposed to third party verification. However, one suggestion was a voluntary random verification program, similar to one used in the past for gasoline marketing, where operators who participated in this program potentially could receive lower priority for enforcement inspections by regulators. Other suggested innovative approaches include use of social media, including Facebook and Twitter, plus new technologies such as quick response codes, to provide timely public notification and access to compliance records for individual wells and other affected facilities. Other suggestions included use of a centralized database for industry and public access to compliance information. Further discussion of these approaches is provided in the response to comments. While we considered these suggestions, we did not adopt them in the final rule, for reasons explained further in the Responses to Comments document.

C. What are the requirements for submission of performance test data to the EPA?

The EPA must have performance test data to conduct effective reviews of CAA sections 111, 112 and 129 standards, as well as for many other purposes, including compliance determinations, emission factor development and annual emission rate determinations.

As stated in the proposal preamble, the EPA is taking a step to increase the ease and efficiency of data submittal and data accessibility. Specifically, the EPA is requiring owners and operators of oil and natural gas sector facilities to submit electronic copies of required performance test reports.

As mentioned in the proposal preamble, data entry will be conducted through an electronic emissions test report structure called the ERT. The ERT will generate an electronic report which will be submitted to the EPA's Central Data Exchange (CDX) through the Compliance and Emissions Data Reporting Interface (CEDRI). A description of the ERT can be found at *http://www.epa.gov/ttn/chief/ert/index.html* and CEDRI can be accessed through the CDX Web site (*www.epa.gov/cdx*).

The requirement to submit performance test data electronically to the EPA does not create any additional performance testing and would apply only to those performance tests conducted using test methods that are supported by the ERT. A list of the pollutants and test methods supported by the ERT is available at *http://www.epa.gov/ttn/chief/ert/index.html*.

The major advantages of electronic reporting are more fully explained in the proposal preamble.

An important benefit of using the ERT is that the performance test data will become available to the public through WebFIRE. Having such data publicly available enhances transparency and accountability.

In summary, in addition to supporting regulation development, control strategy development and other air pollution control activities, having an electronic database populated with performance test data will save industry; state, local and tribal agencies; and the EPA significant time, money and effort while improving the quality of emission inventories and, as a result, air quality regulations.

IX. Summary of Significant NSPS Comments and Responses

For purposes of this document, the text within the comment summaries was provided by the commenter(s) and represents their opinion(s), regardless of whether the summary specifically indicates that the statement is from a commenter(s) (*e.g.,* ''The commenter states'' or ''The commenters assert''). The comment summaries do not represent the EPA's opinion unless the response to the comment specifically agrees with all or a portion of the comment.

A. Major Comments Concerning Applicability

1. Activities That Constitute a Modification

Comment: Referring to the definition of ''modification'' in section 111(a)(4) of the CAA, one commenter asserts that a modification occurs only if two things happen: (1) There must be a ''physical change or change in the method of operation,'' and (2) the change must result in an emissions increase.

The commenter states that, in the context of the New Source Review program, the District of Columbia Circuit Court has opined that ''Congress's use of the word 'any' in defining a 'modification' means that all types of 'physical changes' are covered'' (*New York* v. *EPA,* 443 F.3d 880, 890 (D.C. Cir. 2006)) and that the District of Columbia Circuit Court has determined that ''the plain language of the CAA indicates that Congress intended to apply NSR to changes that increase actual emissions instead of potential or allowable emissions.'' *New York* v. *EPA,* 413 F.3d 3, 40 (DC Cir. 2005).

However, according to the commenter, the Supreme Court has concluded that the CAA section 111 definition of modification does not have to have the same meaning under the NSPS and New Source Review (NSR) programs (*Environmental Defense* v. *Duke Energy Corp.,* 127 S. Ct. 1423, 1434 (2007)), and, thus, the EPA has latitude within the context of CAA section 111 to implement different rules regarding modifications.

The commenter believes, in particular, that the EPA's regulatory definition of ''modification'' under the NSPS program provides several categories of activities that alone, are not to be considered modifications, including ''maintenance, repair, and replacement which the Administrator determines to be routine for a source category,'' and ''an increase in production rate that can be accomplished without a capital expenditure.'' 40 CFR 60.14(e). The commenter believes these provisions reflect the fact that Congress established the NSPS program for ''new'' sources. According to the commenter, without these exclusions, even the most minor activities would convert an existing source into a ''new source.'' The commenter states that the premise behind characterizing these activities as

not being ''changes'' is that they all contemplate that the plant will continue to be operated in a manner consistent with its original design and, thus, is not a ''new'' facility.

We also received a number of comments objecting to consideration of recompletion activities [10] as modifications, claiming that it is a significant departure from the definition of ''modification'' under the General Provision at 40 CFR 60.14. Some commenters argue that well completion expenditures do not meet the regulatory definition of ''capital expenditure'' while others argue that they are maintenance activities excluded in 40 CFR 60.14 others note that we have not traditionally regulated temporary ''construction'' activities.[11]

Response: In this final rule, the EPA addresses modifications in the context of well completions and has deleted the proposed definition of ''modification,'' though the underlying rationale presented in the proposal remains, and we are providing alternative regulatory text. Pursuant to this final rule and as discussed below, well completions conducted on gas wells that are refractured on or after the effective date of this rule are considered modifications and subject to the NSPS, with the exception of such well completions that, immediately upon flowback, use emission control techniques otherwise required for new wells and satisfy other requirements for gas well facilities, including notification, recordkeeping and reporting requirements.

As discussed in the proposal, the EPA has chosen to depart from the definition of modification in 40 CFR 60.14 with respect to regulation of wells that primarily produce natural gas. As explained in the proposal and elsewhere in the preamble for this rule, the VOC emissions from the flowback following refracturing of gas wells are significant, the EPA has identified cost-effective controls to reduce VOC emissions during this operating phase, and these controls are required for only a relatively short time during the well's operating life. The EPA therefore concludes that it is appropriate for treatment of these activities to depart from the definition of modification in 40 CFR 60.14 to ensure that emissions from these activities are controlled.

We do not in this package question the broad appropriateness of the NSPS General Provisions at 40 CFR 60.14. However, as the General Provisions on modification in 40 CFR 60.14 themselves recognize, they may not be appropriate in all cases. Given the significant, although short-term, increase in emissions from flowback caused by refracturing activities when such activities are not controlled, and the cost-effective nature of the control on such emissions, we have concluded that covering these refracturing activities is appropriate even if it requires departing from the General Provisions' definition of modification.

Specifically, we are providing in the final rule at 40 CFR 60.5365:

(h) The following provisions apply to gas well facilities that are hydraulically refractured.

(1) A gas well facility that conducts a well completion operation following hydraulic refracturing is not an affected facility, provided that the requirements of § 60.5375 are met. For purposes of this provision, the dates specified in § 60.5375(a) do not apply, and such facilities, as of the effective date of this rule, must meet the requirements of § 60.5375(a)(1)–(4).

(2) A well completion operation following hydraulic refracturing at a gas well facility not conducted pursuant to § 60.5375 is a modification to the gas well affected facility.

(3) Refracturing of a gas well facility does not affect the modification status of other equipment, process units, storage vessels, compressors, or pneumatic controllers located at the well site.

(4) Sources initially constructed after August 23, 2011, are considered affected sources regardless of this provision.

As a result of this provision, a modification of a well, defined as ''an onshore well drilled principally for production of natural gas,'' occurs when a well is refractured on or after the effective date of this rule, except when the owner or operator of a well controls emissions during the completion operation by the use, immediately upon flowback, of emission control techniques otherwise required for new wells, as discussed more below.[12]

Consistency With the Definition of Modification

This provision is consistent with the statutory definition of modification contained in CAA 111(a)(4).[13] As discussed in the proposal, CAA section 111(a)(4) defines a modification based on two requirements: (1) A physical change and (2) an emissions increase. The consistency of our approach with these two elements is discussed below.

Physical Change

Uncontrolled completion following refracturing of gas wells fits well within the statutory definition of modification (the refracturing results in a physical change which causes flowback and an increase in emissions relative to the emissions level prior to the refracturing). Accordingly, the NSPS' treatment of modification applies to completions of hydraulically refractured gas wells.

One commenter contends that recompletion does not constitute physical change even if there is re-perforation because it is an expected part of well operation. However, both the CAA and our regulation define modification to mean ''physical change'' without providing any qualification to that term, thus indicating that the term ''physical change'' is very broad to include any physical change. The commenter's interpretation of the term ''physical change'' is without support.

Emissions Increase

As a result of these physical changes, a multi-day period of flowback of natural gas, hydrocarbon condensate, water and sand is necessary to clean up the formation and wellbore prior to production of gas for sale. This flowback period is characterized by release of substantial amounts of VOC-containing natural gas and hydrocarbon condensate that would not have occurred absent the refracturing operation, thus meeting the second part of the statutory test—an increase in the amount of emissions.

As discussed in the proposal, EPA's data indicate that uncontrolled well completions with hydraulic refracturing consistently result in VOC emissions that were not present prior to such activities. Data in comments received also confirm that these uncontrolled

[10] At proposal, EPA used the term ''recompletion'' to describe completions of previously fractured new gas wells that are refractured at some future date, and we specified that such actions are considered modifications. In addition, we used the term ''recompletion'' to describe completions of existing wells (*i.e.*, those wells that were constructed before August 23, 2011) that subsequently are fractured for the first time or that are refractured.

[11] We disagree with the commenter. Fracturing and refracturing are not maintenance activities. On the contrary, these are essential processes that allow production of gas from shale and other formations, either during the initial development of a well or in development of new horizons within a previously fractured well. We also disagree with the characterization that we are regulating ''construction activities.'' Rather we are regulating the emissions resulting from the physical change.

[12] While we have not done so often, in situations such as this, where there is a defined set of physical changes that inevitably lead to an emissions increase, regulatory certainty and clarity can be provided by, as EPA is doing, providing a categorical listing of activities that constitute modifications. See, *e.g.*, 40 CFR 60.751 (addressing landfills; definition of modification); 40 CFR 60.100a(c) (addressing refineries; stayed pending reconsideration).

[13] We need not address if *New York* v. *EPA*, 443 F.3d 880, 890 (D.C. Cir. 2006) compels the result here. As we explain, in the body of this preamble our approach is consistent with CAA section 111(a)(4), and we provide a reasonable rationale for adopting the approach we take here.

refracturing activities result in significant VOC emissions. Our data indicate very low VOC emissions from gas wells (2.6 tpy on average) at the wellhead during ongoing production prior to such activities. In light of the above, we reasonably conclude that such activities result in an increase in the amount of VOC emissions and, therefore, constitute a modification.

We reject the comments suggesting that we should adopt the prior fracturing activity as the baseline for determining if an emission increase has occurred.[14] We note that these comments appear in part to rely upon a misunderstanding of the EPA's longstanding practice that the relevant baseline for determining an emissions increase under the NSPS is not based on the potential emissions profile associated with a prior physical change or the original construction but rather the emissions immediately prior to the physical change. See 57 FR 32314, 32330 (July 21, 1992) (explaining that, under CAA section 111(a), an emission increase is based on current potential emissions rather than original design capacity). Accordingly, under historical regulations, the proposed regulatory language and the final rule that "initial production volumes may have been higher than subsequent re-completions or refracturing operations because the formation has been depleted by production activities" does not mean that there would not be an emissions increase. Ongoing emissions during day-to-day production are very small and are not a function of well productivity, since these emissions originate from leaking valves and other components that do not leak more or less as production increases or declines. However, flowback emissions following refracturing are orders of magnitude greater than the production phase emissions.

Moreover, adoption of a prior fracturing activity as the baseline for comparison here is inappropriate. The purpose of the refracturing activity is to increase production from its current level. As explained above, at least for the short term, VOC emissions from the affected facility increase as a direct result of the physical change.[15] That is, these emissions would not have (and could not have) occurred without the physical change. Accordingly, we conclude that reliance on the prior fracturing activity as a baseline is inappropriate.[16]

De Minimis Exception

We recognize that there are reasons to limit the scope of the modification definition so as to not include certain well-controlled refracturing activities performed by sources. We recognize that the approach that we are taking in this final rule differs from the approach that we have taken in the past, as it excludes certain emission increases associated with a physical change from constituting a modification based on the *de minimis* exception. This exception allows agency flexibility in interpreting a statute to prevent "pointless expenditures of effort" and has been previously recognized by the United States Court of Appeals for the District of Columbia Circuit as an appropriate tool when interpreting the CAA section 111(a)(4) definition of modification in the context of New Source Review. *Alabama Power Co.* v. *Costle,* 636 F.2d 323, 360 (D.C. Cir. 1979).

Since the inception of the NSPS program, certain emission controls could be used by a source to avoid having an activity constitute a modification provided that the controls prevented emissions from increasing. As the District of Columbia Circuit explained:

> Under provisions of the regulations that are not challenged in this litigation, the operator of an existing facility can make any alterations he wishes in the facility without becoming subject to the NSPS as long as the level of emissions from the altered facility does not increase. Thus the level of emissions before alterations take place, rather than the strict NSPS, effectively defines the standard that an altered facility must meet.

Asarco Inc. v. *EPA,* 578 F.2d 319, 328–29 (D.C. Cir. 1978); see, also, 75 FR 54970, 54996 (September 9, 2010) ("However, sources always have the option of adding sufficient NO_X control to avoid an hourly emissions increase and avoid thus triggering the modification provision."). We have allowed such controls to permit the source to avoid being considered "modified" if the controls fully negate the emissions increase.

In this case, we are providing that where a source has in place, and, immediately upon flowback, applies emission controls equivalent to those required for a new source (as specified in 40 CFR 60.5375(a)(1) through (4)), the physical change will not constitute a modification despite the small remaining emission increase. Specifically, well completions conducted by sources for refractured wells and with the use, immediately upon flowback, of emission controls equivalent to those required for new sources will not be considered a modification, due to the *de minimis* increase in emissions of such wells using these controls. Several unique factors justify finding that application of the *de minimis* doctrine is appropriate here.

First, to qualify for the exclusion from the definition of modification the source must be using controls equivalent to those required were it to trigger the NSPS. As a result, the imposition of the NSPS would not yield additional regulatory or environmental benefits. See *Environmental Defense Fund, Inc.* v. *EPA,* 82 F.3d 451, 466 (D.C. Cir. 1996). Second, as a result of imposition of controls emissions are very low in magnitude. This is both with respect to the size of the increase associated with the physical change and the total emissions from the unit after the physical change. Third, the emissions associated with the change, and peak emissions post change, are time-limited. A well completion is a discrete activity, occurring over a 3–10-day period on an occasional basis, which may be as infrequent as once every 10 years. This is different from the type of emitting activity typically regulated as a modification under NSPS, which would involve ongoing emissions indefinitely into the future. Further, a source qualifying for this exception must comply with the recordkeeping and reporting requirements that are required of new sources. Accordingly, the increase in emissions from the physical

[14] One commenter relies on a passage from a proposed, but never finalized, rule preamble to argue that under the NSPS emission increase test prechange emissions are based on the highest level achievable in the 5 years immediately preceding a physical change. The passage, however, is not addressing the NSPS test generally applicable to modifications, but, rather, is addressing a specific regulatory provision applicable to modifications at electric utility steam generating units (EUSGU). See 70 FR 61081, 61089 (October 20, 2005). Specifically, the preamble discussion is describing 40 CFR 60.14(h), which states that a change at an EUSGU will not be a modification if "such change does not increase the maximum hourly emissions achievable at the unit during the five years prior to the change." See, also, 57 FR 32314, 32330 (July 21, 1992) (adopting 40 CFR 60.14(h) and contrasting the provision with the pre-existing test).

[15] Our data show that the magnitude of ongoing VOC emissions from a producing gas well is approximately 2.6 tpy or about 14 pounds per day, while the magnitude of VOC emissions is 23 tons over an average period of 7 days, or about 6,600 pounds per day, during a completion operation following refracturing. At this time, we do not have similar data on emissions from oil wells.

[16] One commenter claims that one cannot determine whether a given well completion activity qualifies as a modification based on the proposed definition because it is infeasible to measure the amount of flowback emission according to the EPA in proposing a work practice standard. However, nothing in CAA 111(a)(4) and 40 CFR 60.2 requires quantification of the amount of emission increase, only that there be an increase as a result of the physical change. In addition, the commenter's argument would appear to apply equally to any time we set a work practice.

change, and the total amount of additional emissions, will be very small.

We are providing the *de minimis* exception discussed above to provide states with flexibility in application of their permitting authority and resources. Commenters pointed out that a number of state permitting programs are triggered for sources that are subject to an NSPS as a result of a modification. The EPA recognizes that states are the most appropriate entities to determine whether and how sources should be permitted, and we have concern regarding potential impacts of this final rule on states' permitting resources. Accordingly, with this final rule, we intend that states retain the discretion to determine whether refracturing activities by sources employing control techniques that are required for new wells will require changes in that source's permit status.

Clarifying Changes

Although we are not finalizing the proposed definition of ''modification'' for the reasons discussed above, we believe it is important to address certain comments regarding the proposed definition in order to clarify the agency's intent as it relates to well completions. For example, we included ''natural gas'' in the proposed definition for ''modification'' in recognition that our proposed work practice requirements for well completions use natural gas as a surrogate for VOC. We consider natural gas to be an appropriate surrogate for VOC for well completion activities because our analyses of data on composition of natural gas at the wellhead indicated that emissions of natural gas during well completions contain various chemical species that are VOC. The inclusion of natural gas in the proposed definition for modification was not an indication that EPA was proposing natural gas as a pollutant to be regulated, as some commenters mistakenly thought.

We also received comment objecting to defining ''modification'' based on increase in the ''amount of emission'' instead of ''emission rate'' as provided in the General Provisions for modifications in 40 CFR 60.14. We had intended but were not clear in our proposed rule that the definition would apply only to well completions. In the final rule, we have promulgated the provisions discussed above regarding well provisions in lieu of the proposed definition for modification to clarify our intent.

Finally, this provision is intended to address comments suggesting confusion associated with our proposed definition of ''modification'' and the separate, proposed provision in 40 CFR 60.5420 that a workover is considered a modification. The second of these provisions is being removed in light of comments that there is no common understanding of this term and, as a result, it may be interpreted to cover more than the fracturing activities the EPA intended to cover.[17]

In summary, as a result of the comments and considerations discussed above, the final rule provides that well completions conducted on gas wells that are refractured on or after the effective date of this rule are modifications and are subject to the NSPS. However, gas wells that undergo completion following refracturing, with the use, immediately upon flowback, of emission control techniques otherwise required for new wells and that satisfy other requirements for gas well facilities, including notification, recordkeeping and reporting requirements, are not considered modified and, as a result, are not affected facilities under the NSPS. This provision is consistent with the NSPS program's history of allowing sources to use certain emission controls to avoid having an activity constitute a modification. In this situation, we consider it appropriate to require notification, recordkeeping and reporting requirements in order to ensure that a source is meeting the requirements to avail itself of this provision. We believe this approach will encourage early use of REC and will result in 1,000 to 1,500 REC that would not otherwise occur during the REC phase-in period ending January 1, 2015, discussed in section IX.B of this preamble.

2. Regulation of Methane and Other Pollutants

Comment: One commenter believes that under CAA section 111, the EPA must regulate each dangerous pollutant emitted by sources in the oil and gas source category in more than *de minimis* quantities for which controls are available and asserts that the EPA has failed to do so. In particular, the commenter states that the EPA must regulate methane, particulate matter (PM), hydrogen sulfide and nitrogen oxides (NO_X) from oil and gas operations. The commenter states that the EPA's explanation of why it declined to regulate certain pollutants does not discuss PM or hydrogen sulfide, address the most important sources of NO_X or offer a legal justification for its failure to regulate methane. The commenter interprets the CAA to mean that the EPA must, every 8 years, (1) review its standards (as it has done here), (2) determine whether it is ''appropriate'' to revise them, including whether it is appropriate to add additional pollutants to the standards, and (3) if so, revise them accordingly.

Response: In this rule, we are not taking final action with respect to regulation of methane. Rather, we intend to continue to evaluate the appropriateness of regulating methane with an eye toward taking additional steps if appropriate. On November 8, 2010, EPA finalized reporting requirements for the petroleum and natural gas industry under 40 CFR Part 98, the regulatory framework for the Greenhouse Gas Reporting Program (GHGRP). Beginning in September 2012, this program requires annual reporting of greenhouse gases (GHG) from large emissions sources and fuel suppliers in the United States. Petroleum and natural gas facilities will report annual methane and carbon dioxide (CO_2) emissions from equipment leaks and venting, and emissions of CO_2, methane and nitrous oxide from flaring, onshore production stationary and portable combustion emissions, and combustion emissions from stationary equipment involved in natural gas distribution. The EPA estimates that the rule will cover 85 percent of the total GHG emissions from the United States petroleum and natural gas industry with approximately 2,800 facilities reporting. The data submitted under the GHGRP will provide important information on the location and magnitude of GHG emissions from petroleum and natural gas systems and will allow petroleum and natural gas facilities to track their own emissions, compare them to similar facilities and aid in identifying cost-effective opportunities to reduce emissions in the future.

As noted in the proposal, the control measures that the EPA is requiring for VOC result in substantial methane reductions as a co-benefit. Over time, collection of data through the GHGRP and other sources will help EPA evaluate whether it is appropriate to directly regulate methane from the oil and gas sources covered by this rule. The EPA will be in a better position to characterize (1) the extent of methane emissions from these sources that will remain after imposition of controls

[17] We are not considering ''workovers'' to be modifications because: (1) They include truly routine activities; (2) in most instances we would anticipate only a small emissions increase, if any; and (3) we have no reason to think that these wells differ in emission profile or control options from non-fractured wells (or fractured wells after flow back), and accordingly we have not identified a BSER that would apply following any such modification.

required by this rule; and (2) whether additional measures are available and appropriate for addressing such emissions.

With regard to other pollutants, including PM, H_2S and NO_X, many of the sources of PM and NO_X within the Crude Oil and Natural Gas Production source category are within the scope of units covered by other NSPS and will be evaluated in the context of subsequent revisions of those rules, if appropriate. This approach is consistent with what the agency articulated when we promulgated the original oil and gas rules. See 49 FR 2637. For example, NSPS covering stationary reciprocating internal combustion engines (40 CFR part 60, subparts IIII and JJJJ) and combustion turbines (40 CFR part 60, subpart KKKK) regulate emissions of PM and NO_X from sources found in this category. These engines and turbines are found in a variety of locations in this category including gathering and boosting stations, natural gas processing plants and natural gas transmission and storage facilities. In addition, some mobile source regulations (40 CFR part 1039) cover nonroad engines such as those used on drilling rigs, electrical generators and hydraulic fracturing pumps. As we discussed at proposal (see 76 FR 52756) most, if not all, of the process heaters and boilers used in this category fall below applicability thresholds for EPA's boiler rules (40 CFR part 60, subparts Db and Dc). Although these smaller heaters and boilers are generally within the scope of this category, we received no quantitative data in the public comments on NO_X or PM emissions from these units. Given the broad coverage of the PM and NO_X sources in this category by other NSPS we did not depart from the approach adopted in 1984 of considering these pollutants in development of other standards.

Although the NSPS does not provide direct regulation of H_2S, the VOC control requirements in the final rule achieve reductions of H_2S a co-benefit in cases where H_2S is otherwise emitted in the oil and natural gas production segment. While amine treatment and sulfur recovery are routinely employed both upstream and at natural gas processing plants to remove H_2S from the natural gas stream, we believe that it would not be reasonable or cost-effective to require amine units and sulfur recovery for every emission point in the oil and natural gas production segment. We received no public comments suggesting other control technologies that could be applied to control H_2S in the field. Such emissions occur in the field as fugitive emissions at the wellhead and vented emissions from well completions, storage vessels, pneumatic controllers and compressors. However, as mentioned above, the VOC control measures provided in the final rule for well completions, storage vessels, pneumatic controllers and compressors greatly reduce any H_2S emissions along with the VOC emissions controlled.

3. Expanded Scope of the Source Category

Comment: One commenter states that, in the preamble, the EPA makes reference to its proposal to significantly expand the scope of oil and gas operations that would be covered by the new NSPS, and states that "[t]o the extent that there are oil and gas operations not covered by the currently listed Oil and Natural Gas source category, pursuant to CAA section 111(b) we hereby modify the category list to include all operations in the oil and natural gas sector" (citing 76 FR 52745, August 23, 2011). The commenter is not aware of any authority pursuant to which the EPA may affect a significant expansion of the category list merely through the language of the preamble in an NSPS rulemaking. The commenter states that, in a related context, the CAA requires that the EPA engage in consultation with state governors and air pollution control agencies, suggesting that more than a preamble reference is needed in order to expand the category list and impose NSPS requirements on the new and unique affected sources addressed in this rule. See 42 U.S.C. 7411(f)(3). The commenter asserts that the sources the EPA seeks to regulate are different types of stationary sources than gas processing plant, and contends that oil and gas production wells are stationary sources, but are, clearly, not processing plants.

Response: Because EPA has concluded that the currently listed Oil and Natural Gas source category covers at least those operations in this industry for which we are finalizing standards, we need not address what steps the agency must take if expanding a source category.[18] As we explained in the preamble to the proposed rule, when the EPA initially listed this source category, it did so in a document where it described its listings as broad. 76 FR at 52745.[19] Contrary to commenters assertions, the EPA has viewed this source category listing very broadly. Specifically, when promulgating the first sets of standards of performance for this source category, we stated that the source category "encompass[es] the operations of exploring for crude oil and natural gas products, *drilling for these products, removing them from beneath the earth's surface,* and processing these products from oil and gas fields for distribution to petroleum refineries and gas pipelines." 49 FR at 2637 (emphasis added). That preamble linked the endangerment finding under CAA section 111(a) to the industry as a whole: "The crude oil and natural gas production *industry* causes or contributes significantly to air pollution that may reasonably be anticipated to endanger public health or welfare" (*Emphasis added*). 49 FR 2636. The statements above affirm our conclusion that the currently listed Oil and Natural Gas source category covers all operations for which we are setting standards. That the original NSPS's only set standards for a limited set of sources within the category cannot be taken to imply that other units were not within the scope of this original listing. See, *e.g., Nat'l Lime Ass'n* v. *EPA,* 627 F.2d at 426 n. 27 (noting that the EPA set standards for only certain kiln types within the source category). Indeed, the preamble to the 1984 proposed NSPS rule directly addresses regulation of wells, concluding that the agency was not setting standards at that time; not because they were outside the scope of the source category, but because the agency was unable at that time to identify "[b]est demonstrated control technology." 49 FR at 2637. As all of the units that we are regulating fall within the scope of the original listing, we need not address what steps would be necessary were we to expand the scope of the listing.

B. Major Comments Concerning Well Completions

1. Applicability and Exemptions

a. Well Exemptions

Comment: One commenter suggests adding "appraisal wells" as a third subcategory of well to be exempt from the REC requirements, and defines these wells as those drilled in an area where the reservoir has not been classified for that area as containing proved reserves of natural gas. According to the commenter, adding this definition and exemption better reflects the universe of wells for which a gas flow line system

[18] For the same reason, we need not address the comment claiming that CAA section 111(f)(3) requires that the EPA consult with state governors before amending CAA section 111(b) listing.

[19] While not required to do so, we have included the Background Information Document for the listing rule in the docket for this rule. We note that those documents shed no additional light on the scope of the listing beyond our interpretation of the listing preamble described in the proposed rule.

will not be available. The commenter adds that it also avoids a potential problem where a shale play appraisal well system is effectively compelled to install a flow line system before the wells are determined to be economically viable, in order to assure compliance with 40 CFR part 60, subpart OOOO.

Response: The EPA recognizes that a flow line at the well pad is a necessary precondition to capture flowback gas for emissions control so that the REC process has an outlet for the captured gas. However, the EPA does not agree that appraisal wells need to be exempt. Appraisal wells are drilled and then logged to assess productivity. If well logs indicate that the well is productive, then fracturing will be performed, and the cost to fracture, complete and produce the well, including installing a flow line, will be incurred. If the well logs indicate the well is not economically productive, then no fracturing occurs and the NSPS does not apply. The EPA, therefore, believes it is reasonable to require appraisal wells that are hydraulically fractured to comply with Subcategory 3 rule requirements.

b. Threshold for Low Pressure (Low Volume) Gas Wells and Wells with Low or No VOC Emissions

Comment: One commenter expresses support for the REC requirements and urges the EPA to limit the number of well completions exempted from the requirements as much as possible. Several commenters contend that not all well completions can be conducted successfully under a requirement to flow back to the flow line, since the imposition of the flow line backpressure may reduce the flowback gas velocity sufficiently so that it is not energetic enough to clean up the well of liquid and sand. One commenter recommends that any well whose reservoir pressure (measured at the wellhead immediately after perforation) is less than 4 times (in absolute units) the line pressure measured at the flow meter, would be exempt from any requirement to flow to sales during the flowback period. According to the commenter, variability in reservoir and line pressures across the United States makes setting a specific pressure threshold difficult.

Response: The EPA has established three subcategories of wells in response to public comments, as described above. One of those categories comprises non-wildcat and non-delineation low pressure gas wells. Low pressure gas wells are defined as wells with reservoir pressure and vertical well depth such that 0.445 times static reservoir pressure (in pounds per square inch absolute (psia)) minus 0.038 times the vertical well depth (in feet) minus 67.578 psia is less than the flow line pressure at the sales meter. Thus, wells above this pressure differential must implement REC, while wells below this pressure differential are required to route emissions to a completion combustion device.

The EPA solicited comment in the proposed rule on situations where REC may be infeasible and criteria and thresholds for distinguishing well completion operations in those situations from others where REC is feasible. As noted above, several commenters highlighted the technical issues that prevent an operator from implementing an REC on a low pressure gas well, which is the inability to attain a gas velocity sufficient to clean up the well when flowing against the flow line backpressure. Based on this information, the EPA agrees that a pressure differential threshold is reasonable and addresses the technical limitations of low pressure gas wells to produce to the flow line during completion.

As noted above, a commenter recommended specific approaches to developing a pressure threshold, including specifying that any well whose reservoir pressure is less than 4 times (in absolute units) the line pressure measured at the flow meter would be exempt from any requirement to flow to the flow line during the flowback period. This recommendation is based on a flowing bottom hole to reservoir pressure ratio of 1:2 and a line pressure to flowing bottom hole pressure of 1:2. The EPA concurs with the commenter that flowing bottom hole pressure can be represented as half of the reservoir pressure for this rule. The EPA disagrees with the commenter that line pressure can be represented as half of the flowing bottom hole pressure for this rule since this pressure relationship can be more accurately determined using the Turner equation for liquids unloading from a well paired with models relating fluid velocity to pressure drop. Therefore, the EPA has modeled a worst-case pressure drop factor between the line pressure and flowing bottom hole pressure and has established a pressure threshold using this factor and the 1:2 factor for flowing bottom hole pressure to reservoir pressure. The result of this modeling is the equation discussed above in the definition of low pressure gas wells.

As discussed in the proposal preamble, potential control options are REC with combustion or a completion combustion device alone. Because REC may not always be technically feasible for wells that fall below the pressure threshold, the EPA has determined that the BSER for reducing VOC emissions for this subcategory of wells is a completion combustion control device. However, the EPA encourages the use of REC with combustion should that be a viable option for any well within this subcategory. Therefore, in the final rule, for non-wildcat and non-delineation wells with a pressure drop below the differential described above, the EPA requires the use of either a completion combustion device or REC with combustion to control gas not suitable for entering the flow line.

Comment: Several commenters address parameters for defining which well completions would be subject to REC requirements. Commenters request that the EPA exempt wells with low VOC concentrations from the REC requirements and not issue the proposed standards before reconsidering the emissions estimates. One commenter suggests that the EPA exempt hydraulically fractured natural gas horizontal wells with *de minimis* VOC concentrations because the cost per ton of VOC reductions is extremely high for these wells and the emissions from the combustion of the produced gas could worsen ozone formation in the area. Commenters also provide, as examples, some wells with low or no VOC as support for exempting wells with a low VOC content or for exempting certain classes of wells such as coal bed methane. Several commenters contend that coal bed methane wells have low VOC, while several other commenters contend that coal bed methane wells have no VOC. Some commenters provide examples of coal bed methane wells with low VOC or no VOC, and one commenter provides an example of a shale gas well with no VOC.

Response: The EPA acknowledges that the VOC concentration in natural gas can vary across wells and reservoir types such as coal bed methane (CBM), shale and tight sands. However, the information provided in the comment is insufficient for the EPA to determine that any specific class of wells, or wells with VOC concentration below a specific threshold, would not be cost-effective to regulate, as the commenters recommend. For example, several commenters contend that CBM wells have low or no emissions. In response to comments received, the EPA assessed the VOC content of CBM wells, including a review of the gas composition data presented in the gas

composition memo[20] available in the docket and in an article[21] by the United States Geological Survey. The VOC concentrations among CBM wells will vary and are not always low. The limited CBM data submitted by the commenter, while suggesting low-VOC concentrations at some CBM wells, is not to the contrary. Accordingly, we conclude that it would be inappropriate to provide a categorical exclusion for such wells.

We also have determined that providing a low-VOC concentration exclusion would be inappropriate, both because the submitted data do not support such an exclusion (they do not demonstrate that such circumstances are frequent) and because of implementation concerns. Specifically, even if such a VOC concentration threshold described above can be determined, to ensure compliance with the rule, an operator would have to determine with certainty before production, whether a particular well was going to be above or below the threshold in order to mobilize the necessary capture equipment and secure a flow line, etc. This would require the operator to determine the reservoir composition, *e.g.,* the gas composition prior to separation, in advance of the well completion (*i.e.,* the determination of whether the well would be subject to the NSPS would have to be performed before the information on which to base such a determination would be available). Although nearby existing wells could potentially provide some indication of the general VOC content of the gas from the future well in question, there would be no assurance of certainty. In addition, the operator would need to certify that the reservoir sample is going to stay consistent and representative of the gas stream throughout the full completion process through multiple gas composition analyses.

Taking into account the variability in VOC concentrations across reservoir types, the EPA's cost analysis illustrates that these requirements are cost-effective, especially when taking into account the gas savings. Compliance with a VOC concentration threshold-based rule for well completions could actually increase the burden to the operator by requiring numerous compositional analyses to demonstrate compliance with the rule.

c. Definition of Gas Well

Comment: Several commenters mentioned that the proposed definition of "gas well" was unclear due to the term "principal production" used in describing what the well produces. One commenter requests that the definition of gas well be modified to be each respective state's definition of gas well. The commenter states that, by doing this, the EPA would eliminate any confusion associated with having to apply different criteria (NSPS versus state regulations) for how to define a well-type in assessing the applicability of the rule.

Response: In response to comments requesting further clarity in the definition, the EPA has revised the definition. The proposed definition was "*Gas well* means an onshore well, the principal production of which at the mouth of the well is gas." In the final rule, in response to the comments we received, the EPA has revised the definition to exclude the phrase "at the mouth of the well is gas." Based on this revision, the definition for the final rule is "*Gas well or natural gas well* means an onshore well drilled principally for production of natural gas."

EPA's intent in setting standards for completion of hydraulically fractured gas wells is to require reduced emissions completions for wells where infrastructure is generally present to get recovered natural gas to market. Our understanding is that owners and operators plan their operations to extract a target product and evaluate whether the appropriate infrastructure is available to ensure their product has a viable path to market before completing a well. We expect that the final rule will result in control of hydraulically fractured gas wells drilled in the four formation types generally accepted as gas-producing formations: (1) High-permeability gas, (2) shale gas, (3) other tight reservoir rock or (4) coal seam. We believe that the wording changes made to the definition of "gas well" clarify the intent so that implementing agencies and industry will not be burdened with complex applicability determinations.

With respect to using State gas well definitions, basing applicability on different definitions from State to State could introduce inconsistencies that are counter to the goal of nationwide regulation. We believe the NSPS, being a national rule, should contain a single definition applicable nationwide. However, states may choose to use a definition more expansive than our definition for their programs.

Comment: One commenter states that, based on the EPA's discussion in Section 4 of the Technical Support Document (TSD), it appears the EPA's intent is to require reduced emissions completions only for natural gas wells. The commenter supports that the EPA applied reduced emissions completions only to natural gas wellhead facilities and excluded oil wellhead facilities and other types of gas wells which have little or no VOC emissions. The commenter states that, as shown on page 4–13 on Table 4.4, *Nationwide Baseline Emissions from Uncontrolled Oil and Gas Well Completions and Recompletions,* of the TSD, there are only 134 tpy of VOC emissions from oil well completions and recompletions for the entire United States, which is not worth regulating.

One commenter recommends the following revision: "Gas well means a well, the principal production of which at the mouth of the well is [add: hydrocarbon gas, not CO_2] * * * Well means an oil or gas well, a hole drilled for the purpose of producing oil or gas, or a well into which fluids are injected." One commenter proposes the following revision: "Gas well means a well, [DELETE the principal production of which at the mouth of the well is gas] completed for production of natural gas from one or more gas zones or reservoirs. Such wells contain no completions for the production of crude oil." The commenter also proposes the following revision: "Gas well means a well [STRIKETHROUGH: the principal production of which at the mouth of the well is gas.] [ADD TEXT: completed for production of natural gas from one or more gas zones or reservoirs. Such wells contain no completions for the production of crude oil.]"

Response: Although some wells drilled in crude oil formations may produce associated gas along with the oil, without a gas infrastructure present, the EPA does not have sufficient data on VOC emissions during completion of hydraulically fractured oil wells to set standards for these operations at this time.[22] As a result, the final rule will not affect drilling of oil wells.

[20] Memorandum from Brown, Heather, EC/R Inc., to Moore, Bruce, EPA/OAQPS/SPPD, *Composition of Natural Gas for use in the Oil and Natural Gas Sector Rulemaking,* July 28, 2011. Docket ID No. EPA–HQ–OAR–2010–0505–0084.

[21] Rice, Dudley, *Composition and Origins of Coalbed Gas,* U.S. Geological Survey, Denver, Colorado.

[22] In the proposed rule, we briefly assessed well completions of hydraulically fractured oil wells and did not believe that either REC or a completion combustion device is cost effective for reducing VOC emissions from such operations. We note, however, that this brief assessment of oil wells in the proposed rule was based on limited information at the time and that more information is needed for us to fully evaluate the VOC emissions and control options for these operations.

d. Availability of Infrastructure to Convey Gas to Market

Comment: Various commenters have asserted that, in some cases, REC cannot be performed on some wells because there is no gathering line available to convey gas produced during the completion flowback period.

Response: As explained above, it is our understanding that owners and operators plan their operations to extract a target product and evaluate whether the appropriate infrastructure access is available to ensure their product has a viable path to market before completing a well. However, in the standards for gas well affected facilities, the provisions of 40 CFR 60.5375(a)(1) through (4) apply to all fractured gas wells that are not exploratory wells, delineation wells or low pressure wells. These standards require that the well completion flowback be conducted using a combination of collection (*i.e.,* REC), combustion and venting, depending on the characteristics of the flowback material and feasibility of routing the gas to a collection system to be conveyed to market. Section 60.5375(a)(3) provides:

"You must capture and direct flowback emissions that cannot be directed to the flow line to a completion combustion device * * *".

We believe that owners and operators of gas wells subject to 40 CFR 60.5375(a) that require REC for a portion of the flowback period will exercise due diligence in coordinating the completion event with availability of a flow line to convey captured gas to market. However, there may be cases in which, for some reason, the well is completed and flowback occurs without suitable flow line available. In those isolated cases, we believe 40 CFR 60.5375(a)(3) provides for gas not being collected and instead combusted or vented pursuant to that section.

e. Fracturing of Wells Using Nitrogen and Carbon Dioxide

Comment: One commenter suggested that wells that are fractured using nitrogen or CO_2 should be exempt from the NSPS but did not provide supporting rationale. Other commenters expressed concern that inert gases such as nitrogen are not flammable, making compliance with the combustion provisions of the NSPS impossible.

Response: We believe that the standards for well completions adequately address the concerns expressed by operators using nitrogen and/or CO_2 for fracturing. We provided in the proposed rule, and further clarified in the final rule, that these standards require that the well completion flowback be conducted using a combination of collection (*i.e.,* REC), combustion and venting, depending on the characteristics (including flammability) of the flowback material and feasibility of routing the gas to a collection system to be conveyed to market. Both the proposed and final rules express our intent to require REC only where there is salable quality gas to the gather line. See 76 FR 52800 and 40 CFR 60.5375(a)(2) of the final rule.

Section 60.5375(a)(3) in the final rule provides: "you must capture and direct flowback emissions that cannot be directed to the flow line to a completion combustion device, except in conditions that may result in a fire hazard or explosion, or where high heat emissions from a completion combustion device may negatively impact tundra, permafrost or waterways. Completion combustion devices must be equipped with a reliable continuous ignition source over the duration of flowback."

Under this provision, operators who employ energized fracturing using inert gases and cannot route the flowback gas to a collection system because of poor gas quality must direct the flowback to a completion combustion device with a continuous ignition source. Although part of the flowback gases directed to the combustion device would not be flammable, the ignition source will ignite the flammable portion of the flowback, including VOC. Therefore, the presence of inert gases such as nitrogen and CO_2 in the flowback gas has no bearing on the VOC reduction we expect to achieve through the NSPS or on compliance with provisions of the final rule.

2. Rule Should Not Prescribe Equipment

Comment: Several commenters suggest revising 40 CFR 60.5375(a)(2) equipment requirements to be less prescriptive, especially in cases where use of specified or all listed equipment may not be necessary, and to provide flexibility to include newly developing technology. Other commenters assert that language in 40 CFR 60.5375(a)(1) and (2) stating that source owners or operators should "minimize the emissions associated with venting of hydrocarbon fluids and gas" and that "[a]ll salable gas must be routed to the gas gathering line as soon as practicable" is vague and recommended a requirement that facility owners follow a Best Management Practice (BMP) plan that the EPA could develop, informed by the Natural Gas STAR program.

Response: The EPA agrees that prescribing specific equipment to accomplish a reduced emissions completion is not necessary and has revised the rule language to not prescribe specific equipment. The operational standards provided in the NSPS allow the operator flexibility to perform the REC using equipment and practices best determined by the operator. As a result, we believe that a BMP plan developed by the EPA would not provide a higher degree of emissions control and could hinder innovation.

3. Availability of Equipment and Trained Personnel

Comment: Commenters state that the supply of REC equipment and personnel is insufficient to meet the requirements of the proposed rule, applied nationally. According to commenters, proper surface equipment, collection infrastructure and qualified personnel are not readily available; they assert that this equipment is fairly specialized, the shops licensed to make it are limited and some of the components require a long lead time. For these reasons, commenters indicate that compliance by the issuance date of the rule would be unrealistic and that the EPA should provide a longer compliance period.

Response: Based on information submitted by commenters, we have reason to believe that, currently, there is already significant demand for REC equipment. For example, Colorado, Wyoming, the City of Fort Worth, Texas, and the City of Southlake, Texas, require REC under certain conditions. Additionally, public comments, reports to the EPA's Natural Gas STAR Program and press statements from companies indicate that some producers implement REC voluntarily, based upon economic and environmental objectives. If REC were to be immediately required of all well completions, NSPS would place significant additional demands on REC equipment supply and experienced personnel.

As the near-term supply of REC equipment and trained personnel will be insufficient to meet the new national demand for equipment and labor, immediate compliance with the REC requirements could be impossible, potentially causing producers to delay well completions until appropriate equipment and labor are available. Resulting delays in well completions while awaiting equipment availability could cause a decrease in the nationwide natural gas supply and would drive up the cost of completions doing REC. It is not the EPA's intent to set in motion a series of events through this rule that has the potential to affect

the natural gas supply and increased cost of REC would undermine our BSER analysis. Accordingly, it is important that the EPA consider the availability of REC equipment and personnel in its BSER analysis.

Through EPA and industry events and collaborative studies, the EPA has interacted with operating companies that have extensive experience implementing REC. In particular, the EPA developed a detailed study [23] on REC in collaboration with service providers. Based on this experience, the EPA has gained extensive information on this technology. Despite these efforts, the EPA is not aware of any quantitative information on the current and future supply of workers trained in REC techniques.

The EPA received data on the current and future supply of REC equipment. According to one commenter, about 300 REC units are in use today, with the ability to process about 4,000 wells per year, and 1,300 additional units would be required to perform 20,000 REC per year. About 1,600 units performing 20,000 REC/year implies a REC productivity rate of about 12.5 REC/year/unit, or roughly each unit performing one REC per month, on average.

The NSPS proposal estimated 9,300 REC performed for new natural gas well completions and 12,200 REC performed for existing natural gas well completions following refracturing would be required, in addition to those already required by state regulations. In the analysis supporting the final rule, the EPA revised estimates show 11,403 hydraulically fractured and 1,417 hydraulically refractured natural gas well completions will be performed in a representative year, which includes completions in states which currently have REC requirements. The revised estimate also reflects a change in the refracture frequency of existing wells from 10 percent to 1 percent based on information provided by commenters. Of the total hydraulically fractured well completions, the EPA estimates that about 11,300 REC will be required nationally on the basis of the final rule's provisions for wildcat (exploratory) and delineation wells, flowback gas pressure and natural gas well completions conducted on existing gas wells that are subsequently fractured or refractured. This estimate excludes REC required by state regulations.

Assuming a REC unit performs 12.5 REC/year, as is asserted by the commenter, about 900 units would be required. This implies a current shortfall of about 600 units, based upon the numbers and assumptions provided by the commenter. The commenter states that industry can deliver about 50 units per quarter, after a 1-year build-up period. Given that the EPA does not have an alternative estimate of the number of REC units industry can produce per year, we adopt the estimate of 50 units per quarter for this analysis, although the EPA disagrees with the assumption that a 1-year build-up period is required. Using the commenter's assumptions, it would take about 4.25 years to meet demand. This scenario is depicted in Scenario A in Table 6 below, assuming compliance is initiated at the beginning of the second quarter, 2012, and the industry begins delivering 50 units per quarter roughly 1 year after the compliance date.

Surveys conducted by one commenter indicate that nine companies expect to perform more REC than the current stock is capable of. Given this growing demand, it is reasonable to assume industry can deliver units during the build-up period of the first year of implementation, which would reduce the time required to meet full demand another year to a total of about 3.25 years (Scenario B).

The EPA also assessed whether the productivity of equipment in use could be higher than the 12.5 REC/year/unit derived from the comment, and the potential impact of such increase on the equipment supply. The EPA estimated that flowback periods will typically be 3 to 10 days with 7 being a reasonable average. Therefore, because it is likely that a REC unit could be moved to another well site and be in operation in less than 20 to 27 days, it is reasonable to conclude that each REC unit can perform more than 12.5 REC/year.

If the utilization rate of REC units is increased gradually from performing 12.5 REC/year/unit to 14 to 18 REC/year/unit, the time required to build the supply of REC units decreases (Scenarios C–G). As Table 6 shows, each 1 REC/year/unit increase reduces the build-up time by about 1 quarter. As is shown in Scenarios C and G, increasing the utilization rate of REC to 14 to 18 REC/unit/year with industry supplying new units beginning with the compliance date would provide between 1.75 and 2.75 years for full build-out of the REC unit supply by the beginning of calendar year 2015.

TABLE 6—REC UNIT SUPPLY ANALYSIS

Scenario	A	B	C	D	E	F	G
RECs Required	11,301	11,301	11,301	11,301	11,301	11,301	11,301
RECs/year/unit	12.5	12.5	14.0	15.0	16.0	17.0	18.0
Units Needed	904	904	807	753	706	665	628
Stock in Existence (assume industry can build 50 units/quarter; assuming industry starts with 300 units); compliance begins approximately at the end of the second quarter, 2012.							
2012 (Q1)	300	300	300	300	300	300	300
2012 (Q2)	300	300	300	300	300	300	300
2012 (Q3)	300	350	350	350	350	350	350
2012 (Q4)	300	400	400	400	400	400	400
2013 (Q1)	300	450	450	450	450	450	450
2013 (Q2)	300	500	500	500	500	500	500
2013 (Q3)	350	550	550	550	550	550	550
2013 (Q4)	400	600	600	600	600	600	600
2014 (Q1)	450	650	650	650	650	650	650
2014 (Q2)	500	700	700	700	700	700	.....
2014 (Q3)	550	750	750	750	750	.....	.....
2014 (Q4)	600	800	800	800	.....	.....	.....
2015 (Q1)	650	850	850	.....	.....	.....	.....

[23] Available at: *http://www.epa.gov/gasstar/documents/reduced_emissions_completions.pdf*.

TABLE 6—REC UNIT SUPPLY ANALYSIS—Continued

Scenario	A	B	C	D	E	F	G
2015 (Q2)	700	900					
2015 (Q3)	750	950					
2015 (Q4)	800						
2016 (Q1)	850						
2016 (Q2)	900						
2014 (Q3)	950						

Because of uncertainties in the supply of equipment and labor over the near-term, and based on our analysis described above, the EPA concludes that REC may not always be available through 2014. Therefore, during this period, the BSER for well completions is to combust completion emissions. REC with combustion as an alternative to combustion is permitted by the rule so that facilities that are able to obtain REC equipment may still capture completion emissions using a REC. After January 1, 2015, capturing completion emissions using a REC will be considered BSER. This period will permit the companies producing REC units to increase production to levels sufficient to meet new demand. In addition, because more REC will be performed as a result of this rule, the EPA believes that producers will take advantage of scale economies and use REC units at a higher rate of productivity than the rate implied by comments received.

The EPA believes that the NSPS, as finalized, will minimize the risks of producers slowing well completion-related activities to obtain appropriate equipment and labor. While there would be NO_X formation as a result from the additional combustion of completion emissions during the phase-in period, VOC emissions reductions would be maintained because completion emissions will be either combusted or captured. The EPA maintains that the benefit of the VOC reduction during the phase-in period far outweighs the secondary impact of NO_X formation during pit flaring. The phase-in period would also minimize the possibility that the cost of REC equipment and labor increases over the near-term, enabling producers to better plan efficient use of existing and new capital and labor, and providing additional time for innovation in REC technologies and/or practices. We believe this period provides ample time for this technology to be built and available for use.

At the same time, for wells undergoing recompletions during the period prior to January 1, 2015, the terms of 40 CFR 60.5365(h), which specify that "[a] gas well facility that conducts a well completion operation following hydraulic refracturing is not an affected facility, provided that the requirements of section 60.5375 are met," may provide an additional incentive for producers to use REC units prior to January 1, 2015, if they can obtain appropriate equipment and labor. Also, considering the requirement in some states that any source subject to a federal NSPS must get a state minor source air permit, we anticipate that the desire to avoid even short term delays caused by state permitting, as well as the associated costs, will serve as an incentive for the use of REC during well completion operation following hydraulic refracturing, including operations prior to January 1, 2015. Furthermore, as January 1, 2015, approaches it is highly likely that providers of REC equipment and related services will be increasing availability of such equipment and services in ways that benefit supply and price. For these reasons, the EPA anticipates that during the period between promulgation and January 1, 2015, between 1,000 and 1,500 wells will be recompleted with REC units, notwithstanding the requirements of 40 CFR 60.5375(a) and the combustion option they provide.

4. Cost and Emissions Calculations

Comment: Some commenters request the EPA to fully explain or reconsider the 10-percent rate of refracturing of wells.

Response: In response to comment, the EPA has reevaluated the assumption that, on average, each fractured gas well is re-fractured every 10 years, which equates to approximately 10 percent of fractured gas wells being re-fractured each year, based on drilling and re-fracture records from an industry representative. Based on its review of the comment, including references noted in the comment and other information available to the agency, the EPA concluded that it had overestimated the re-fracturing frequency. The information reviewed by the EPA, which, altogether, represent over 20,000 gas wells over multiple years, some as far back as 2000, indicate that the annual recompletion frequency can be as low as 0.1 percent and as high as 0.8 percent. Based on this information, the EPA has revised its estimate of re-fracturing frequency from 10 percent to 1 percent of fractured gas wells per year. The EPA rounded the figures provided by the companies to reflect the uncertainty in the data.

5. Definition of Affected Facility

Comment: Several commenters assert that a well completion is different from a well workover and should be better defined in the rule.

Response: Based on the comments received, the EPA acknowledges that the term "workover" is a general term that may have a number of different meanings. Based on the various definitions of the term provided by the commenters, we realize that workover may be interpreted to include routine maintenance activities that we did not intend to cover under the rule and which result in no increase in emissions. Therefore, in the final rule we have revised the definition of "well completion operation" to exclude the term "workover" and, instead, include the phrase "with hydraulic fracturing."

C. Major Comments Concerning Pneumatic Controllers

1. Definition of Affected Facility

Comment: Some commenters request that the EPA consider excluding or exempting emergency and/or safety system devices (such as a pilot operated pressure relief valve). According to one commenter, safety system devices typically do not emit gas unless there is an emergency, have a near-zero VOC-level static state and, if regulated, could be replaced by substandard, cheaper technology of spring operated valves which would create much more leakage of gas into the environment.

With regard to emergency situations, another commenter argues that the proposed standards that apply to pneumatic controller affected facilities (40 CFR 60.5390(b)) could inhibit safe plant operation during an emergency because they require that each pneumatic controller located at a natural gas processing plant have zero

natural gas emissions. According to the commenter, a gas-powered controller is a reliable alternative for safe plant operation during emergencies, and the commenter suggests that the final rule include an exception to allow gas plants to use natural gas-driven pneumatic controllers for emergency plant shutdown and subsequent startup.

With regard to high-bleed pneumatic controllers, several commenters request that the EPA further explain when the use of high-bleed pneumatic controllers is allowed and provide specific examples of exemptions. The commenters suggest exemptions that address situations such as those where the natural gas includes impurities that could increase the likelihood of fouling a low-bleed pneumatic controller, such as paraffin or salts; where weather conditions could degrade pneumatic controller performance; during emergency conditions; where flow is not sufficient for low-bleed pneumatic controllers; where electricity is not available; and where engineering judgment recommends their use to maintain safety, reliability or efficiency. Several commenters request that the EPA provide additional information about how to demonstrate that the use of high-bleed pneumatic controllers is predicated, as stated in proposed 40 CFR 60.5390(a). The commenters suggest that this exemption is very vague, will allow for excessive emissions and is not enforceable.

Response: The EPA included in the proposed rule exemptions from the NSPS to allow the use of a controller with a natural gas bleed rate greater than 6 scfh due to functional needs. These exemptions include, but are not limited to, response time, safety and actuation of valves. These functional exemptions to the requirement address the commenters' concerns of safety, emergency and otherwise non-routine situations that require the use of a controller with a natural gas bleed rate greater than 6 scfh. In response to comments regarding vagueness of the proposed exemption, the EPA revised this exemption provision in the final rule. We believe the provision in the final rule clarifies the scope of this exemption.

Comment: Several commenters express concerns with the proposed rule's treatment of various types of pneumatic devices and controllers. One commenter requests that the EPA clarify in 40 CFR part 60, subpart OOOO that intermittent bleed pneumatic devices are not affected sources. Another commenter asserts that continuous low-bleed controllers that replace existing continuous low-bleed controllers should not be "affected facilities." According to this commenter, some designed high-bleed devices may be isolated from the gas pressure with a valve and operated manually on an intermittent basis. The commenter wants clarification in the rule that will allow an operator to use a high-bleed device if it is operated in a manner that keeps its emission levels less than 6 scfh.

One commenter requests that the EPA clarify in the final rule that the distribution segment and self-contained devices that release gas to a downstream pipeline instead of to the atmosphere are exempt. Another commenter argues that no-bleed pneumatic devices have zero emissions and, thus, should not be included in the proposed rule.

One commenter discusses the use of solar-powered controllers, fuel-cell powered controllers and mechanically-controlled devices in remote locations as an alternative to natural gas where grid electricity is not available. This commenter also recommends that the EPA set a zero emissions standard based upon no-bleed devices wherever electricity (either from a grid or from field power sources) is available within a reasonable distance from the facility and suggests that the EPA could establish an exemption to no-bleed devices where low-bleed devices are necessary because no-bleed devices cannot be feasibly installed.

Another commenter states the definition of "pneumatic controller" is unclear and should be revised.

Response: In the final rule, the EPA has revised the definition of "affected facility" for pneumatic controllers in the production segment [24] to address a number of the comments described above. Specifically, for pneumatic controllers at gas processing plants where the standard is zero bleed rate, we have defined the affected facility as a continuous bleed natural gas-driven pneumatic controller. For other areas in the production segment (*i.e.,* excluding gas processing plants), where the standard is a bleed rate of 6 scfh or less, we have defined the affected facility as a continuous bleed natural gas-driven pneumatic controller operating at a bleed rate greater than 6 scfh. By defining the pneumatic controllers affected facilities to be continuous bleed and gas-driven, we clarify that the NSPS does not apply to intermittent bleed devices, no-bleed pneumatic devices (by design), self-contained devices and devices driven by instrument air. The revised definitions also exclude from the NSPS coverage owners and operators who are already using (including replacement) pneumatic controllers that meet the applicable standards, thus, relieving them from the cost and other burdens related to compliance.

Regarding the comments related to solar-powered controllers, fuel-cell powered controllers, mechanically-controlled devices and no-bleed devices wherever electricity is available, we considered these types of devices in the BSER analysis, as discussed in the TSD. Any such controller system would require a backup system (consisting of at least an electrical generator) to operate the controllers when the primary system was inoperable. When considering the cost of the backup system, these options were not cost-effective. We, therefore, do not believe that they are BSER for reducing VOC emissions from pneumatic controllers where grid electricity is not available. We also decline to set a zero emission standard "wherever electricity * * * is available within a reasonable distance," as a commenter suggests. We have no information, nor has the commenter provided any, on how to determine the suggested "reasonable distance."

Comment: Several commenters request an exemption for all affected facilities handling gas with less than 10-percent VOC content by weight. Some commenters offer suggestions for such exemption, such as requiring recordkeeping of the gas VOC content in order for a facility to maintain the exemption.

One commenter believes that the EPA should delete the pneumatic controller requirements because most of the gas emitted is methane, and there is little VOC emission reduction benefit. Another commenter suggests limiting applicability to pneumatic controllers at natural gas processing plants or upstream of processing that exceeds a defined VOC threshold.

Several commenters opine that pneumatic device definitions and applicability should be based on VOC emissions, not natural gas as a surrogate. Commenters assert that the 6 scfh high-bleed/low-bleed threshold value is unsupported, that natural gas VOC content varies widely and that, in most cases, unconventionally produced CBM and shale gas have little, if any, measurable VOC.

Several commenters also wanted to exclude pneumatic controllers driven by a specified percentage of VOC.

[24] The NSPS does not cover pneumatic controllers in the distribution segment. The EPA did not address those controllers in the proposed rule. Although the EPA had proposed standards for pneumatic controllers in the transmission and storage segment, for reasons explained in section IX.C.2 of this preamble, the EPA did not include such standards in the final rule.

According to the commenters, regulating the use of compressed air or ''instrument air'' or other gas having little or no VOC would impose a significant burden on the industry without any added benefit.

Response: The EPA disagrees with the comment that the pneumatic controller standards must be based on VOC emissions instead of natural gas bleed rate as a surrogate for VOC emissions rate. Natural gas is being used as a surrogate for VOC given the proportional relationship between them. When a natural gas stream is emitted to the atmosphere, VOC in the gas also reaches the atmosphere since it is a component of the natural gas stream. The natural gas emissions occur without any physical separation, chemical separation or chemical reaction process of the chemical species within the natural gas; therefore, the proportion of VOC in natural gas is not altered during the course of being emitted to the atmosphere, and natural gas is an appropriate surrogate for VOC. As an example, when the natural gas emissions change, the VOC emissions change proportionately. In addition, measuring the VOC content of a pneumatic controller's bleed gas adds cost burden to companies and, to the EPA's knowledge, vendors/manufacturers do not report the VOC emissions from a pneumatic controller primarily because the VOC emissions would depend on the gas composition at the site the pneumatic controller is located.

In the preamble to the proposed rule, the EPA set forth its BSER analysis for pneumatic controllers. In the TSD, the EPA has provided cost-effectiveness calculations for the proposed pneumatic device emission limits. The commenters do not dispute the EPA's analysis. Rather, the commenters ask that the EPA establish a VOC threshold. However, the commenters have not provided information on how an appropriate threshold can be established. One commenter suggests a threshold of 10-percent VOC content by weight, but has not provided supporting information justifying this threshold. However, for the reasons stated in the response to comment in section IX.C.2 of this preamble, the EPA has decided not to cover in this final rule the pneumatic controllers in the transmission and storage segment. With respect to those controllers we are not taking final action at this time.

Comment: One commenter suggested that the EPA provide a phase-in period to allow manufacturers and companies time to designate which controllers qualify as low-bleed. This commenter further notes that bleed rates are not specified for pneumatic controllers or are inconsistently represented without distinguishing between the continuous bleed stream and the actuation stream rates within the gas consumption specifications.

Response: In the proposed rule, for pneumatic controllers[25] in the production segment other than gas processing plants, the EPA proposed a performance standard of a natural gas bleed rate of 6 scfh to reflect the use of a low-bleed controller, which we had determined to be the BSER for reducing VOC emissions from pneumatic controllers in the production segment.[26] Owners and operators would demonstrate compliance based on information in the manufacturers' specifications for the pneumatic controllers, which we had believed would provide either the bleed rate or relevant information for such determination. Upon further investigation, in light of the comments, we conclude that such information is not always included in current manufacturers' specifications. We anticipate that manufacturers who currently do not provide the relevant information for determining bleed rate would adjust to this need and begin testing their products and provide the necessary information on the products' specifications. Based on public comments and other available information, the EPA believes that an adjustment period is needed, during which owners and operators could face increased cost and, in some instances, difficulty in obtaining necessary supplies due to the limited number of currently available controllers with adequate documentation for determining bleed rate. In light of the above, we conclude that a low-bleed controller is not the BSER for pneumatic controller affected facilities in the production segment (excluding gas processing plants) during this first year. As explained in the proposed rule, we are not aware of any add-on controls that are or can be used to reduce VOC emissions from gas driven pneumatic devices. 76 FR 52760. One commenter broadly suggests that we consider flares, combustion devices and vapor recovery, but provides no supporting information. In light of the above, we conclude that there is no BSER for pneumatic controller affected sources in the production segment (excluding gas processing plants) during the ''adjustment period'' mentioned above.

In determining the length of the adjustment period, the EPA evaluated relevant comments and available information, including information from promulgation and implementation of 40 CFR part 98, subpart W of the Greenhouse Gas Reporting rule. Subpart W requires operators to conduct a complete inventory and report to EPA the number of low- and high-bleed pneumatic devices, as those terms are defined in subpart W, over a 3-year period (*i.e.*, ⅓ of their devices every year over a 3-year period) starting January 2011. We believe that efforts are well under way for manufacturers to provide necessary information to help facilities subject to subpart W determine the pneumatic controllers' bleed rates and comply with the reporting rule requirements, ⅓ of which must be reported by September 2012 and another third by September 2013 and the entire inventory by September 2014. In light of the above, we do not believe that owners and operators would face the difficulty described above beyond the first year after this NSPS becomes effective. After this first year of ''adjustment period,'' we believe owners and operators should have no problem securing controllers with relevant documentation for determining bleed rate. Therefore, beginning the second year, the BSER remains the low-bleed controllers, as proposed.

For the reasons stated above, the final rule contains no standards for pneumatic controller affected facilities in the production segment during the first year after this rule becomes effective, but, thereafter, requires that all new and modified affected facilities to meet a VOC limit of 6 scfh natural gas bleed rate to reflect the use of a low-bleed controller. The need for adequate manufacturers' specifications is not an issue for pneumatic controllers at natural gas processing plants. For pneumatic controller affected facilities at natural gas processing plants, we had proposed a zero VOC emission limit, the compliance of which can be demonstrated by the use of a non-gas-driven controller system. As noted by commenters, most natural gas processing plants already use non-gas-driven technology such as instrument air systems for safety and operational reasons. While one cannot distinguish

[25] For the reasons explained earlier in this section, we have changed the definitions of the pneumatic controller affected facility in the production segment other than gas processing plants to be a continuous bleed natural gas driven pneumatic controller with a natural gas bleed rate greater than 6 scfh. This change does not affect the proposed BSER analysis and VOC limit, which apply to high-bleed pneumatic controllers in the final rule.

[26] For reasons explained in section IX.C.2 of this preamble, unrelated to the comment at issue, the final rule does not include standards for pneumatic controllers in the transmission and storage segment.

gas-driven pneumatic controllers of different bleed-rates without information from manufacturers, a non-gas-driven controller can be easily identified by visual inspection. Therefore, no change is made since proposal to the standards for pneumatic controller affected facilities at gas processing plants.

In response to comments that units already in stock at the time of proposal cannot be used, the EPA clarifies that pneumatic controllers that were already in stock or ordered prior to August 23, 2011, are considered existing sources and, therefore, their installation is not subject to the pneumatic controllers NSPS in this final rule.

2. Controllers in the Transmission and Storage Segment

Comment: Several commenters requested the EPA reevaluate requirements for pneumatic controller/devices in the natural gas transmission segment of the industry. The commenters argue that the proposed rule's applicability is too broad and would result in an undue recordkeeping and permitting burden.

Several commenters recommend that 40 CFR part 60, subpart OOOO should limit pneumatic controller applicability to upstream processes. Some commenters suggest that, for natural gas transmission and storage, either pneumatic controllers should be completely excluded or subpart OOOO should limit applicability to equipment located at ''conventional'' facilities, *e.g.,* within the fence line at a compressor stations. One commenter recommends limiting the emission limit requirement to controllers at natural gas processing plants or locations upstream from gas processing that exceed a defined VOC threshold. The commenter suggests that this exclusion would reduce administrative costs in two ways: Mandatory recordkeeping and reporting would be removed and the documentation required to explain why excluded controllers would no longer be necessary would be removed. Another commenter suggests that the EPA state in the final rule that NSPS/NESHAP applicability alone should not trigger minor source permitting requirements.

Response: The EPA agrees that cost and other compliance burdens are important considerations in a rulemaking. In fact, the EPA believes that such consideration is particularly important here given that coverage of the transmission sector would result in a significant number of sources and owner and operators that are not subject to the current standards. Specifically, were we to finalize standards, we estimate that we would end up covering an additional 67 sources. We estimate VOC emissions from these units to be 0.1 tpy per facility or about 6 tpy nationwide for new sources, which is well below the level emitted by other affected facilities in this sector.

While our analysis suggests that this is an important set of sources to regulate, given the large number of sources, and the relatively low level of VOC emitted from these sources, we have concluded that additional evaluation of these compliance and burden issues is appropriate prior to taking final action on pneumatic controllers in the transmission and storage segment. For this reason, the requirements for pneumatic controllers in the final rule only apply to production through processing segments. Our current data indicate that the VOC content of the natural gas used for pneumatic controllers in the transmission and storage segment is low, while higher VOC content natural gas is used in the segments we are regulating. Also, for the reasons explained in the previous response to comment, no VOC threshold will be included in this regulation.

3. Cost and Emissions Calculations

Comment: One commenter asserts that the EPA's estimate of 14,000 new and replaced controllers in a given year is grossly underestimated. By the commenter's data and calculations, approximately 750,000 controllers in Texas alone may need to be replaced (unless an exemption is granted) once a well becomes subject to the new rule.

Response: The commenter incorrectly claims that the EPA's estimate of the number of pneumatic controllers installed in a given year is 14,000. In Section 5.3.2 of the TSD, the EPA explains its methodology for estimating the number of pneumatic controllers in both gas/oil production and gas transmission and storage. Table 5–3 of the TSD gives a breakdown of snap-acting versus bleed controllers and shows the total number of controllers to be 33,673. The commenter did not provide data to support its claim that there are 750,000 pneumatic controllers in Texas, or that all of them have bleed rates higher than the proposed NSPS requirements such that any future replacement would require the use of a different model (*i.e.,* low bleed or no bleed, depending on its location) of controller. In any event, the EPA has analyzed and determined that such replacement is cost-effective. One explanation for the commenter's high estimate may be a misunderstanding of the applicability of the final rule. We remind the commenter that the final rule does not apply to existing sources, unless the existing source is replaced, modified or reconstructed after August 23, 2011.

D. Major Comments Concerning Compressors

1. Compressors in the Transmission and Storage Segment

Comment: One commenter stated that the agency should exempt reciprocating and centrifugal compressors in the transmission and storage sector located after the point of custody transfer, because there is low-VOC content in natural gas from that sector. Another commenter urged the EPA to revise 40 CFR 60.5365 to exclude centrifugal compressors not associated with the Crude Oil and Natural Gas Production, Transmission, and Distribution sector. One commenter noted that some large natural gas customers (who are not in the Crude Oil and Natural Gas Production, Transmission, and Distribution sector) have natural gas centrifugal compressors that are used to increase the pressure of natural gas for use in an industrial process, or to compress natural gas used as the fuel in compressed natural gas vehicles.

One commenter argued further that even without regard to fundamental flaws stated in the five factors or methods, there still would be only trivial and inconsequential VOC reductions relative to the national VOC inventory. The commenter observed that achieving VOC reductions of 1 percent of the national anthropogenic VOC inventory would require over 21,000 regulations at 6.9 tpy, and that the EPA's estimated annual VOC reductions for compressors was similarly inconsequential. Nor, said the commenter, had the EPA adequately considered administrative burdens associated with reporting, recordkeeping and permitting. The commenter said the trivial, incremental emissions reductions that would result from the rule failed to justify the associated compliance costs and that the final rule should exclude transmission and storage sources. Another commenter expressly called on the EPA to reanalyze VOC emissions reductions and to reassess whether the rule would be cost effective. Also taking issue with supportive data, another commenter said the EPA should suspend rulemaking and expand its fact-finding to include a statistically significant sampling of affected sources. One commenter suggested that the EPA exclude centrifugal compressor facilities that compress natural gas that is less

than 10 percent, weight basis, VOC. The commenter stated that compression of gas that does not contain VOC should not be subject to standards for VOC. The commenter believes this is consistent with equipment leak rules which do not regulate components that are not in VOC service.

Response: The EPA agrees with the commenter that natural gas in the transmission and storage segment has low-VOC content. The EPA notes that cost and other compliance burdens are important considerations in a rulemaking. We estimated the VOC emissions reductions from these units located in the transmission and storage segment to be 14.1 tpy for reciprocating compressors and 6.6 tpy for centrifugal compressors, which is well below the level emitted by other affected facilities in this segment. The EPA has not fully considered compliance burden for reciprocating and centrifugal compressors in the transmission and storage segment and is, therefore, not ready to take final action with respect to these sources. While our analysis suggests that this is an important set of sources to regulate, given the number of sources, and the relatively low level of VOC emitted from these sources, we have concluded that additional evaluation of these compliance and burden issues is appropriate prior to taking final action on reciprocating and centrifugal compressors in the transmission and storage segment.

Also, no VOC threshold will be included in this regulation given the arbitrary nature of defining one using available data. We believe this revision also addresses centrifugal compressors not associated with the Crude Oil and Natural Gas Production, Transmission, and Distribution sector.

2. Dry Seals Versus Wet Seals

Comment: Several commenters address the issue of whether the EPA should permit the use of a system other than dry seal to control emissions from centrifugal compressors. Some commenters provide information on situations where dry seal systems for centrifugal compressors are not technically feasible, such as where gas composition is inadequate, in some processing plants that already have a capture system in place, and in retrofits of some existing compressors due to housing design or operational requirements. Commenters opine that the rule should allow compliance using either system, depending upon particular circumstances, and should not preclude use of a wet seal-equipped compressor with controls capable of meeting a 95-percent VOC control efficiency or routing captured seal-oil gas to a fuel gas, recycling or other processing system. According to another commenter, it would not be feasible to capture gas that escapes from a centrifugal compressor and route it back to a low-pressure fuel stream for combustion as fuel gas; although such a process would capture a minimal amount of VOC emissions, the high cost of equipment to recapture the emissions would make the method described cost-prohibitive.

Commenters generally concurred that a 95-percent reduction in emissions was achievable through installing a capture system on a wet seal compressor. In addition, commenters disagreed with the EPA's cost estimates and concluded that a wet seal capture system is cost effective.

Response: In the preamble to the proposed rule, the EPA proposed that a dry seal system is the BSER for centrifugal compressors, but solicited comments on situations where the use of a dry seal is infeasible or otherwise inappropriate and wet seal is the only option. 76 FR 52762. As noted above, several commenters provided information on situations where dry seals are not technically feasible. Therefore, the EPA has concluded that dry seal is not the BSER for all new and modified centrifugal compressors. Instead, the EPA separately evaluates the control options for wet seal compressors. The EPA has identified one control option through its review of available information, including comments and other information obtained since proposal. The option is to route captured seal-oil gas to the compressor suction, fuel gas system or flare, all of which can achieve 95-percent control efficiency.

Based on the discrepancy between commenters' and the EPA's cost data, the EPA re-evaluated its cost information for this control option. The EPA cost estimates in the proposed rule assumed the use of a new flare to combust the captured seal oil gas, and, based on commenter information, the EPA is revising this assumption since a flare or other combustion source is expected to be available in gas processing facilities. From reviewing comments received, the EPA is aware that the captured gas is not always routed to a flare but in many cases is routed back to the compressor suction or fuel system. Given this information, the EPA has re-evaluated the costs for the centrifugal compressor wet seal capture system and determined a system of this type, in which the seal oil degassing vents are routed to fuel gas, compressor suction or an existing flare would cost $22,000. The estimated cost includes an intermediate pressure degassing drum, new piping, gas demister/filter and a pressure regulator for the fuel line. With this cost, the estimated VOC control cost effectiveness is $161/ton of VOC for the processing segment. If savings are included, the cost effectiveness for VOC control is −$2,408/ton of VOC.

In light of the above, we have determined that the control option described above is the BSER for wet seal compressors. Accordingly, the final NSPS would require that wet seal compressors reduce emission by 95 percent. For dry seal compressors, the only emission control option we have identified is the use of dry seal. Accordingly, there is no requirement in the final rule for dry seal compressors, and dry seal compressors are not affected facilities under the NSPS.

3. New Source Definition

Comment: Several commenters oppose the proposal in 40 CFR 60.5365(b) and (c) that a reciprocating compressor be considered as "commenced construction" on the date of installation at a facility. Commenters argue that the EPA was "arbitrary and capricious" in proposing to apply the concept of "commenced construction" in the NSPS context to a relocated compressor, because the agency had no "reasoned explanation" for making the change and that applying the concept of "commenced construction" to a relocated compressor is contrary to the plain language of the CAA.

Response: The EPA traditionally defines the term "commence construction," as it applies to an equipment, to mean the time an owner or operator has entered into a contractual obligation to acquire the equipment. This is reflected in the definition of "commenced" in the General Provisions at 40 CFR 60.2, as well as in the relevant NSPS (see, *e.g.,* 40 CFR 60.4230(a) of subpart JJJJ). We, therefore, agree with the commenters that our proposed definition of "commence construction" in 40 CFR 60.5365(b) and 40 CFR 60.5365(c) as the time of installation is a deviation from our traditional view. Upon reviewing the comments and re-evaluating the proposed definition, we conclude that there is no discernible difference between the compressors at issue and other equipment subject to NSPS that would make such deviation necessary or appropriate in this case. We have, therefore, removed these specific definitions of "commence construction" in 40 CFR 60.5365(b) and 40 CFR 60.5365(c) in the final rule.

The NSPS also does not apply to relocated compressors. As provided in the NSPS General Provisions at 40 CFR 60.14(e)(6), relocation of an existing facility is not modification.

E. Major Comments Concerning Storage Vessels

1. Applicability Threshold Metric

Comment: Numerous commenters objected to the EPA's proposed use of liquid throughput to determine which storage vessels should be subject to the standards, asserting that the high variability in volatility of stored liquids and other parameters affecting emissions makes throughput a poor indicator of VOC emissions. The commenters indicate that, as a result, basing applicability on throughput would bring many storage vessels with low VOC emissions (some less than 1 tpy) under the standard and the required emission controls would not be cost-effective. Some commenters point out that certain storage vessels with high emissions might not be subject to the standards based on throughput.

Response: In its BSER analysis for storage vessels, the EPA estimated the VOC emissions for storage vessels with various levels of throughputs to determine the cost effectiveness of control. In that analysis, the EPA estimated that storage vessels with throughput rates of 1 barrel per day (bpd) of condensate or 20 bpd of crude oil are equivalent to VOC emissions of 6 tpy and determined that control is cost effective for these storage vessels. The EPA agrees with the comments that throughput is not a good indicator of VOC emissions and, therefore, not appropriate for determining the standards' applicability. However, the EPA has received no comment contesting the EPA's conclusion that regulating storage vessels emitting 6 tpy or more of VOC is cost effective and appropriate (the basis of our proposed throughput limit). Accordingly, in the final rule, the storage vessels NSPS applies to those emitting 6 tpy or more of VOC. This change from proposal would ensure that controls will be required only on those storage vessels where they can be applied cost effectively. This approach also allows for broader coverage across all types of storage vessels, regardless of the fluid that is stored or where the storage vessel may be located. The final rule reflects this change and has established a VOC emissions threshold of 6 tpy for storage vessels to require control. Based on our revised cost analysis, we determined that storage vessels with VOC emissions equal to or greater than 6 tpy or greater were cost effective to control at $3,400/ton of VOC. The final rule requires each facility to determine its own emission factor and calculate the estimated emissions from each storage vessel.

2. Definition of Affected Facility

Comment: Numerous commenters commented on the definition of storage vessel in 40 CFR part 60, subpart OOOO, calling for greater clarity and consistency and requesting that certain activities or equipment be included or excluded from the definition.

Response: The EPA agrees with the commenters who assert that a more specific and consistent definition of a storage vessel is needed. The revised definition more clearly focuses on identifying which units are considered storage vessels under this subpart and which units are not and describes a storage vessel using terminology similar to that used in 40 CFR part 63, subpart HH. We believe it is important to be somewhat consistent in terminology because the NSPS and NESHAP both apply to the oil and natural production segment where these tanks are primarily located. We also removed the emissions threshold from the definition and, instead, based the standard in 40 CFR 60.5395 on the VOC emission rate of the storage vessel. In response to comments requesting clarification on whether mobile units are considered storage vessels, we have set a minimum amount of time (180 consecutive days) that the storage vessel must be stationed at the same site before it is subject to 40 CFR part 60, subpart OOOO. Our reasoning for setting this minimum amount of time is discussed in the response to comment immediately below. Additionally, we have not excluded wastewater storage vessels, as the NSPS requires control for all storage vessels emitting at least 6 tpy of VOC. Further, some wastewater tanks containing significant amounts of organic compounds could exceed VOC emissions of 6 tpy. Finally, the revised definition includes specific exemptions for process vessels and pressure vessels to clarify that these units are not considered storage vessels. Since the applicability of subpart OOOO, as finalized, is not based on throughput, we believe it is not necessary to specify which types of stored materials are regulated and which are not, as suggested by commenters. If a stored material is emitting at least 6 tpy of VOC, then the storage vessel will need to reduce its VOC emissions by 95 percent.

Comment: Some commenters assert that the EPA should limit applicability to storage vessels that are stationary and should clarify the meaning of "stationary" to include or exclude certain types of storage vessels.

Additionally, the EPA received comments requesting that the stationary aspect of the "storage vessel" definition should be consistent with other rules, while acknowledging the particular scenarios unique to the oil and gas production segment. The commenter notes that the stationary aspect of a storage vessel is typically addressed by the EPA in terms of whether it is reasonably portable, although the EPA sometimes addresses portability based on the size of the vessel. The commenter states that another criterion specified by the EPA in several regulations is that "vessels permanently attached to motor vehicles" are not storage vessels, and the EPA has issued a determination that this exemption extends to storage vessels "equipped with a permanently attached wheel assembly and a truck hitch" (U.S. Environmental Protection Agency, letter from George T. Czerniak to Ken Comey, Flint Hills Resources L.P., September 2, 2004). According to the commenter, this renders most so-called frac tanks, Baker tanks, International Organization for Standardization tanks, etc., exempt from the storage vessel provisions when this form of definition is used. However, the commenter recognizes that such storage vessels sometimes become effectively "stationary" in oil and gas production operations and suggests that storage vessels should be deemed stationary if they remain at a given site for more than 180 consecutive days, consistent with the period of time allowed under 40 CFR 60.14(g) to achieve compliance after a modification. The commenter notes that this 180-day period is reasonable given that the definition of non-road engines in 40 CFR 89.2 allows a period of 12 consecutive months.

The commenter also points out that cost effectiveness of the proposed control measures has been evaluated under the assumption that storage vessels remain in place for the useful life of the control equipment, and, thus, the control costs are amortized over a period of years. Since the cost per ton of emission reductions would be much higher if the controls were applied to a storage vessel that is only on site temporarily, the commenter believes that a cost-effectiveness analysis for permanent storage vessels would not be valid for temporary storage vessels, and, thus, the control requirements for permanent storage vessels are not justified for temporary storage vessels. The commenter provides recommended language for the definition of "storage vessel" that addresses this and other

concerns. Another commenter similarly states that costly control requirements are not appropriate for temporary storage vessels (on site less than 180 days).

Response: Based on the commenter's suggestion, the EPA has revised the definition of storage vessel to clarify that a storage vessel is subject to 40 CFR part 60, subpart OOOO if it remains on a given site for more than 180 consecutive days.

In general, we agree with the commenter's discussion about the EPA's past practices related to storage vessels. In particular, we agree that the inherent differences between "mobile" or temporary storage vessels in this source category and other categories indicate that they should be regulated differently. As mentioned in the previous response, there are many storage vessels in this source category that travel from site to site, so we did not feel it was appropriate to exclude all of these mobile storage vessels from control requirements. Many temporary storage vessels in this source category are typically bringing in material such as fracking fluid to well sites and can stay at a well site for up to several months in order to receive flowback. These storage vessels are considered to be an essential part of the drilling and production operation, more akin to how permanent storage vessels are utilized in the refining and organic chemical manufacturing sectors, rather than to conventional tank trucks that are typically excluded in other EPA rules. Therefore, we believe that 180 days is an appropriate period of time to establish a temporary tank as being subject to 40 CFR part 60, subpart OOOO, and, therefore, potentially required to install controls.

3. References to MACT Standards

Comment: The EPA received comment asserting that the outcome of its best demonstrated technology (BDT) analysis for proposed 40 CFR part 60, subpart OOOO was calculated to achieve the same level of control as 40 CFR part 63, subpart HH—undermining the BDT determination and effectively (and unlawfully) extending subpart HH major source MACT requirements to area source storage vessels.

As a result, the commenter asserts that the EPA's analysis precludes other potentially relevant regulatory alternatives—such as marginally less effective controls that might be applied to a broader range of storage vessels. The commenter states that the EPA's failure to consider other control techniques and other levels of control efficiency that might be achieved by its preferred techniques is arbitrary and capricious.

Response: The commenter incorrectly asserts that the EPA's NSPS for storage vessels was designed to achieve the same level of control as MACT in 40 CFR part 63, subpart HH. In *Portland Cement Assoc.* v. *EPA,* 665 F.3d 177 (D.C. Cir. 2011), the United States Court of Appeals for the District of Columbia Circuit rejected an argument that the EPA adopted NESHAP PM standards for NSPS, noting that the EPA arrived at the same limit for both NESHAP and NSPS using two different mechanisms. Similarly, in this case, although both the NESHAP and the NSPS require 95-percent control, the EPA established the two standards based on separate mechanisms. The EPA established the MACT standard in 1998 pursuant to section 112(d)(2) and (3) of the CAA. In contrast, the EPA established the NSPS based on BSER analysis under CAA section 111. The BSER analysis for storage vessels consists of the same steps as those for other affected sources evaluated in the proposed NSPS. Specifically, the EPA evaluated available information to identify VOC control options. The EPA then assessed various aspects of the control options, including their VOC reduction potentials, their cost effectiveness and secondary air impacts. The commenter did not claim that any part of the EPA's BSER analysis above was inaccurate or inappropriate. For the reasons stated above, the commenter's assertion is without support.

The commenter also claims that the EPA only analyzed two controls and, therefore, failed to consider other "potentially relevant regulatory alternatives." However, the commenter did not identify any other control option for the EPA's consideration. The commenter simply suggests that the EPA should consider some less effective controls, which the commenter claims would have led to greater coverage. Without more information, it is unclear whether a less effective control than that we have identified would, in fact, qualify as BSER for controlling VOC emissions from storage vessels or would have resulted in coverage of additional storage vessels.

Comment: Two commenters state that the cost of the performance tests, monitoring, recordkeeping, etc., that are required through cross-references to 40 CFR part 63, subpart HH were not adequately considered by the EPA in the cost-effectiveness determination for 40 CFR part 60, subpart OOOO, which applies to dispersed locations that do not have electricity or automation, and have limited remote transmitting unit space.

Response: The EPA does not take into account monitoring, recordkeeping and reporting costs in determining cost effectiveness of controls and in evaluating BSER. Based on this and other comments detailed in the response to comments for this final rulemaking, the EPA removed from 40 CFR part 60, subpart OOOO the citations to the requirements for performance tests, monitoring, recordkeeping, etc., in 40 CFR part 63, subpart HH and incorporated these subpart HH requirements into subpart OOOO. During the incorporation process, we made minor revisions to the subpart HH requirements, as appropriate for subpart OOOO. For example, we removed references to glycol dehydrators and paragraphs listed as "reserved."

4. Availability of Control Equipment

Comment: Some commenters believe that there will be a shortage of control equipment available to meet the proposed storage vessel requirements, and recommend revisions to the compliance deadline for storage vessels based on a variety of considerations, including the availability of control devices, lead time needed for manufacturer testing of their combustors to be compliant with the NSPS and time needed to install the compliant devices.

Response: We agree that it will likely take some time beyond the promulgation date of the NSPS for combustor manufacturers to have control devices constructed, tested, documented and available for operators to install in efforts to comply with the storage vessel requirements of the NSPS. Under the final rule, operators are not required to conduct individual performance tests on combustors installed in the field if the combustor manufacturer tests and documents for the owner or operator that the model achieves a control efficiency of 95.0 percent. The time required for testing and documentation is often longer than for a single model when manufacturers provide multiple models for varying applications based on capacity. We believe this testing and documentation program would require an "adjustment period" for manufacturers to be ready to supply the operators with the correct equipment they need.

We considered whether it would be feasible for on-site testing to mitigate the shortage of manufacturer tested combustors. Although owners and operators can test their individual combustors in the field to determine combustor efficiency, such emissions testing is expensive and can only be

performed if testing consultants are available to conduct the testing. We believe that immediately after the effective date of the NSPS there will be a shortage of available testing consultants concurrent with the shortage of pre-tested combustor models. As a result, we conclude that on-site testing would not sufficiently mitigate the difficulty of owners and operators complying with the NSPS.

We evaluated whether controls other than combustors would be available during this adjustment period. Although vapor recovery units (VRU) can provide 95.0-percent control for storage vessels and are one means of meeting the storage vessel standards in the NSPS, VRU cannot be used in every situation. For example, storage vessels located remotely where there is no available electrical service may not be able to be controlled using VRU. In addition, storage vessels with low concentration emission streams or fluctuating emissions may not be amenable to control by VRU. Further, VRU installations would also require on-site testing, and owners and operators would be hampered by the same consultant shortage situation described above for combustors.

In light of the above, we conclude that there is no BSER for storage vessel affected sources during the first year after promulgation, which we believe is appropriate for the adjustment period mentioned above. At the end of this adjustment period, we believe owners and operators should have no problem securing control devices that are manufacturer-tested and have appropriate documentation for determining control efficiency. Accordingly, the final rule provides for a 1-year phase-in beginning October 15, 2012 before the 95.0-percent control requirement is effective.

With regard to providing time for operators to establish the need for controls and install them where called for, the EPA agrees that some lag time may be needed after initial start-up for the owner or operator to determine the long-term production level of a well and to procure the appropriate control equipment. The EPA evaluated the approach taken in the Wyoming rules for new sources, which allows from 30 to 90 days for a source to achieve compliance, depending on the area of the state. Wyoming allows only 30 days in ozone nonattainment areas, 60 days for concentrated development areas or 90 days elsewhere in the state. The EPA believes that 60 days is a reasonable period for controlling new storage vessels at wells sites with no wells already in production.

However, for replacement storage vessels or additional storage vessels at well sites with one or more wells already in production, we believe the operator already should have information on liquid composition and throughput. This information would allow estimation of VOC emissions to determine applicability of control requirements and for acquisition and installation of a control device concurrent with the replacement or additional storage vessel being installed. In the final rule, for storage vessels constructed, modified or reconstructed at well sites with no well already in production, we have provided for a 30-day period for throughput to stabilize and for the operator to estimate VOC emissions to determine whether a control device will be required. If VOC emissions are estimated to be at least 6 tpy, the operator is provided an additional 30 days for the control device to become operational. We believe that the Wyoming experience illustrates that this will be sufficient time to size and obtain suitable controls.

F. Major Comments Concerning Notification, Recordkeeping and Reporting Requirements

1. 30-Day Notification and Annual Reports

Comment: Multiple commenters state that the 30-day advance notification of well completions under 40 CFR 60.5420(a) should be removed from the final rule. Commenters assert that this and notification requirements in 40 CFR 60.7(a) are unduly burdensome and costly, not adequately explained, not related to verifying compliance with the proposed rule and could conflict with the need to protect proprietary business information.

Multiple commenters also note that industry's estimate of annual completions is several times higher than the EPA's estimate of 20,000 completions following fracturing and completions following refracturing annually. The commenters believe that these requirements will likely overwhelm both regulated entities and state regulators alike. Commenters offer suggestions, including requiring annual certifications or maintaining records available for inspection, reducing the proposed advance notification requirement to 5–10 days and considering notification programs such as those in Texas and Wyoming. Different commenters support or oppose requiring a 30-day advance notice with follow-up notification of 1–2 days before an impending completion.

Several commenters suggest that the EPA should coordinate with state and local agencies to eliminate duplicative recordkeeping and reporting requirements, and that records of interest other than those submitted to the respective Oil and Gas Commissions should only be required to be retained and available upon inspection, similar to other permit requirements.

Several commenters do not agree that an annual report under 40 CFR 60.7(a)(1), 40 CFR 60.7(a)(3) and 40 CFR 60.7(a)(4) adds any value for verifying compliance and the EPA should remove this requirement from the final rule. The commenters add that the best method for compliance is for an owner or operator to maintain necessary records and to have the records available for review during an on-site inspection. One commenter suggests the annual report should include for each type of affected facility (1) the total number of affected facilities at the site; (2) the number of facilities that became affected facilities during the reporting period; (3) the number of exempted facilities; and (4) the number of affected facilities with a non-compliance situation during the reporting period. One commenter suggests that it would be easier for facilities to submit an annual report on a set date each year, and multiple affected facilities could be included in a single report. Two commenters propose that all notifications for each year be delivered in a single annual report corresponding to the reporting period in which the affected facilities become subject to the rule. One commenter suggests that operators should be required to keep records at the nearest manned office, but reports should only be required if they are requested by the EPA.

The commenters recommend, where feasible, streamlining the final notification and reporting requirements to eliminate unduly burdensome notification and reporting requirements.

Response: The EPA agrees that certain notification, recordkeeping and reporting requirements in the General Provisions are unduly burdensome for the new affected facilities in this NSPS. For that reason, well completions, pneumatic controllers and storage vessels will be exempt from the notifications required by 40 CFR 60.7(a)(1), (3) and (4). We agree that notifications of well completions should be as streamlined as possible to remove excess burden from both the owners and operators and regulatory agencies, as well. As a result, we have removed the 30-day advance notification requirement and instead are requiring an advance notice via email to the EPA or delegated

authority no later than 2 days prior to completion.

To avoid duplicative and potentially conflicting notification requirements and to relieve notification burden from owners and operators, we have added a provision in the final rule that, if an owner or operator has met the state requirements for advance notification of well completions, then the owner and operator are considered to have met the advance notification requirement for gas well completions under the NSPS.

We also believe that the operator should be provided flexibility to use new technology to document compliance that would result in less paperwork burden on the part of the operators themselves and on regulators. To lessen the reporting burden, the final recordkeeping and reporting requirements for well completions also provide for a streamlining option that owners and operators may choose in lieu of the standard annual reporting requirements. The standard annual report must include copies of all well completion records for each gas well affected facility for which a completion operation was performed during the reporting period. The alternative, streamlined annual report for gas well affected facilities requires submission of a list, with identifying information of all affected gas wells completed, electronic or hard copy photographs documenting REC in progress for each well for which REC was required and the self-certification required in the standard annual report. The operator retains a digital image of each REC in progress. The image must include a digital date stamp and geographic coordinates stamp to help link the photograph with the specific well completion operation. Operators are not required to take advantage of the optional recordkeeping and reporting approach, as some may choose to follow the standard reporting requirements. Under either approach, the report must include a record of all deviations during the reporting period in cases where well completion operations with hydraulic fracturing were not performed in compliance with the requirements for each gas well affected facility.

Comment: One commenter requested that the EPA add a self-certification requirement to the annual report similar to that used in the title V program. The commenter recommended that the final rule require the annual report to include a statement signed by a senior official of the facility attesting to the truth, accuracy and completeness of the report.

The commenter also requested that the EPA require that the annual reports be submitted electronically to facilitate making the reports publicly available. The commenter suggested using social media outlets, smart phone applications and other electronic means to make the annual reports readily available.

Response: The EPA agrees that self-certification is an important mechanism for assuring the public that the information submitted by each facility is accurate. In addition, the title V program has successfully employed self-certification since its inception. Therefore, we are requiring self-certification, based on requirements in the title V program, in the final rule.

While we agree that having annual reports readily available to the public is a desirable goal, we did not identify any reporting programs or electronic databases that may be used for this purpose without significant modification. Therefore, we are not requiring annual reports to be submitted electronically, but we will continue to evaluate this option in the future.

2. Duplicative Recordkeeping and Reporting Requirements

Comment: Multiple commenters state that the notification, recordkeeping, monitoring and annual reporting requirements in the proposed NSPS are duplicative and extremely burdensome for operators and for state regulators with limited resources. The commenters make both general and specific recommendations to revise the reporting requirements in the final rule to eliminate duplication and reduce burden or better inform the public and regulatory agencies about deviations. Some commenters would eliminate all or some reports, while others argue that reporting is an essential compliance and enforcement mechanism and that additional information should be provided. Some commenters feel that an owner or operator should maintain necessary records and have them available for review.

Commenters want the compliance assurance requirements to be appropriate for the oil and gas industry and commensurate to the environmental benefit that will be generated. For example, some commenters feel that the EPA should exempt small sources regulated under this rule from the notification and reporting requirements.

Response: We have considered these and other related comments presented in the response to comments regarding the proposed reporting requirements. The EPA agrees that certain notification, recordkeeping and reporting requirements are unduly burdensome and believes it is important to minimize the burden of reporting requirements. However, as noted in several comments, states and other enforcement entities are confronting limited resources and visiting sites is not always practical and is particularly challenging in this industry. For that reason, the EPA believes notifications and reporting requirements are vital to ensure compliance with our regulations. Therefore, the EPA has evaluated the proposed notification, recordkeeping and reporting requirements in an effort to streamline the requirements to reduce burden on both industry and enforcement at the same time, assuring compliance with the NSPS. In the final rule, the EPA has removed or otherwise revised proposed reporting requirements that the EPA believes to be duplicative or unnecessary, including, but not limited to, those raised in the comments. These changes will streamline the reporting process and reduce the reporting burden on sources, including small sources. For example, as previously discussed, well completions and continuous bleed natural gas controllers are exempt from the notifications required by 40 CFR 60.7(a)(1), 40 CFR 60.7(a)(3) and 40 CFR 60.7(a)(4). In addition, the EPA has revised the rule language such that only continuous bleed natural gas controllers installed, modified or replaced during the reporting period are reported in the annual report. In addition, the EPA has revised the 30-day individual notification requirement for well completions, as discussed above.

3. Electronic Reporting of Emissions Data

Comment: Commenters suggest a variety of ways in which electronic reporting could be structured and implemented, with attention to coordination with various CAA requirements and programs to avoid duplicative and potentially burdensome requirements. Several commenters support electronic reporting of emissions data from all sources to be stored on existing EPA databases, such as the Electronic Greenhouse Gas Reporting Tool (e-GGRT) or added to the Toxics Release Inventory, and available to the public. These commenters believe that communities must have access to air quality information in order to protect public health. One commenter objects to the use of e-GGRT as a reporting mechanism in place of a state's own tracking system, where the state has enforcement responsibility for the emissions date and tracking of sources subject to the proposed rule. The commenters also suggested a variety of ways in which electronic

reporting could be structured and implemented.

Several commenters oppose the implementation of electronic reporting at this time and are concerned that an ERT will result in numerous complications and undue additional burden. The commenters point out that the EPA's experience with e-GGRT indicates that considerable time and resources are needed to develop and implement efficient systems and to ensure that electronic reporting enhances efficiency rather than incurring additional burden on affected sources. The commenters state that a potential disadvantage associated with an ERT is that new and/or alternative test methods would not be in the system. In addition, the commenters believe that an ERT could be complicated and burdensome for smaller companies that lack environmental personnel or experience with electronic reporting under other rules. The commenters suggest that if the EPA delegates authority to states to implement and enforce the standards, some states may be unable or unwilling to accept electronic reports. The commenters urge the EPA to consider other more simplified options to report only the needed information.

Response: While the EPA supports and encourages electronic reporting, after further consideration of all the comments, we do not believe the e-GGRT is the appropriate mechanism for electronic reporting under this rule, as recommended by some commenters. The e-GGRT is not designed to accept all of the types of information required to be reported under the final rule, and significant modification of the system would be required to make it operational for this rule.

However, the final rule does include reporting of performance test data via the ERT. The EPA must have performance test data to conduct effective reviews of CAA sections 112 and 129 standards, as well as for many other purposes, including compliance determinations, emission factor development and annual emission rate determinations. In conducting these required reviews, the EPA has found it ineffective and time consuming, not only for us, but also for regulatory agencies and source owners and operators, to locate, collect and submit performance test data because of varied locations for data storage and varied data storage methods. In recent years, though, stack testing firms have typically collected performance test data in electronic format, making it possible to move to an electronic data submittal system that would increase the ease and efficiency of data submittal and improve data accessibility.

In the final rule, as a step to increase the ease and efficiency of data submittal and improve data accessibility, the EPA is requiring the electronic submittal of select performance test data. Data entry will be through an electronic emissions test report structure called the ERT. The ERT will generate an electronic report which will be submitted using the CEDRI. The submitted report is submitted through the EPA's CDX network for storage in the WebFIRE database making submittal of data very straightforward and easy. Webfire is the EPA's online emissions factor repository, retrieval and development tool. The WebFIRE database is open to the public and contains the EPA's recommended emissions factors for criteria and HAP for industrial and non-industrial processes. Emissions data collected from the oil and natural gas sector, as well as many other sectors, will be used to update our emissions factors. The data will also be used by the EPA's rule writers to make better informed decisions and learn more detailed information about emissions from sources. The electronic reporting requirement in this rule (and other NSPS/NESHAP rules) is only for test methods that are supported by the ERT.

One major advantage of submitting performance test data through the ERT is a standardized method to compile and store much of the documentation required to be reported by this rule. Another advantage is that the ERT clearly states what testing information would be required. Another important benefit of submitting these data to the EPA at the time the source test is conducted is that it should substantially reduce the effort involved in data collection activities in the future.

State, local and tribal agencies can also benefit from a more streamlined and accurate review of electronic data submitted to them. The ERT allows for an electronic review process rather than a manual data assessment making review and evaluation of the data and calculations easier and more efficient. Finally, another benefit of submitting data to WebFIRE electronically is that these data will greatly improve the overall quality of the existing and new emission factors by supplementing the pool of emissions test data for establishing emissions factors and by ensuring that the factors are more representative of current industry operational procedures. A common complaint heard from industry and regulators is that emission factors are outdated or not representative of a particular source category. With timely receipt and incorporation of data from most performance tests, the EPA will be able to ensure that emission factors, when updated, represent the most current range of operational practices.

X. Summary of Significant NESHAP Comments and Responses

For purposes of this document, the text within the comment summaries was provided by the commenter(s) and represents their opinion(s), regardless of whether the summary specifically indicates that the statement is from a commenter(s) (*e.g.,* ''The commenter states'' or ''The commenters assert''). The comment summaries do not represent the EPA's opinion unless the response to the comment specifically agrees with all or a portion of the comment.

A. Major Comments Concerning Previously Unregulated Sources

Comment: One commenter asserts that, although the EPA's original MACT analysis covered all storage vessels, it issued a MACT standard at that time that applied to storage vessels with the PFE only. The commenter states that, while they support the EPA's effort to correct this omission, the initial analysis for the tanks that the agency did regulate in 1999 was seriously flawed, and the proposed rule provides no justification for continuing to rely on a 13-year old analysis to propose a MACT standard for an entirely new universe of storage vessel sources. Thus, according to the commenter, the EPA's failure to properly calculate the MACT floor in setting the MACT standard for storage vessels violates CAA section 112(d)(2) and (3).

The commenter states that, because this method has been found to be unlawful and substantially more data are available at this time, the EPA must now recalculate the MACT floor and MACT limits for tanks with the PFE. *Cement Kiln Recycling Coalition, et. al.* v. *U.S. EPA,* 255 F.3d 855, 863–64 (D.C. Cir. 2001). The commenter asserts that, in addition and partly as a consequence of its unlawful reliance on the prior standards, the EPA also has failed to fulfill the beyond-the-floor requirement of CAA section 112(d)(2). The commenter opines that, absent an up-to-date analysis based on current emission controls, an appropriate beyond-the-floor determination cannot be made.

Two commenters do not believe that the dataset used is representative of currently operating small glycol dehydrators. One commenter believes that the EPA has not satisfied section 112(d)(2) and (3) of the CAA and that the EPA needs to calculate the MACT

limit based on the best-performing sources that currently exist.

One commenter recommends that the EPA base its MACT floor analyses on emissions data from a representative population of small dehydrators that characterize the population of affected sources within the category or subcategory. The commenter reports that more current data sources may be available, such as dehydrator emissions data reported to state agencies in annual emission reports or in permit applications.

One commenter opines that the EPA's proposal misses the opportunity and fails to fulfill the agency's responsibility to properly calculate the MACT for all sources in this sector based on current, reliable and representative emission test data. The commenter believes that, by relying on an incomplete and outdated dataset to set MACT floors and limits, the EPA has ignored data demonstrating trends in practices, processes and technologies and the resulting improved performance that CAA section 112(d) mandates. The commenter asserts that the EPA ignores the potential HAP emissions that the control devices themselves emit by failing to collect such emissions data from facilities that have installed control devices. The commenter argues that the EPA must collect the appropriate emission test data needed in order to recalculate and set a proper MACT for glycol dehydrators, storage vessels and equipment leaks.

One commenter states that section 112 of the CAA requires the EPA to set a NESHAP for each category or subcategory of "major sources" of HAP emissions. 42 U.S.C. 7412(d)(1). The commenter asserts that the EPA must set CAA section 112(d) emission standards based on "maximum achievable control technology" or "MACT." The commenter states that the EPA largely bases its MACT proposal for small glycol dehydrators on emissions data collected from the industry during the development of the original MACT standards. 76 FR 52768. The commenter contends that the data were collected prior to 1997 and did not adequately represent the emissions profile at that time, and do not reflect the significant changes in the industry and other technological developments that have occurred during the past 13 years. According to the commenter, the EPA has not provided a reasoned explanation of how those data could be representative of currently operating glycol dehydrators and associated emission reductions, and how proposals based on those data can currently meet the MACT requirements for new and existing sources. The commenter states that the dehydrator technology performance in 1997 was not accurately reflected in the legacy EPA dataset and has advanced significantly in the past 13 years. Consequently, according to the commenter, the EPA has not provided a reasoned explanation of how those data could be representative of currently operating glycol dehydrators and associated emission reductions, and how proposals based on those data can currently meet the MACT requirements for new and existing sources. The commenter believes this is critical because the 2005 NEI data reveal that improvements in the environmental performance of the category have progressed such that there are far more units in service with lower emissions than reflected in the 1997 data.

One commenter states that the EPA did not collect recent data regarding emissions of HAP, including BTEX, from small glycol dehydrators in either source sector in support of this rulemaking. Instead, according to the commenter, the EPA appears to have relied on data collected in the prior MACT rulemaking, going back to 1998 or prior. The commenter believes that the EPA's analysis is flawed and questionable because it simply relies on the best-performing sources that existed a decade ago and fails to identify the best controlled sources today. The commenter contends that it is unlikely that these MACT standards reflect either the current best controlled similar source emissions or the average of the top 12 percent of the currently best controlled sources. The commenter states that, while the EPA appropriately proposes to set a MACT limit for these sources for the first time, the EPA's use of out-dated data fails to demonstrate that its proposed limit is stringent enough in light of significant developments in emission control technologies and practices that have occurred since 1998.

Response: One commenter argues that EPA has not satisfied sections 112(d)(2) and (3) of the CAA, because the MACT standards set in the 1999 rule have not been re-calculated using current data. To the extent the commenter is arguing that CAA section 112(d)(6) requires that the EPA recalculate the MACT standards set in 1999, based on current emissions test data, the commenter is incorrect. In *NRDC* v. *EPA,* 529 F.3d 1077, 1084 (D.C. Cir. 2008), the District of Columbia Circuit held that it "[did] not think the words 'review, and revise as necessary' can be construed reasonably as imposing any such obligation" to re-calculate the MACT floors. *NRDC* v. *EPA,* 529 F.3d 1077, 1084 (D.C. Cir. 2008).

Moreover, in this action, we did not re-open the MACT standards in 40 CFR part 63, subpart HH for large glycol dehydrators, storage vessels with the PFE and equipment leaks for or in 40 CFR part 63, subpart HHH for large glycol dehydrators. As such, the commenter's request that we re-calculate those standards based on current emissions data is outside the scope of this rulemaking. We did, however, conduct a CAA section 112(d)(6) technology review for subpart HH and determined that there have been no developments in practices, processes or control technologies for large glycol dehydrators, storage vessels with the PFE and equipment leaks and that there have been developments for equipment leaks. See *Technology Review for the Final Amendments to Standards for the Oil and Natural Gas Production and Natural Gas Transmission and Storage Source Categories* and responses on section 112(d)(6) comments below. We also conducted a CAA section 112(d)(6) technology review for subpart HHH and determined that there have been no developments in practices, processes or control technologies for large glycol dehydrators. *Id.*

The remaining comments focus on the data the agency used to set the proposed MACT standards for small glycol dehydrators, which were left unregulated in the 1999 rule. The commenters claim that the data the EPA used to set the BTEX MACT standards for the small glycol dehydrators subcategory are outdated and that the EPA must collect new data. However, CAA section 112(d)(3) specifically provides that the Agency is to determine the average emission limit achieved by the best performing 12 percent of existing sources "(for which the Administrator has emissions information)." Thus, the EPA is not required to collect information if it determines that the information it has is sufficient for it to calculate the MACT standards consistent with the requirements of CAA section 112. Although the available emissions information is over a decade old, the available controls for reducing BTEX emissions from small glycol dehydrators and their control efficiencies have remained the same during this period, and the commenters have not provided any data to the contrary.[27] We,

[27] Memorandum from Brown, Heather, EC/R Inc., to Moore, Bruce, U.S. EPA, titled *Technology Review for the Final Amendments to Standards for the Oil and Natural Gas Production and Natural*

Continued

therefore, believe the data we have are still representative of the performance of the small dehydrators.

Moreover, we believe that the collection and analysis of additional data would take time and further delay control of these sources, which we do not think is warranted where, as here, we believe the data on BTEX emissions for the subcategory of small glycol dehydrators are still representative of these sources' performance today and the commenter did not provide any data that indicates otherwise.

Finally, for small glycol dehydrators, we considered using more current available data, like the 2005 NEI, however, the NEI dataset lacks specific information that we believe is relevant to identifying the best performing units. Specifically, the NEI data lacks information on inlet HAP content and gas throughput, both of which affect a glycol dehydrator's HAP emissions. Inlet HAP content varies from well site to well site. A well-controlled glycol dehydrator at a well site with high inlet HAP content may have higher HAP emissions than a totally uncontrolled glycol dehydrator at a well site with a low inlet HAP content. Natural gas throughput also affects a glycol dehydrator's overall emissions (*i.e.,* low throughput units will tend to have lower overall emissions, and vice versa). For the reasons stated above, in addition to emissions, we need to consider the inlet HAP content and gas throughput of the small glycol dehydrators in order to properly identify the best performing sources and establish the MACT standard for this subcategory. However, information on natural gas throughput and inlet HAP content is not included in the NEI or any other readily available data source. Therefore, we used the 1997 data which included such information for the small dehydrators.

Comment: One commenter supports the EPA's regulation of previously unregulated sources in the oil and natural gas sector and the commenter asserts that CAA sections 112(c) and 112(k) (Urban Air Toxics Strategy) support their position regarding the regulation of previously unregulated sources. The commenter asserts that historical regulation of emission sources within the sector leaves a large number of dehydrators, storage vessels and equipment at gas processing plants unregulated. Additionally, the commenter states that historical regulation has also not limited emissions from a number of other emission sources (*i.e.,* wells, pneumatic devices, compressor seals, valves, or flanges or other production equipment located at oil and gas production facilities or natural gas storage transmission facilities).

One commenter supports the EPA's recognition of the need to control emissions from previously uncontrolled emission points and commends the EPA on addressing small glycol dehydration units and storage vessels without the PFE. The commenters request that the EPA address all of the uncontrolled HAP emission points of which it is aware.

Response: This rule establishes MACT standards for major sources of small glycol dehydrators that were left unregulated in the 1999 MACT rule. As explained further below, in several recent rulemakings, we have chosen to fix certain underlying defects in existing MACT standards under CAA sections 112(d)(2) and (3), which are the provisions that directly govern the initial promulgation of MACT standards (see National Emission Standards for Hazardous Air Pollutants From Petroleum Refineries, October 28, 2009, 74 FR 55670; and National Emission Standards for Hazardous Air Pollutants: Group I Polymers and Resins; Marine Tank Vessel Loading Operations; Pharmaceuticals Production; and the Printing and Publishing Industry, April 21, 2011, 76 FR 22566). We believe that this approach is reasonable because using those provisions ensures that the process and considerations are those associated with initially establishing a MACT standard, and it is reasonable to make corrections following the process that would have been followed if we had not made an error at the time of the original promulgation. We appreciate the commenter's support for regulating small glycol dehydrators.

Although the agency had proposed MACT standards under CAA sections 112(d)(2) and (3) for the subcategory of storage vessels without the PFE, we are not finalizing those standards here. Based on our review of the comments, we believe that we need additional data in order to set an emission standard for these vessels. We intend to collect the appropriate data and propose a MACT emission standard under CAA sections 112(d)(2) and (3) of the CAA.

The commenter identifies certain emission sources, other than small glycol dehydrators and storage vessels without the PFE (*e.g.,* wells), that it alleges are uncontrolled. CAA section 112(n)(4)(A) prohibits aggregation of emissions from any oil and gas exploration or production wells (with their associated equipment) in determining major source status or for any purpose under CAA section 112. In light of this prohibition on aggregation, and the fact that the sources identified by the commenter likely would not, if viewed alone, qualify as a major source, it is not clear whether emissions from the sources identified by the commenter can be addressed by a major source NESHAP.[28]

The commenter also references CAA section 112(k) (and the Urban Air Toxic Strategy). CAA section 112(k) is designed to address area source emissions in urban areas. This rule involves a review of 40 CFR part 63, subparts HH and HHH, both of which address major sources, not area sources. Further, oil and gas production facilities are typically not sited in urban areas.

To the extent that the commenter is requesting EPA to list area source oil and gas production wells, such a request is outside the scope of this action. See CAA section 112(n)(4)(B) (specifying certain requirements for listing "oil and gas production wells (with its associated equipment)" as an area source category).

B. Major Comments Concerning the Risk Review

Comment: One commenter states that the EPA's analysis for 40 CFR part 63, subpart HH revealed two facilities (Hawkins Gas Plant, Hawkins, Texas, and Kathleen Tharp 2, Huffman, Texas) with a cancer MIR greater than 100-in-1 million based on MACT allowable emissions. The commenter notes that since the EPA determined that these facilities had a cancer MIR greater than 100-in-1 million based on MACT allowable emissions, the EPA determined that the risks are unacceptable for the Oil and Natural Gas Production MACT source category and additional regulation was needed. However, the commenter believes these results are entirely incorrect due to fundamental errors in the EPA's calculations of MACT allowable risk for these two facilities. In addition, even if the analysis had been correct, the commenter states there are significant issues associated with the data for both of these facilities, which the commenter discusses in detail, that the commenter believes are sufficient to invalidate the results and the EPA's conclusion that risks from the Oil and Natural Gas Production source category are unacceptable.

Response: We have reviewed our risk results for the Oil and Natural Gas Production source category and agree

Gas Transmission and Storage Source Categories. Dated April 17, 2012.

[28] Even if the commenter were to identify an unregulated emission point under the NESHAP, it can always petition the agency to revise the 1999 MACT standards.

with the commenter that a number of errors were made in our analysis, including those noted by the commenter. As explained in VII.A.2 of this preamble, we have revised the risk assessment for this major source category to correct certain mistakes made in the analysis supporting the proposed rule.

Based on our revised risk assessment, in which we evaluated the risks that remain after promulgation of the original MACT standards, as well as the MACT standards for small glycol dehydrators established in this final rule, we have determined the risks for the Oil and Natural Gas Production major source category are acceptable and that the MACT standards (including those promulgated here for small glycol dehydrators) provide an ample margin of safety. Further, we are retaining the 0.9 Mg/yr benzene compliance alternative, which we had proposed to remove based on our incorrect conclusion that this alternative was driving the risk for this major source category.

Comment: One commenter states that the EPA bases the decision to eliminate the 0.9 Mg/yr benzene emission limitation for 40 CFR part 63, subpart HHH on two basic factors: (1) It would reduce the cancer MIR from 90-in-1 million to 20-in-1 million, and (2) the cost effectiveness to comply with this option is reasonable. The commenter states that both of these conclusions are erroneous.

First, the commenter states that removal of 0.9 Mg/yr benzene alternative does not reduce risk. The commenter states that the EPA's own technical analysis indicates that removal of the 0.9 Mg/yr benzene alternative would have no effect on the MIR.

Secondly, the commenter states that the EPA's cost analysis is severely flawed. The commenter also states that the EPA noted at proposal, that the cost-effectiveness associated with removing the 0.9 Mg/yr benzene compliance alternative for natural gas transmission and storage facilities was reasonable. However, the commenter explained that the cost estimates used by the EPA in the ample margin of safety determination are inadequate. According to the commenter, the EPA did not conduct any analysis using actual data. Rather, the commenter notes that the EPA used costs estimated for small dehydrators and made general assumptions to estimate an upper-end cost effectiveness for removing the 0.9 Mg/yr benzene alternative limit for large dehydrators at natural gas transmission and storage facilities. The commenter believes that, in general, the emission reductions for dehydrators forced to switch from the 0.9 Mg/yr benzene alternative to 95-percent control would be considerably less than those achieved by small dehydrators. The commenter further notes that the cost-effectiveness calculated for small dehydrators is based on a 95-percent reduction from an uncontrolled baseline level. According to the commenter, if a large dehydrator has installed controls to meet the 0.9 Mg/yr alternative benzene limitation, the cost effectiveness must be based on the incremental reduction between the existing controls and 95 percent. The commenter states that the EPA has provided no evidence that these incremental reductions would be greater than or equal to the 95-percent reductions that would be achieved for smaller dehydrators. In conclusion, the commenter states that the rationale used by the EPA in the preamble to support the removal of the 0.9 Mg/yr compliance alternative for dehydrators at natural gas transmission and storage facilities under section 112(f)(2) of the CAA is not supported by any of the background technical documentation and analyses. The commenter believes that the EPA has no basis under any other CAA authority for this action.

Response: In response to comments, we re-examined our risk assessment for the Natural Gas Transmission and Storage source category and discovered a number of errors, which we have discussed in more detail in section VII.B.2 of this preamble. As explained in that section, we have revised the risk assessment for this major source category to correct the mistakes. Based on our revised risk assessment, in which we evaluated the risks that remain after promulgation of the original MACT standards, as well as the MACT standards for small glycol dehydrators in this final rule, we have determined that the risks for the Oil and Gas Transmission and Storage major source category are acceptable and that the MACT standards (including those promulgated here) provide an ample margin of safety. Further, we are retaining the 0.9 Mg/yr benzene compliance alternative, which we had proposed to remove based on our incorrect conclusion that it was driving the risk for this major source category. We agree with the commenter that removal of the 0.9 Mg/yr benzene compliance alternative does not reduce risks for this major source category. Because we are retaining this compliance alternative, we need not address the comment on the cost effectiveness of removing this alternative.

C. Major Comments Concerning the Technology Review

Comment: One commenter states that, in conducting an 8-year review, the EPA must "look back" at the earlier standard and ascertain whether: (1) The standard was adopted using procedures that comply with the law as it has come to be interpreted by the courts; (2) the EPA had sufficiently accurate and comprehensive data at the time of the initial standard setting respecting the emissions profile of the category and properly identified the best performing unit(s); and (3) the EPA had properly used the available data.

The commenter states the EPA then must "look around" using currently available data and determine whether: (1) The emissions profile of the industry has changed in a way that would substantially affect the MACT floor calculations (the commenter adds that this includes consideration of any increase in the number of good performing units available for use in the existing source MACT floor calculation and in the performance of the best performing unit); (2) data gaps or uncertainties that affected the earlier decision have been resolved in the interim or can be resolved using new information available to the agency; (3) costs or other factors have changed in a way that would substantially affect the "beyond-the-floor" determination; (4) the use of improved practices, processes or technologies (including improvements in the performance of existing technologies) has become more prevalent than at the time of the initial standard setting; or (5) whether newer regulatory requirements, work practices or emission limitations (including state and local jurisdiction air pollution standards and federal enforcement actions), which are more stringent than the existing CAA section 112(d) standard, have shown the achievement or achievability of greater emission reductions than the existing standard requires.

Response: As explained in the preamble to the proposed rule, our technology review focused on the identification and evaluation of "developments in practices, processes, and control technologies" since the promulgation of the MACT standards for the two oil and gas source categories at issue here. We first reviewed the available information. In this regard, we reviewed a variety of sources of data, including data obtained in subsequent air toxics rules to see if any practices, processes and control technologies

considered in these actions could be applied to emission sources in the source categories at issue here. We also consulted the EPA's Reasonably Available Control Technology (RACT)/ Best Available Control Technology (BACT)/Lowest Achievable Emission Rate (LAER) Clearinghouse (RBLC) and the Natural Gas STAR program. At proposal, we explained that we consider any of the following to be a "development":

—Any add-on control technology or other equipment that was not identified and considered during MACT development;

—Any improvements in add-on control technology or other equipment (that was identified and considered during MACT development) that could result in significant additional emission reduction;

—Any work practice or operational procedure that was not identified and considered during MACT development; and

—Any process change or pollution prevention alternative that could be broadly applied that was not identified and considered during MACT development.

The commenter views CAA section 112(d)(6) differently. It appears to argue that CAA section 112(d)(6) requires that the EPA recalculate the MACT based on current data and technology. The same argument was posed to the District of Columbia Circuit, and the Court "[did] not think that the words 'review, and revise as necessary' can be construed reasonably as imposing any such obligation." *NRDC* v. *EPA,* 529 F.3d 1077, 1084 (D.C. Cir. 2008). Thus, contrary to the commenter's assertion, the EPA is not required pursuant to CAA section 112(d)(6) to re-calculate the floors it set in 1999.

To the extent the commenter is arguing that CAA section 112(d)(6) mandates that the EPA correct any deficiency in an underlying MACT standard when it conducts the "technology review" under that section, we disagree. We believe that CAA section 112 does not expressly address this issue, and the EPA has discretion in determining how to address a purported flaw in a promulgated standard. CAA section 112(d)(6) provides that the agency must review and revise "as necessary." The "as necessary" language must be read in the context of the provision, which focuses on the review of developments that have occurred since the time of the original promulgation of the MACT standard and thus should not be read as a mandate to correct flaws that existed at the time of the original promulgation.

In several recent rulemakings, we have chosen to fix underlying defects in existing MACT standards under CAA sections 112(d)(2) and (3), the provisions that directly govern the initial promulgation of MACT standards (see National Emission Standards for Hazardous Air Pollutants From Petroleum Refineries, October 28, 2009, 74 FR 55670; and National Emission Standards for Hazardous Air Pollutants: Group I Polymers and Resins; Marine Tank Vessel Loading Operations; Pharmaceuticals Production; and the Printing and Publishing Industry, April 21, 2011, 76 FR 22566). We believe that our approach is reasonable because using those provisions ensures that the process and considerations are those associated with initially establishing a MACT standard, and it is reasonable to make corrections following the process that would have been followed if we had not made an error at the time of the original promulgation. As explained elsewhere, we are not finalizing MACT standards for the subcategory of storage vessels without the PFE, which were unregulated in the 1999 rule, because after evaluating the available data and comments received, we believe that we need additional data in order to set an emission standard for these vessels. We are, however, finalizing MACT standards under CAA sections 112(d)(2) and (3) for the subcategory of small glycol dehydration units.

With regard to our CAA section 112(d)(6) review, we found no significant developments in practices, processes and control technologies for reducing emissions from large glycol dehydrators and storage vessels with PFE.[29] Accordingly, we are not revising these standards under CAA section 112(d)(6).

The EPA also conducted a technology review evaluating various options for controlling HAP emissions from equipment leaks. As described in the proposed rule (76 FR 52784), we evaluated advancements in controlling this emissions source since the original standards were promulgated, including the emission reduction potential and associated cost-effectiveness of these advancements. As a result of our review, we revised the leak definition for valves at natural gas processing plants to 500 ppm, thus, requiring the application of the LDAR requirement at this lower detection level. As discussed above, the commenter appears to be arguing that the EPA must redo the MACT floor and beyond-the-floor analysis under CAA sections 112(d)(2) and (3) within its CAA section 112(d)(6) technology review, which we disagree.

Comment: One commenter states that the EPA's technology review for storage vessel control technologies is limited and makes incorrect assumptions. The commenter contends that without further support, the public cannot understand and the EPA cannot justify its proposed decision; therefore, the EPA's proposal is arbitrary and capricious. The commenter adds that the EPA must conduct an updated beyond-the-floor analysis for storage vessels, by determining the "maximum degree of reduction in emissions" that is achievable, as required under CAA section 112(d)(2). The commenter states that the proposed rule fails to provide any discussion of a beyond-the-floor determination for storage vessels.

One commenter states that the EPA must examine advances in vapor recovery unit technology and reconsider floating roof technology for tanks containing liquids that do not have the PFE. The commenter contends that the EPA improperly rejected technology advances and developments in pollution prevention systems found in its own RBLC database and employed by its own Natural Gas STAR partners. Specifically, according to the commenter, the EPA failed to evaluate the performance achieved by systems that use thermal or catalytic oxidizers, either alone or in combination with condensers. According to the commenter, the EPA's RBLC review identified a BACT determination for dehydrator efficiency of 98 percent. The commenter also urges the EPA to evaluate the use of combustion devices and vapor recovery units that capture vent steam from the tank and turn it into a saleable product by recompressing the hydrocarbon vapors. The commenter contends that the EPA rejects technology advances by asserting that those technologies were considered in the 1999 rulemaking, but fails to provide support for its decision in either the record of the 1999 rulemaking or the current record. The commenter contends that the EPA must provide a basis for its decisions and conclusions.

Response: For the reasons discussed in the prior response, the EPA disagrees with the commenter's assertion that it must re-do the MACT floor calculations, including the beyond-the-floor determination, for the standards that the agency set in 1999. As to the technologies identified by the commenter, they were in existence and considered by the EPA at the time the EPA promulgated the original MACT

[29] See footnote 25.

standards for storage vessels.[30] [31] In addition, we are not finalizing control requirements for storage vessels without the PFE, as described in section VII.A of this preamble. The record does not support the assertion that the technologies identified by the commenter have advanced in terms of HAP emission reduction or have become significantly more cost effective. As explained in the preamble to the proposed rule (76 FR 52785), we examined technologies that were similar to the cover and route emissions to a control device that the MACT floor requires and, thus, would not result in reductions beyond the existing MACT requirements. Further, evaluation of technologies in the RBLC did not produce any applicable practices, processes or control technologies that were not considered during the original MACT for storage vessels with flash emissions.[32]

D. Major Comments Concerning Notification, Recordkeeping and Reporting Requirements

1. Annual Reports

Comment: One commenter requested that the EPA add a self-certification requirement to the annual report similar to that used in the title V program. The commenter recommended that the final rule require the annual report to include a statement signed by a senior official of the facility attesting to the truth, accuracy and completeness of the report.

The commenter also requested that the EPA require that the annual reports be submitted electronically to facilitate making the reports publicly available. The commenter suggested using social media outlets, smart phone applications and other electronic means to make the annual reports readily available.

Response: The EPA agrees that self-certification is an important mechanism for assuring the public that the information submitted by each facility is accurate. In addition, the title V program has successfully employed self-certification for since its inception. Therefore, we are requiring self-certification, based on requirements in the title V program, in the final rule.

While we agree that having annual reports readily available to the public is a desirable goal, we did not identify any reporting programs or electronic databases that may be used for this purpose without significant modification. Therefore, we are not requiring annual reports to be submitted electronically, but we will continue to evaluate this option in the future.

2. Electronic Reporting of Emissions Data

Several commenters raised similar issues regarding reporting of emissions data under the NESHAP as under the NSPS, described *supra,* and our responses there apply equally here. Please see comments and responses in section IX.F.3 of this preamble.

XI. What are the cost, environmental and economic impacts of the final NESHAP and NSPS amendments?

A. What are the air impacts?

For the oil and natural gas sector NESHAP and NSPS, we estimated the emission reductions that will occur due to the implementation of the final emission limits. The EPA estimated emission reductions based on the control technologies selected by the engineering analysis. These emission reductions associated with the final amendments to 40 CFR part 63, subpart HH and 40 CFR part 63, subpart HHH are based on the estimated population in 2008. Under the finalized limits for glycol dehydration units, we have estimated that the HAP emissions reductions will be 670 tons for existing units subject to the final emissions limits.

For the NSPS, we estimated the emission reductions that will occur due to the implementation of the final emission limits. The EPA estimated emission reductions based on the control technologies selected by the engineering analysis. These emission reductions are based on the estimated population in 2015.

The primary baseline used for the impacts analysis of our NSPS for completions of hydraulically fractured natural gas wells takes into account REC conducted pursuant to state regulations covering these operations and estimates of REC performed voluntarily. To account for REC performed in regulated states, the EPA subsumed emissions reductions and compliance costs in states where these completion-related emissions are already controlled into the baseline. Additionally, based on public comments and reports to the EPA's Natural Gas STAR program, the EPA recognizes that some producers conduct well completions using REC techniques voluntarily for economic and/or environmental objectives as a normal part of business. To account for emissions reductions and costs arising from voluntary implementation of pollution controls, the EPA used information on total emission reductions reported to the EPA by partners of the EPA Natural Gas STAR. This estimate of this voluntary REC activity in the absence of regulation is also included in the baseline.[33] More detailed discussion on the derivation of the baseline is presented in a technical memorandum in the docket, as well as in the Regulatory Impact Analysis (RIA).

Additionally, in the RIA, we provide summary-level estimates of emissions reductions and engineering compliance costs for a case where no voluntary REC are assumed to occur. This alternative case is presented in order to show impacts if conditions were such that REC were no longer performed on a voluntary basis, but, rather, were compelled by the regulation, and serves, in part, to capture the inherent uncertainty in projecting voluntary activity into the future. As such, this alternative case establishes the full universe of emissions reductions that are guaranteed by this NSPS (those that are required to occur under the rule, including those that would likely occur voluntarily). While the primary baseline may better represent actual costs (and emissions reductions) beyond those already expected under business as usual, the alternative case better captures the full amount of emissions reductions where the NSPS acts as a backstop to ensure that emission reduction practices occur (practices covered by this rule).

Under the final NSPS, we have estimated that the emissions reductions to be about 190,000 tons VOC affected facilities subject to the NSPS. The NSPS is also expected to concurrently reduce 1.0 million tons methane and 11,000 tons HAP. We estimate that direct reductions in HAP, methane and VOC for the final rules combined total about 12,000 tons, 1.0 million tons and 190,000 tons, respectively. If voluntary action is not deducted from the NSPS baseline, the emissions reductions achieved by the final NSPS in HAP, methane and VOC are estimated at

[30] See footnote 25.

[31] See EPA Legacy Docket A–94–04 MACT floor memos II–A–006 and –007.

[32] See footnote 25.

[33] Voluntary short-term actions (such as REC) are challenging to capture accurately in a prospective analysis, as such, reductions are not guaranteed to continue. However, Natural Gas STAR represents a nearly 20-year voluntary initiative with participation from 124 natural gas companies operating in the United States, including 28 producers, over a wide historical range of natural gas prices. This unique program and dataset, the significant impact of voluntary REC on the projected cost and emissions reductions (due to significant REC activity), and the fact that REC can actually increase natural gas recovered from natural gas wells (offering a clear incentive to continue the practice), led the agency to conclude that it was appropriate to estimate these particular voluntary actions in the baseline for this rule.

about 19,000 tons, 1.7 million tons and 290,000 tons, respectively.

The EPA received several comments regarding the emission factor selected to calculate whole gas emissions (and the associated VOC emissions) from hydraulically fractured well completions. Comments focused on the data behind the emission factor, what the emission factor is intended to represent and the procedures used to develop the emission factor from the selected data sets. We reviewed all information received and have decided to retain the data set and the analysis conducted to develop the emission factor of 9,000 thousand cubic feet (Mcf) per completion. More detailed discussion is presented in a technical memorandum on this subject in the docket.

B. What are the energy impacts?

Energy impacts in this section are those energy requirements associated with the operation of emission control devices. Potential impacts on the national energy economy from the rule are discussed in the economic impacts section. There would be little national energy demand increase from the operation of any of the environmental controls analyzed under the final NESHAP amendments and final NSPS.

The final NESHAP amendments and final NSPS encourage the use of emission controls that recover hydrocarbon products, such as methane and condensate that can be used on-site as fuel or reprocessed within the production process for sale. We estimated that the final standards will result in net annual costs savings of about $11 million (in 2008 dollars) due to the recovery of salable natural gas and condensate. Thus, the final standards have a positive impact associated with the recovery of non-renewable energy resources.

C. What are the cost impacts?

The estimated total capital cost to comply with the final amendments to 40 CFR part 63, subpart HH for major sources in the Oil and Natural Gas Production source category is approximately $2.6 million. The total capital cost for the final amendments to 40 CFR part 63, subpart HHH for major sources in the Natural Gas Transmission and Storage source category is estimated to be approximately $140,000. All costs are in 2008 dollars.

The total estimated net annual cost to industry to comply with the final amendments to 40 CFR part 63, subpart HH for major sources in the Oil and Natural Gas Production source category is approximately $3.3 million. The total net annual cost for final amendments to 40 CFR part 63, subpart HHH for major sources in the Natural Gas Transmission and Storage source category is estimated to be approximately $180,000. These estimated annual costs include: (1) The cost of capital, (2) operating and maintenance costs, (3) the cost of monitoring, inspection, recordkeeping and reporting (MIRR) and (4) any associated product recovery credits. All costs are in 2008 dollars.

The estimated total capital cost to comply with the final NSPS is approximately $25 million in 2008 dollars. The total estimated net annual cost to industry to comply with the final NSPS is estimated to be approximately $170 million in 2008 dollars. This annual cost estimate includes: (1) The cost of capital, (2) operating and maintenance costs and (3) the cost of MIRR. This estimated annual cost does not take into account any producer revenues associated with the recovery of salable natural gas and hydrocarbon condensates.

When revenues from additional product recovery are considered, the final NSPS is estimated to result in a net annual engineering cost savings overall. When including the additional natural gas recovery in the engineering cost analysis, we assume that producers are paid $4/Mcf for the recovered gas at the wellhead. The engineering analysis cost analysis assumes the value of recovered condensate is $70 per barrel. Based on the engineering analysis, about 43 million Mcf (43 billion cubic feet) of natural gas and 160,000 barrels of condensate are estimated to be recovered by control requirements in 2015. Using the price assumptions, the estimated revenues from natural gas and condensate recovery are approximately $180 million in 2008 dollars.

Using the engineering cost estimates, estimated natural gas product recovery and natural gas product price assumptions, the net annual engineering cost savings is estimated for the final NSPS to be about $15 million. Totals may not sum due to independent rounding.

If voluntary action is not deducted from the baseline, capital costs for the NSPS are estimated at $25 million and annualized costs without revenues from product recovery for the NSPS are estimated at $330 million. In this scenario, given the assumptions about product prices, estimated revenues from product recovery are $350 million, yielding an estimated cost of savings of about $22 million.

As the price assumption is very influential on estimated annualized engineering costs, we performed a simple sensitivity analysis of the influence of the assumed wellhead price paid to natural gas producers on the overall engineering annualized costs estimate of the final NSPS. At $4.22/Mcf, the price forecast reported in the 2011 Annual Energy Outlook in 2008 dollars, the annualized cost savings for the final NSPS are estimated at about $24 million. As indicated by this difference, the EPA has chosen a relatively conservative assumption (leading to an estimate of few savings and higher net costs) for the engineering costs analysis. The natural gas price at which the final NSPS breaks-even from an estimated engineering costs perspective is around $3.66/Mcf. A $1/Mcf change in the wellhead natural gas price leads to a $43 million change in the annualized engineering costs of the final NSPS. Consequently, annualized engineering costs estimates would increase to about $29 million under a $3/Mcf price or decrease to about −$58 million under a $5/Mcf price. For further details on this sensitivity analysis, please refer the RIA for this rulemaking located in the docket.

D. What are the economic impacts?

The analysis of energy system impacts EPA performed using the United States Department of Energy's (DOE) National Energy Modeling System (NEMS) shows that domestic natural gas production is not likely to change in 2015 as a result of the final rules, the year used in the RIA to analyze impacts. Average natural gas prices are also not estimated to change in response to the final rules. Domestic crude oil production is not expected to change, while average crude oil prices are estimated to decrease slightly (about $0.01/barrel or about 0.01 percent at the wellhead for onshore production in the lower 48 states). All prices are in 2008 dollars. The NEMS-based analysis estimates in the year of analysis, 2015, that net imports of natural gas and crude oil will not change.

E. What are the benefits of this final rule?

The final Oil and Natural Gas NSPS and NESHAP amendments are expected to result in significant reductions in existing emissions and prevent new emissions from expansions of the industry. These final rules combined are anticipated to reduce 12,000 tons of HAP, 190,000 tons of VOC (a precursor to both PM (2.5 microns and less) ($PM_{2.5}$) and ozone formation) and 1.0 million tons of methane (a GHG and a precursor to global ozone formation). These pollutants are associated with

substantial health effects, welfare effects and climate effects.

With the data available, we are not able to provide credible health benefit estimates for the reduction in exposure to HAP, ozone and $PM_{2.5}$ for these rules, due to the differences in the locations of oil and natural gas emission points relative to existing information and the highly localized nature of air quality responses associated with HAP and VOC reductions. This is not to imply that there are no benefits of the rules; rather, it is a reflection of the difficulties in modeling the direct and indirect impacts of the reductions in emissions for this industrial sector with the data currently available.[34] In addition to health improvements, there will be improvements in visibility effects, ecosystem effects and climate effects, as well as additional product recovery.

Although we do not have sufficient information or modeling available to provide quantitative estimates for this rulemaking, we include a qualitative assessment of the health effects associated with exposure to HAP, ozone and $PM_{2.5}$ in the RIA for this rule. These qualitative effects are briefly summarized below, but for more detailed information, please refer to the RIA, which is available in the docket. One of the HAP of concern from the oil and natural gas sector is benzene, which is a known human carcinogen. VOC emissions are precursors to both $PM_{2.5}$ and ozone formation. As documented in previous analyses (U.S. EPA, 2006[35] and U.S. EPA, 2010[36]), exposure to $PM_{2.5}$ and ozone is associated with significant public health effects. $PM_{2.5}$ is associated with health effects, including premature mortality for adults and infants, cardiovascular morbidity such as heart attacks, and respiratory morbidity such as asthma attacks, acute and chronic bronchitis, hospital admissions and emergency room visits, work loss days, restricted activity days and respiratory symptoms, as well as visibility impairment.[37] Ozone is associated with health effects, including hospital and emergency department visits, school loss days and premature mortality, as well as injury to vegetation and climate effects.[38]

In addition to the improvements in air quality and resulting benefits to human health and non-climate welfare effects previously discussed, this rule is expected to result in significant climate co-benefits due to anticipated methane reductions. Methane is a potent GHG that, once emitted into the atmosphere, absorbs terrestrial infrared radiation, which contributes to increased global warming and continuing climate change. Methane reacts in the atmosphere to form ozone and ozone also impacts global temperatures. According to the Intergovernmental Panel on Climate Change (IPCC) 4th Assessment Report (2007), methane is the second leading long-lived climate forcer after CO_2 globally. Total methane emissions from the oil and gas industry represent about 40 percent of the total methane emissions from all sources and account for about 5 percent of all CO_2e emissions in the United States, with natural gas systems being the single largest contributor to United States anthropogenic methane emissions.[39] Methane, in addition to other GHG emissions, contributes to warming of the atmosphere, which, over time, leads to increased air and ocean temperatures, changes in precipitation patterns, melting and thawing of global glaciers and ice, increasingly severe weather events, such as hurricanes of greater intensity and sea level rise, among other impacts.

This rulemaking requires emission control technologies and regulatory alternatives that will significantly decrease HAP and VOC emissions from the oil and natural gas sector in the United States. As a co-benefit, the emission control measures the industry will use to reduce HAP and VOC emissions will also decrease methane emissions. The NESHAP Amendments and the NSPS combined are expected to reduce methane emissions annually by about 1.0 million short tons or about 19 million metric tons CO_2e. After considering the secondary impacts of this rule as previously discussed, such as increased CO_2 emissions from well completion combustion and decreased CO_2e emissions because of fuel-switching by consumers, the methane reductions become about 18 million metric tons CO_2e. The methane reductions represent about 7 percent of the baseline methane emissions for this sector reported in the EPA's U.S. Greenhouse Gas Inventory Report for 2009 (251.55 million metric tons CO_2e when petroleum refineries and petroleum transportation are excluded because these sources are not examined in this proposal). However, it is important to note that the emission reductions are based upon predicted activities in 2015; the EPA did not forecast sector-level emissions in 2015 for this rulemaking. These emission reductions equate to the climate benefits of taking approximately 4 million typical passenger cars off the road or eliminating electricity use from about 2 million typical homes each year.[40]

The EPA recognizes that the methane reductions from this rule will provide for significant economic climate benefits to society just described. However, the 2009–2010 Interagency Social Cost of Carbon Work Group did not produce directly modeled estimates of the social cost of methane. In the absence of direct model estimates from the interagency analysis, the EPA has used a "global warming potential (GWP) approach" to estimate the dollar value of this rule's methane co-benefits. Specifically, the EPA converted methane to CO_2 equivalents using the GWP of methane, then multiplied these CO_2 equivalent emission reductions by the social cost of carbon developed by the Interagency Social Cost of Carbon Work Group.

The social cost of carbon is an estimate of the net present value of the flow of monetized damages from a 1-metric ton increase in CO_2 emissions in

[34] Previous studies have estimated the monetized benefits-per-ton of reducing VOC emissions associated with the effect that those emissions have on ambient $PM_{2.5}$ levels and the health effects associated with $PM_{2.5}$ exposure (Fann, Fulcher, and Hubbell, 2009). While these ranges of benefit-per-ton estimates provide useful context for the break-even analysis, the geographic distribution of VOC emissions from the oil and gas sector are not consistent with emissions modeled in Fann, Fulcher, and Hubbell (2009). In addition, the benefit-per-ton estimates for VOC emission reductions in that study are derived from total VOC emissions across all sectors. Coupled with the larger uncertainties about the relationship between VOC emissions and $PM_{2.5}$ and the highly localized nature of air quality responses associated with HAP and VOC reductions, these factors lead us to conclude that the available VOC benefit-per-ton estimates are not appropriate to calculate monetized benefits of these rules, even as a bounding exercise.

[35] U.S. EPA. RIA. *National Ambient Air Quality Standards for Particulate Matter*, Chapter 5. Office of Air Quality Planning and Standards, Research Triangle Park, NC. October 2006. Available on the Internet at *http://www.epa.gov/ttn/ecas/regdata/RIAs/Chapter%205--Benefits.pdf.*

[36] U.S. EPA. RIA. *National Ambient Air Quality Standards for Ozone.* Office of Air Quality Planning and Standards, Research Triangle Park, NC. January 2010. Available on the Internet at *http://www.epa.gov/ttn/ecas/regdata/RIAs/s1-supplemental_analysis_full.pdf.*

[37] U.S. EPA. *Integrated Science Assessment for Particulate Matter (Final Report).* EPA–600–R–08–139F. National Center for Environmental Assessment—RTP Division. December 2009. Available at *http://cfpub.epa.gov/ncea/cfm/recordisplay.cfm?deid=216546.*

[38] U.S. EPA. *Air Quality Criteria for Ozone and Related Photochemical Oxidants (Final).* EPA/600/R–05/004aF-cF. Washington, DC: U.S. EPA. February 2006. Available on the Internet at *http://cfpub.epa.gov/ncea/CFM/recordisplay.cfm?deid=149923.*

[39] U.S. EPA (2011), *2011 U.S. Greenhouse Gas Inventory Report* Executive Summary available on the internet at *http://epa.gov/climatechange/emissions/downloads11/US-GHG-Inventory-2011–Executive-Summary.pdf,* accessed 02/13/12.

[40] U.S. EPA. *Greenhouse Gas Equivalency Calculator* available at: *http://www.epa.gov/cleanenergy/energy-resources/calculator.html,* accessed 04/09/12.

a given year (or from the alternative perspective, the benefit to society of reducing CO_2 emissions by 1 ton). For more information about the social cost of carbon, see the *Support Document: Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866.*[41] Applying this approach to the methane reductions estimated for the NESHAP Amendments and NSPS, the 2015 climate co-benefits vary by discount rate and range from about $100 million to approximately $1.3 billion; the mean social cost of carbon at the 3-percent discount rate results in an estimate of about $440 million in 2015.[42]

These co-benefits equate to a range of approximately $110 to $1,400 per short ton of methane reduced, depending upon the discount rate assumed with a per ton estimate of $480 at the 3-percent discount rate. These social cost of methane benefit estimates are not the same as would be derived from direct computations (using the integrated assessment models employed to develop the Interagency Social Cost of Carbon estimates) for a variety of reasons, including the shorter atmospheric lifetime of methane relative to CO_2 (about 12 years compared to CO_2 whose concentrations in the atmosphere decay on timescales of decades to millennia). The climate impacts also differ between the pollutants for reasons other than the radiative forcing profiles and atmospheric lifetimes of these gases.

Methane is a precursor to ozone and ozone is a short-lived climate forcer that contributes to global warming. The use of the IPCC Second Assessment Report GWP to approximate co-benefits may underestimate the direct radiative forcing benefits of reduced ozone levels and does not capture any secondary climate co-benefits involved with ozone-ecosystem interactions. In addition, a recent the EPA National Center of Environmental Economics working paper suggests that this quick ''GWP approach'' to benefits estimation will likely understate the climate benefits of methane reductions in most cases.[43] This conclusion is reached using the 100-year GWP for methane of 25 as put forth in the IPCC Fourth Assessment Report (AR 4), as opposed to the lower value of 21 used in this analysis. Using the higher GWP estimate of 25 would increase these reported methane climate co-benefit estimates by about 19 percent. Although the IPCC Assessment Report (AR4) suggested a GWP of 25 for methane, the EPA has used the GWP of 21 from the IPCC Second Assessment Report to estimate the methane climate co-benefits for this oil and gas rule. The EPA uses the 21 GWP in order to provide estimates more consistent with global GHG inventories, which currently use GWP from the IPCC Second Assessment Report, and with the US GHG Reporting program. See the Regulatory Impact Analysis for further details.

Due to the uncertainties involved with the ''GWP approach'' estimates presented and methane climate co-benefits estimates available in the literature, the EPA chooses not to compare these co-benefit estimates to the costs of the rule for this proposal. Rather, the EPA presents the ''GWP approach'' climate co-benefit estimates as an interim method to produce these estimates until the Interagency Social Cost of Carbon Work Group develops values for non-CO_2 GHG.

For the final NESHAP amendments, a break-even analysis suggests that HAP emissions would need to be valued at $5,200 per ton for the benefits to exceed the costs if the health, ecosystem and climate benefits from the reductions in VOC and methane emissions are assumed to be zero. Even though emission reductions of VOC and methane are co-benefits for the final NESHAP amendments, they are legitimate components of the total benefit-cost comparison. If we assume the health benefits from HAP emission reductions are zero, the VOC emissions would need to be valued at $2,900 per ton or the methane emissions would need to be valued at $8,300 per ton for the co-benefits to exceed the costs. All estimates are in 2008 dollars. For the final NSPS, the revenue from additional product recovery exceeds the costs, which renders a break-even analysis unnecessary when these revenues are included in the analysis. Based on the methodology from Fann, Fulcher, and Hubbell (2009),[44] ranges of benefit-per-ton estimates for emissions of VOC indicate that on average in the United States, VOC emissions are valued from $1,200 to $3,000 per ton as a $PM_{2.5}$ precursor, but emission reductions in specific areas are valued from $280 to $7,000 per ton in 2008 dollars. As a result, even if VOC emissions from oil and natural gas operations result in monetized benefits that are substantially below the national average, there is a reasonable chance that the benefits of the rule would exceed the costs, especially if we were able to monetize all of the additional benefits associated with ozone formation, visibility, HAP and methane.

XII. Statutory and Executive Order Reviews

A. Executive Order 12866, Regulatory Planning and Review and Executive Order 13563, Improving Regulation and Regulatory Review

Under section 3(f)(1) of Executive Order 12866 (58 FR 51735, October 4, 1993), this action is an ''economically significant regulatory action'' because it is likely to have an annual effect on the economy of $100 million or more. Accordingly, the EPA submitted this action to the Office of Management and Budget (OMB) for review under Executive Order 12866 and Executive Order 13563 (76 FR 3821, January 21, 2011), and any changes made in response to OMB recommendations have been documented in the docket for this action.

In addition, the EPA prepared a Regulatory Impact Analysis (RIA) of the potential costs and benefits associated with this action. The RIA available in the docket describes in detail the empirical basis for the EPA's assumptions and characterizes the various sources of uncertainties affecting the estimates below. Table 7 shows the results of the cost and benefits analysis for these final rules.

[41] Interagency Working Group on Social Cost of Carbon (IWGSC). 2010. *Technical Support Document: Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866.* Docket ID EPA–HQ–OAR–2009–0472–114577. *http://www.epa.gov/otaq/climate/regulations/scc-tsd.pdf,* accessed 02/12/12.

[42] The ratio of domestic to global benefits of emission reductions varies with key parameter assumptions. See Interagency Working Group on Social Cost of Carbon. 2010. *Technical Support Document: Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866.*

[43] Marten and Newbold (2011), *Estimating the Social Cost of Non-CO_2 GHG Emissions: Methane and Nitrous Oxide,* NCEE Working Paper Series #11–01. *http://yosemite.epa.gov/EE/epa/eed.nsf/WPNumber/2011-01?OpenDocument.*

[44] Fann, N., C.M. Fulcher, B.J. Hubbell. *The influence of location, source, and emission type in estimates of the human health benefits of reducing a ton of air pollution.* Air Qual Atmos Health (2009) 2:169–176.

TABLE 7—SUMMARY OF THE MONETIZED BENEFITS, SOCIAL COSTS AND NET BENEFITS FOR THE FINAL OIL AND NATURAL GAS NSPS AND NESHAP AMENDMENTS IN 2015

[Millions of 2008$] [1]

	Final NSPS	Final NESHAP amendments	Final NSPS and NESHAP amendments combined
Total Monetized Benefits [2]	N/A	N/A	N/A.
Total Costs [3]	−$15 million	$3.5 million	−$11 million.
Net Benefits	N/A	N/A	N/A.
Non-monetized Benefits [4]	11,000 tons of HAP 190,000 tons of VOC 1.0 million tons of methane	670 tons of HAP 1,200 tons of VOC 420 tons of methane	12,000 tons of HAP. 190,000 tons of VOC. 1.0 million tons of methane.
	Health effects of HAP exposure. Health effects of $PM_{2.5}$ and ozone exposure. Visibility impairment. Vegetation effects. Climate effects.		

[1] All estimates are for the implementation year (2015).

[2] While we expect that these avoided emissions will result in improvements in air quality and reductions in health effects associated with HAP, ozone, and particulate matter (PM) as well as climate effects associated with methane, we have determined that quantification of those benefits and co-benefits cannot be accomplished for this rule in a defensible way. This is not to imply that there are no benefits or co-benefits of the rules; rather, it is a reflection of the difficulties in modeling the direct and indirect impacts of the reductions in emissions for this industrial sector with the data currently available.

[3] The engineering compliance costs are annualized using a 7-percent discount rate. The negative cost for the final NSPS reflects the inclusion of revenues from additional natural gas and hydrocarbon condensate recovery that are estimated as a result of the NSPS. Possible explanations for why there appear to be negative cost control technologies are discussed in the engineering costs analysis section in the RIA.

[4] For the NSPS, reduced exposure to HAP and climate effects are co-benefits. For the NESHAP, reduced VOC emissions, $PM_{2.5}$ and ozone exposure, visibility and vegetation effects and climate effects are co-benefits. The specific control technologies for the final NSPS are anticipated to have minor secondary disbenefits, including an increase of 1.1 million tons of carbon dioxide (CO_2), 550 tons of nitrogen oxides (NO_X), 19 tons of PM, 3,000 tons of CO and 1,100 tons of total hydrocarbons (THC), as well as emission reductions associated with the energy system impacts. The specific control technologies for the NESHAP are anticipated to have minor secondary disbenefits, but the EPA was unable to estimate these secondary disbenefits. The net CO_2-equivalent emission reductions are 18 million metric tons.

B. Paperwork Reduction Act

The information collection requirements in this rule have been submitted for approval to the Office of Management and Budget (OMB) under the *Paperwork Reduction Act,* 44 U.S.C. 3501, *et seq.* The information collection requirements are not enforceable until OMB approves them.

The ICR documents prepared by the EPA have been assigned EPA ICR numbers 2437.01, 2438.01, 2439.01 and 2440.01. The information requirements are based on notification, recordkeeping and reporting requirements in the NESHAP General Provisions (40 CFR part 63, subpart A), which are mandatory for all operators subject to national emission standards. These recordkeeping and reporting requirements are specifically authorized by CAA section 114 (42 U.S.C. 7414). All information submitted to the EPA pursuant to the recordkeeping and reporting requirements for which a claim of confidentiality is made is safeguarded according to Agency policies set forth in 40 CFR part 2, subpart B. This final rule requires maintenance inspections of the control devices but would not require any notifications or reports beyond those required by the General Provisions. The recordkeeping requirements require only the specific information needed to determine compliance.

When a malfunction occurs, sources must report them according to the applicable reporting requirements of 40 CFR part 63, subpart HH or 40 CFR part 63, subpart HHH. An affirmative defense to civil penalties for exceedances of emission limits that are caused by malfunctions is available to a source if it can demonstrate that certain criteria and requirements are satisfied. The criteria ensure that the affirmative defense is available only where the event that causes an exceedance of the emission limit meets the narrow definition of malfunction in 40 CFR 63.2 (sudden, infrequent, not reasonable preventable, and not caused by poor maintenance and/or careless operation) and where the source took necessary actions to minimize emissions. In addition, the source must meet certain notification and reporting requirements. For example, the source must prepare a written root cause analysis and submit a written report to the Administrator documenting that it has met the conditions and requirements for assertion of the affirmative defense.

For this rule, the EPA is adding affirmative defense to the estimate of burden in the ICR. To provide the public with an estimate of the relative magnitude of the burden associated with an assertion of the affirmative defense position adopted by a source, the EPA has provided administrative adjustments to this ICR that shows what the notification, recordkeeping and reporting requirements associated with the assertion of the affirmative defense might entail. The EPA's estimate for the required notification, reports, and records, including the root cause analysis, associated with a single incident totals approximately totals $3,141 and is based on the time and effort required of a source to review relevant data, interview plant employees, and document the events surrounding a malfunction that has caused an exceedance of an emission limit. The estimate also includes time to produce and retain the record and reports for submission to the EPA. The EPA provides this illustrative estimate of this burden, because these costs are only incurred if there has been a violation, and a source chooses to take advantage of the affirmative defense.

The EPA provides this illustrative estimate of this burden because these costs are only incurred if there has been a violation and a source chooses to take advantage of the affirmative defense. Given the variety of circumstances under which malfunctions could occur, as well as differences among sources' operation and maintenance practices, we cannot reliably predict the severity and frequency of malfunction-related excess emissions events for a particular source. It is important to note that the

EPA has no basis currently for estimating the number of malfunctions that would qualify for an affirmative defense. Current historical records would be an inappropriate basis, as source owners or operators previously operated their facilities in recognition that they were exempt from the requirement to comply with emissions standards during malfunctions. Of the number of excess emissions events reported by source operators, only a small number would be expected to result from a malfunction (based on the definition above), and only a subset of excess emissions caused by malfunctions would result in the source choosing to assert the affirmative defense. Thus, we believe the number of instances in which source operators might be expected to avail themselves of the affirmative defense will be extremely small.

For this reason, we estimate a total of 39 such occurrences for all sources subject to 40 CFR part 63, subpart HH, a total of three such occurrences for all sources subject to 40 CFR part 63, subpart HHH, and a total of 6 such occurrences for all sources subject to 40 CFR part 60, subparts KKK and LLL over the 3-year period covered by this ICR. We expect to gather information on such events in the future, and will revise this estimate as better information becomes available.

The annual monitoring, reporting, and recordkeeping burden for this collection (averaged over the first 3 years after the effective date of the standards) is estimated to be $20.1 million. This includes 384,866 labor hours per year at a total labor cost of $19.5 million per year, and annualized capital costs of $0.36 million, and annual operating and maintenance costs of $0.20 million. This estimate includes initial and annual performance tests, semiannual excess emission reports, developing a monitoring plan, notifications and recordkeeping. All burden estimates are in 2008 dollars and represent the most cost-effective monitoring approach for affected facilities. Burden is defined at 5 CFR 1320.3(b).

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for the EPA's regulations in 40 CFR are listed in 40 CFR part 9. When these ICR are approved by OMB, the agency will publish a technical amendment to 40 CFR part 9 in the **Federal Register** to display the OMB control numbers for the approved information collection requirements contained in the final rule.

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 will not have a significant economic impact on a substantial number of small entities (SISNOSE). Small entities include small businesses, small organizations, and small governmental jurisdictions. For purposes of assessing the impact of this rule on small entities, a small entity is defined as: (1) A small business as defined by NAICS codes 211111, 211112, 221210, 486110 and 486210; whose parent company has no more than 500 employees (or revenues of less than $7 million for firms that transport natural gas via pipeline); (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.

For the final NSPS, the EPA performed an analysis for impacts on a sample of expected affected small entities by comparing compliance costs to entity revenues. The baseline used in this analysis takes into account REC conducted pursuant to state regulations covering these operations and estimates of REC performed voluntarily. To account for REC performed in regulated states, the EPA subsumed emissions reductions and compliance costs in states where these completion-related emissions are already controlled into the baseline. Additionally, based on public comments and reports to the EPA's Natural Gas STAR program, the EPA recognizes that some producers conduct well completions using REC techniques voluntarily for economic and/or environmental objectives as a normal part of business. To account for emissions reductions and costs arising from voluntary implementation of pollution controls, the EPA used information on total emission reductions reported to the EPA by partners of the EPA Natural Gas STAR. This estimate of this voluntary REC activity in the absence of regulation is also included in the baseline. More detailed discussion on the derivation of the baseline is presented in a technical memorandum in the docket, as well as in the RIA.

Based upon the analysis in the RIA, which is in the Docket, when revenue from additional natural gas product recovered is not included, we estimate that 123 of the 127 small firms analyzed (97 percent) are likely to have impacts less than 1 percent in terms of the ratio of annualized compliance costs to revenues. Meanwhile, four firms (3 percent) are likely to have impacts greater than 1 percent. Three of these four firms are likely to have impacts greater than 3 percent. However, when revenue from additional natural gas product recovery is included, we estimate that none of the analyzed firms will have an impact greater than 1 percent.

For the final NESHAP amendments, we estimate that 11 of the 35 firms (31 percent) that own potentially affected facilities are small entities. The EPA performed an analysis for impacts on all expected affected small entities by comparing compliance costs to entity revenues. Among the small firms, none are likely to have impacts greater than 1 percent in terms of the ratio of annualized compliance costs to revenues.

After considering the economic impact of the combined NSPS and NESHAP amendments on small entities, I certify this action will not have a significant impact on a substantial number of small entities (SISNOSE). While both the NSPS and NESHAP amendment would individually result in a no SISNOSE finding, the EPA performed an additional analysis in order to certify the rule in its entirety. This analysis compared compliance costs to entity revenues for the total of all the entities affected by the NESHAP amendments and the sample of entities analyzed for the NSPS. When revenues from additional natural gas product sales are not included, 132 of the 136 small firms (97 percent) in the sample are likely to have impacts of less than 1 percent in terms of the ratio of annualized compliance costs to revenues. Meanwhile, four firms (3 percent) are likely to have impacts greater than 1 percent. Three of these four firms are likely to have impacts greater than 3 percent. When revenues from additional natural gas product sales are included, none of the 136 small firms (100 percent) are likely to have impacts greater than 1 percent.

Our determination is informed by the fact that many affected firms are expected to receive revenues from the additional natural gas and condensate recovery engendered by the implementation of the controls evaluated in this RIA. As much of the additional natural gas recovery is estimated to arise from completion-related activities, we expect the impact

on well-related compliance costs to be significantly mitigated. This conclusion is enhanced because the returns to REC activities occur without a significant time lag between implementing the control and obtaining the recovered product, unlike many control options where the emissions reductions accumulate over long periods of time; the reduced emission completions occur over a short span of time, during which the additional product recovery is also accomplished and payments for recovered products are settled.

Although this final rule will not impact a substantial number of small entities, the EPA, nonetheless, has tried to reduce the impact of this rule on small entities by setting the final emissions limits at the MACT floor, the least stringent level allowed by law.

D. Unfunded Mandates Reform Act

This final action does not contain a federal mandate under the provisions of Title II of the Unfunded Mandates Reform Act of 1995 (UMRA), 2 U.S.C. 1531–1538 for state, local, and tribal governments, in the aggregate, or to the private sector. The action would not result in expenditures of $100 million or more for state, local, and tribal governments, in the aggregate, or to the private sector in any 1 year. Thus, this final rule is not subject to the requirements of sections 202 or 205 of UMRA.

This final 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 because it contains no requirements that apply to such governments nor does it impose obligations upon them.

E. Executive Order 13132: Federalism

This action 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. These final rules primarily affect private industry, and do not impose significant economic costs on state or local governments. On the contrary, we believe the modification provisions discussed in section IX.A for well completions conducted at gas wells constructed on or before August 23, 2011, will reduce permitting burden borne by the States. These provisions will result in fewer sources becoming affected facilities under the NSPS while achieving emission reductions beginning October 15, 2012 equal to those achieved by new sources beginning January 1, 2015. Thus, Executive Order 13132 does not apply to this action.

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

Subject to the Executive Order 13175 (65 FR 67249, November 9, 2000) the EPA may not issue a regulation that has tribal implications, that imposes substantial direct compliance costs, and that is not required by statute, unless the Federal government provides the funds necessary to pay the direct compliance costs incurred by tribal governments, or the EPA consults with tribal officials early in the process of developing the proposed regulation and develops a tribal summary impact statement.

The EPA has concluded that this action will not have tribal implications because it doesn't impose a significant cost to the tribal government. However, there are significant tribal interests because of the growth of the oil and gas production industry in Indian country.

The EPA initiated a consultation process with tribal officials early in the process of developing this regulation to permit them to have meaningful and timely input into its development. During the consultation process, the EPA conducted outreach and information meetings prior to the proposal in 2010. The EPA met with the Inter Tribal Environmental Council, which include many of the Region VI tribes, The Tribal leadership summit in Region X, and Tribal Energy Conference hosted by Ft. Belknap, and the National Tribal Forum.

After the proposal was published, letters were sent to all tribal leaders offering to consult on a government-to-government basis on the rule. As part of the consultation process and in response to these letters, an outreach call was held on October 12, 2011. Tribes that participated on this call were: Fond du Lac Band of Lake Superior Chippewa, Fort Belknap Indian Community, Forest County Potawatomi Community, Southern Ute Indian Tribe, and Pueblo of Santa Clara.

In this meeting the tribes were presented the information in the proposal. The tribes asked general clarifying questions but did not provide specific comments. Comments on the proposal were received from an affiliate of the Southern Ute Indian Tribe. The commenter expressed concern about the impacts of the rule on natural gas and oil production operations on the Southern Ute Indian reservation and requested additional time to evaluate the impacts. In response to this and other requests, the comment period was extended. More specific comments can be found in the docket.

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

This action is not subject to Executive Order 13045 (62 FR 19885, April 23, 1997) because the Agency does not believe the environmental health risks or safety risks addressed by this action present a disproportionate risk to children. This action would not relax the control measures on existing regulated sources. The EPA's risk assessments (included in the docket for this final rule) demonstrate that the existing regulations are associated with an acceptable level of risk and provide an ample margin of safety to protect public health.

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

This action 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. These final rules will result in the addition of control equipment and monitoring systems for existing and new sources within the oil and natural gas industry. The final NESHAP amendments are unlikely to have a significant adverse effect on the supply, distribution, or use of energy. As such, the final NESHAP amendments are not "significant energy actions" as defined in Executive Order 13211, (66 FR 28355, May 22, 2001). The final NSPS is also unlikely to have a significant adverse effect on the supply, distribution, or use of energy. As such, the final NSPS is not a "significant energy action" as defined in Executive Order 13211 (66 FR 28355, May 22, 2001).

The basis for these determinations is as follows. Emission controls for the NSPS capture VOC emissions that otherwise would be vented to the atmosphere. Since methane is co-emitted with VOC, a large proportion of the averted methane emissions can be directed into natural gas production streams and sold. One pollution control requirement of the final NSPS also captures saleable condensates. The revenues from additional natural gas and condensate recovery are expected to offset the costs of implementing the final rules.

We use the NEMS to estimate the impacts of the combined final rules on

the United States energy system. The NEMS is a publically available model of the United States energy economy developed and maintained by the Energy Information Administration of the DOE and is used to produce the Annual Energy Outlook, a reference publication that provides detailed forecasts of the United States energy economy.

Based on public comments and reports to EPA's Natural Gas STAR program, the EPA recognizes that some producers conduct well completions using REC techniques, which are required by the final NSPS for certain completions of hydraulically fractured and refractured natural gas wells, voluntarily based upon economic and environmental objectives. The baseline used for the energy system impacts analysis takes into account REC conducted pursuant to state regulations covering these operations and estimates of REC performed voluntarily. To account for REC performed in regulated states, the EPA subsumed emissions reductions and compliance costs in states where these completion-related emissions are already controlled into the baseline. Additionally, based on public comments and reports to the EPA's Natural Gas STAR program, the EPA recognizes that some producers conduct well completions using REC techniques voluntarily for economic and/or environmental objectives as a normal part of business. To account for emissions reductions and costs arising from voluntary implementation of pollution controls, the EPA used information on total emission reductions reported to the EPA by partners of the EPA Natural Gas STAR. This estimate of this voluntary REC activity in the absence of regulation is also included in the baseline. More detailed discussion on the derivation of the baseline is presented in a technical memorandum in the docket, as well as in the RIA.

The analysis of energy system impacts for the final NSPS under the primary baseline shows that domestic natural gas production is not likely to change in 2015, the year used in the RIA to analyze impacts. Average natural gas prices are also not estimated to change in response to the final rules. Domestic crude oil production is not expected to change, while average crude oil prices are estimated to decrease slightly (about $0.01/barrel or about 0.01 percent at the wellhead for onshore production in the lower 48 states). All prices are in 2008 dollars. The NEMS-based analysis estimates in the year of analysis, 2015, that net imports of natural gas and crude oil will not change.

Additionally, the NSPS establishes several performance standards that give regulated entities flexibility in determining how to best comply with the regulation. In an industry that is geographically and economically heterogeneous, this flexibility is an important factor in reducing regulatory burden.

For more information on the estimated energy effects, please refer to the economic impact analysis for this final rule. The analysis is available in the RIA, which is in the public docket.

I. National Technology Transfer and Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act of 1995 (NTTAA), Public Law 104–113 (15 U.S.C. 272 note) directs the 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 the EPA to provide Congress, through OMB, explanations when the agency decides not to use available and applicable VCS.

This final rulemaking involves technical standards. Three VCS were identified as applicable for the purpose of these rules. The VCS ASTM D6522–00 (2005), *Standard Test Method for the Determination of Nitrogen Oxides, Carbon Monoxide, and Oxygen Concentrations in Emissions From Natural Gas-Fired Reciprocating Engines, Combustion Turbines, Boilers and Process Heaters Using Portable Analyzers,* is an acceptable alternative to EPA Methods 3A and 10 for identifying nitrogen oxides, carbon monoxide, and oxygen concentrations when the fuel is natural gas. The VCS ASTM D6420–99 (2004), *Test Method for Determination of Gaseous Organic Compounds by Direct Interface Gas Chromatography/Mass Spectrometry,* is an acceptable alternative to EPA Method 18. The VCS ANSI/ASME PTC 19.10–1981 (Part 10, Instruments and Apparatus), *Flue and Exhaust Gas Analyses* is an acceptable alternative to EPA Methods 3B and 16A manual portion only, not the instrumental portion.

No potential VCS were identified for EPA Methods 1A, 2A, 2D, 21, and 22.

During the search, if the title or abstract (if provided) of the VCS described technical sampling and analytical procedures that were similar to the EPA's reference method, the EPA ordered a copy of the standard and reviewed it as a potential equivalent method. All potential standards were reviewed to determine the practicality of the VCS for this action. This review requires significant method validation data that meet the requirements of EPA Method 301 for accepting alternative methods or scientific, engineering and policy equivalence to procedures in the EPA reference methods. The EPA may reconsider determinations of impracticality when additional information is available for particular VCS.

The search identified 18 other VCS that were potentially applicable for these rules in lieu of the EPA reference methods. After reviewing the available standards, the EPA determined that 18 candidate VCS (ASTM D3154–00 (2006), ASTM D3464–96 (2007), ASTM D3796–90 (2004), ISO 10780:1994, ASME B133.9–1994 (2001), ANSI/ASME PTC 19.10–1981 Part 10, ASTM D5835–95 (2007), ISO 10396:1993, ISO 12039:2001, ASTM D6522–00 (2005), CAN/CSA Z223.2–M86 (1999), CAN/CSA Z223.21–M1978, ASTM D3162–94 (2005), ASTM D4323–84 (2009), ASTM D6060–96 (2001), ISO 14965:2000(E), EN 12619 (1999), ASTM D4855–97 (2002)) identified for measuring emissions of pollutants or their surrogates subject to emission standards in the rules would not be practical due to lack of equivalency, documentation, validation data and other important technical and policy considerations. Refer to the memorandum in the docket for further details on the EPA's review of these VCS.

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.

The EPA has determined that this final rule will not have disproportionately high and adverse human health or environmental effects on minority or low-income populations because it increases the level of environmental protection for all affected populations without having any disproportionately high and adverse

human health or environmental effects on any population, including any minority, low-income, or indigenous populations.

To examine the potential for any environmental justice issues that might be associated with each source category, we evaluated the percentages of various social, demographic, and economic groups within the at-risk population living near the facilities where these source categories are located and compared them to national averages. The development of demographic analyses to inform the consideration of environmental justice issues in the EPA rulemakings is an evolving science.

The EPA conducted a demographic analysis, focusing on populations within 50 km of any facility in each of the source categories that are estimated to have HAP exposures which result in cancer risks of 1-in-1 million or greater or non-cancer hazard indices of 1 or greater based on estimates of current HAP emissions. The results of this analysis are documented in the technical report: *Risk and Technology Review—Analysis of Socio-Economic Factors for Populations Living Near Oil & Natural Gas Production Facilities,* located in the docket for this rulemaking.

As described in the preamble, our risk assessments demonstrate that the regulations for the oil and natural gas production and natural gas transmission and storage source categories, are associated with an acceptable level of risk and that the proposed additional requirements will provide an ample margin of safety to protect public health. Our analyses also show that, for these source categories, there is no potential for an adverse environmental effect or human health multi-pathway effects, and that acute and chronic non-cancer health impacts are unlikely. The EPA has determined that, although there may be an existing disparity in HAP risks from these sources between some demographic groups, no demographic group is exposed to an unacceptable level of risk.

To promote meaningful involvement, the EPA conducted three public hearings on the proposal. The hearings were held in Pittsburgh, Pennsylvania, on September 27, 2011, Denver, Colorado, on September 28, 2011, and Arlington, Texas, on September 29, 2011. A total of 261 people spoke at the three hearings and 735 people attended the hearings. The attendees at the hearings included private citizens, community-based and environmental organizations, industry representatives, associations representing industry and local and state government officials.

K. Congressional Review Act

The Congressional Review Act, 5 U.S.C. 801, *et seq.,* as added by the Small Business Regulatory Enforcement Fairness Act of 1996, generally provides that before a rule may take effect, the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of the Congress and to the Comptroller General of the United States. The EPA will submit a report containing this final rule and other required information to the United States Senate, the United States House of Representatives, and the Comptroller General of the United States prior to publication of the final rule in the **Federal Register**. A major rule cannot take effect until 60 days after it is published in the **Federal Register**. This action is a ''major rule'' as defined by 5 U.S.C. 804(2). The final rules will be effective on October 15, 2012.

List of Subjects

40 CFR Part 60

Environmental protection, Air pollution control, Incorporation by reference, Reporting and recordkeeping requirements, Volatile organic compounds.

40 CFR Part 63

Environmental protection, Administrative practice and procedures, Air pollution control, Hazardous substances, Incorporation by reference, Reporting and recordkeeping requirements, Volatile organic compounds.

Dated: April 17, 2012.

Lisa P. Jackson,

Administrator.

For the reasons set out in the preamble, title 40, chapter I of the Code of Federal Regulations is 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.*

■ 2. Section 60.17 is amended by:
■ a. Revising paragraph (a) introductory text, (a)(7), (a)(86), (a)(91), and (a)(92);
■ b. Adding paragraphs (a)(95), (a)(96), (a)(97), and (a)(98); and
■ c. Revising paragraph (h) introductory text and (h)(4) to read as follows:

§ 60.17 Incorporations by reference.

* * * * *

(a) The following materials are available for purchase from at least one of the following addresses: American Society for Testing and Materials (ASTM), 100 Barr Harbor Drive, Post Office Box C700, West Conshohocken, PA 19428–2959, Telephone (610) 832–9585, and are also available at the following Web site: *http://www.astm.org;* or ProQuest, 789 East Eisenhower Parkway, Ann Arbor, MI 48106–1346, Telephone (734) 761–4700, and are also available at the following Web site: *http://www.proquest.com.*

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(7) ASTM D86–96, Standard Test Method for Distillation of Petroleum Products (Approved April 10, 1996), IBR approved for §§ 60.562–2(d), 60.593(d), 60.593a(d), 60.633(h) and 60.5401(f).

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(86) ASTM D6522–00 (Reapproved 2005), Standard Test Method for Determination of Nitrogen Oxides, Carbon Monoxide, and Oxygen Concentrations in Emissions from Natural Gas-Fired Reciprocating Engines, Combustion Turbines, Boilers, and Process Heaters Using Portable Analyzers (Approved October 1, 2005), IBR approved for table 2 of subpart JJJJ of this part, and §§ 60.5413(b) and (d).

* * * * *

(91) ASTM E169–93, Standard Practices for General Techniques of Ultraviolet-Visible Quantitative Analysis (Approved May 15, 1993), IBR approved for §§ 60.485a(d), 60.593(b), 60.593a(b), 60.632(f) and 60.5400(f).

(92) ASTM E260–96, Standard Practice for Packed Column Gas Chromatography (Approved April 10, 1996), IBR approved for §§ 60.485a(d), 60.593(b), 60.593a(b), 60.632(f), 60.5400(f) and 60.5406(b).

* * * * *

(95) ASTM D3588–98 (Reapproved 2003) Standard Practice for Calculating Heat Value, Compressibility Factor, and Relative Density of Gaseous Fuels (Approved May 10, 2003), IBR approved for § 60.5413(d).

(96) ASTM D4891–89 (Reapproved 2006) Standard Test Method for Heating Value of Gases in Natural Gas Range by Stoichiometric Combustion (Approved June 1, 2006), IBR approved for § 60.5413(d).

(97) ASTM D1945–03 (Reapproved 2010), Standard Test Method for Analysis of Natural Gas by Gas Chromatography (Approved January 1, 2010), IBR approved for § 60.5413(d).

(98) ASTM D5504–08, Standard Test Method for Determination of Sulfur Compounds in Natural Gas and Gaseous Fuels by Gas Chromatography and Chemiluminescence (Approved June 15, 2008), IBR approved for § 60.5413(d).

* * * * *

(h) The following material is available for purchase from the American Society of Mechanical Engineers (ASME), Three Park Avenue, New York, NY 10016–5990, Telephone (800) 843–2763, and are also available at the following Web site: *http://www.asme.org.*

* * * * *

(4) ANSI/ASME PTC 19.10–1981, Flue and Exhaust Gas Analyses [Part 10, Instruments and Apparatus] (Issued August 31, 1981), IBR approved for §§ 60.56c(b), 60.63(f), 60.106(e), 60.104a(d), (h), (i) and (j), 60.105a(d), (f) and (g), 60.106a(a), 60.107a(a), (c) and (d), tables 1 and 3 of subpart EEEE, tables 2 and 4 of subpart FFFF, table 2 of subpart JJJJ, §§ 60.4415(a), 60.2145(s) and (t), 60.2710(s), (t) and (w), 60.2730(q), 60.4900(b) and 60.5220(b), tables 1 and 2 to subpart LLLL, tables 2 and 3 to subpart MMMM, §§ 60.5406(c) and 60.5413(b).

* * * * *

Subpart KKK—Standards of Performance for Equipment Leaks of VOC From Onshore Natural Gas Processing Plants for Which Construction, Reconstruction, or Modification Commenced After January 20, 1984, and on or Before August 23, 2011

■ 3. The heading for Subpart KKK is revised to read as set forth above.

■ 4. Section 60.630 is amended by revising paragraph (b) to read as follows:

§ 60.630 Applicability and designation of affected facility.

* * * * *

(b) Any affected facility under paragraph (a) of this section that commences construction, reconstruction, or modification after January 20, 1984, and on or before August 23, 2011, is subject to the requirements of this subpart.

* * * * *

Subpart LLL—Standards of Performance for SO_2 Emissions From Onshore Natural Gas Processing for Which Construction, Reconstruction, or Modification Commenced After January 20, 1984, and on or Before August 23, 2011

■ 5. The heading for Subpart LLL is revised to read as set forth above.

■ 6. Section 60.640 is amended by revising paragraph (d) to read as follows:

§ 60.640 Applicability and designation of affected facilities.

* * * * *

(d) The provisions of this subpart apply to each affected facility identified in paragraph (a) of this section which commences construction or modification after January 20, 1984, and on or before August 23, 2011.

* * * * *

■ 7. Add subpart OOOO, consisting of 60.5360 through 60.5430, to part 60 to read as follows:

Subpart OOOO—Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution

Sec.

60.5360 What is the purpose of this subpart?
60.5365 Am I subject to this subpart?
60.5370 When must I comply with this subpart?
60.5375 What standards apply to gas well affected facilities?
60.5380 What standards apply to centrifugal compressor affected facilities?
60.5385 What standards apply to reciprocating compressor affected facilities?
60.5390 What standards apply to pneumatic controller affected facilities?
60.5395 What standards apply to storage vessel affected facilities?
60.5400 What equipment leak standards apply to affected facilities at an onshore natural gas processing plant?
60.5401 What are the exceptions to the equipment leak standards for affected facilities at onshore natural gas processing plants?
60.5402 What are the alternative emission limitations for equipment leaks from onshore natural gas processing plants?
60.5405 What standards apply to sweetening units at onshore natural gas processing plants?
60.5406 What test methods and procedures must I use for my sweetening units affected facilities at onshore natural gas processing plants?
60.5407 What are the requirements for monitoring of emissions and operations from my sweetening unit affected facilities at onshore natural gas processing plants?
60.5408 What is an optional procedure for measuring hydrogen sulfide in acid gas—Tutwiler Procedure?
60.5410 How do I demonstrate initial compliance with the standards for my gas well affected facility, my centrifugal compressor affected facility, my reciprocating compressor affected facility, my pneumatic controller affected facility, my storage vessel affected facility, and my equipment leaks and sweetening unit affected facilities at onshore natural gas processing plants?
60.5411 What additional requirements must I meet to determine initial compliance for my closed vent systems routing emissions from storage vessels or centrifugal compressor wet seal fluid degassing systems?
60.5412 What additional requirements must I meet for determining initial compliance with control devices used to comply with the emission standards for my storage vessel or centrifugal compressor affected facility?
60.5413 What are the performance testing procedures for control devices used to demonstrate compliance at my storage vessel or centrifugal compressor affected facility?
60.5415 How do I demonstrate continuous compliance with the standards for my gas well affected facility, my centrifugal compressor affected facility, my stationary reciprocating compressor affected facility, my pneumatic controller affected facility, my storage vessel affected facility, and my affected facilities at onshore natural gas processing plants?
60.5416 What are the initial and continuous cover and closed vent system inspection and monitoring requirements for my storage vessel or centrifugal compressor affected facility?
60.5417 What are the continuous control device monitoring requirements for my storage vessel or centrifugal compressor affected facility?
60.5420 What are my notification, reporting, and recordkeeping requirements?
60.5421 What are my additional recordkeeping requirements for my affected facility subject to VOC requirements for onshore natural gas processing plants?
60.5422 What are my additional reporting requirements for my affected facility subject to VOC requirements for onshore natural gas processing plants?
60.5423 What additional recordkeeping and reporting requirements apply to my sweetening unit affected facilities at onshore natural gas processing plants?
60.5425 What parts of the General Provisions apply to me?
60.5430 What definitions apply to this subpart?
Table 1 to Subpart OOOO of Part 60—Required Minimum Initial SO_2 Emission Reduction Efficiency (Z_i)
Table 2 to Subpart OOOO of Part 60—Required Minimum SO_2 Emission Reduction Efficiency (Z_c)
Table 3 to Subpart OOOO of Part 60—Applicability of General Provisions to Subpart OOOO

Subpart OOOO—Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution

§ 60.5360 What is the purpose of this subpart?

This subpart establishes emission standards and compliance schedules for the control of volatile organic compounds (VOC) and sulfur dioxide (SO_2) emissions from affected facilities that commence construction, modification or reconstruction after August 23, 2011.

§ 60.5365 Am I subject to this subpart?

You are subject to the applicable provisions of this subpart if you are the owner or operator of one or more of the onshore affected facilities listed in paragraphs (a) through (g) of this section for which you commence construction, modification or reconstruction after August 23, 2011.

(a) Each gas well affected facility, which is a single natural gas well.

(b) Each centrifugal compressor affected facility, which is a single centrifugal compressor using wet seals that is located between the wellhead and the point of custody transfer to the natural gas transmission and storage segment. A centrifugal compressor located at a well site, or an adjacent well site and servicing more than one well site, is not an affected facility under this subpart.

(c) Each reciprocating compressor affected facility, which is a single reciprocating compressor located between the wellhead and the point of custody transfer to the natural gas transmission and storage segment. A reciprocating compressor located at a well site, or an adjacent well site and servicing more than one well site, is not an affected facility under this subpart.

(d)(1) For the oil production segment (between the wellhead and the point of custody transfer to an oil pipeline), each pneumatic controller affected facility, which is a single continuous bleed natural gas-driven pneumatic controller operating at a natural gas bleed rate greater than 6 scfh.

(2) For the natural gas production segment (between the wellhead and the point of custody transfer to the natural gas transmission and storage segment and not including natural gas processing plants), each pneumatic controller affected facility, which is a single continuous bleed natural gas-driven pneumatic controller operating at a natural gas bleed rate greater than 6 scfh.

(3) For natural gas processing plants, each pneumatic controller affected facility, which is a single continuous bleed natural gas-driven pneumatic controller.

(e) Each storage vessel affected facility, which is a single storage vessel, located in the oil and natural gas production segment, natural gas processing segment or natural gas transmission and storage segment.

(f) The group of all equipment, except compressors, within a process unit is an affected facility.

(1) Addition or replacement of equipment for the purpose of process improvement that is accomplished without a capital expenditure shall not by itself be considered a modification under this subpart.

(2) Equipment associated with a compressor station, dehydration unit, sweetening unit, underground storage vessel, field gas gathering system, or liquefied natural gas unit is covered by §§ 60.5400, 60.5401, 60.5402, 60.5421, and 60.5422 of this subpart if it is located at an onshore natural gas processing plant. Equipment not located at the onshore natural gas processing plant site is exempt from the provisions of §§ 60.5400, 60.5401, 60.5402, 60.5421, and 60.5422 of this subpart.

(3) The equipment within a process unit of an affected facility located at onshore natural gas processing plants and described in paragraph (f) of this section are exempt from this subpart if they are subject to and controlled according to subparts VVa, GGG or GGGa of this part.

(g) Sweetening units located at onshore natural gas processing plants that process natural gas produced from either onshore or offshore wells.

(1) Each sweetening unit that processes natural gas is an affected facility; and

(2) Each sweetening unit that processes natural gas followed by a sulfur recovery unit is an affected facility.

(3) Facilities that have a design capacity less than 2 long tons per day (LT/D) of hydrogen sulfide (H_2S) in the acid gas (expressed as sulfur) are required to comply with recordkeeping and reporting requirements specified in § 60.5423(c) but are not required to comply with §§ 60.5405 through 60.5407 and §§ 60.5410(g) and 60.5415(g) of this subpart.

(4) Sweetening facilities producing acid gas that is completely reinjected into oil-or-gas-bearing geologic strata or that is otherwise not released to the atmosphere are not subject to §§ 60.5405 through 60.5407, 60.5410(g), 60.5415(g), and 60.5423 of this subpart.

(h) The following provisions apply to gas well facilities that are hydraulically refractured.

(1) A gas well facility that conducts a well completion operation following hydraulic refracturing is not an affected facility, provided that the requirements of § 60.5375 are met. For purposes of this provision, the dates specified in § 60.5375(a) do not apply, and such facilities, as of October 15, 2012, must meet the requirements of § 60.5375(a)(1) through (4).

(2) A well completion operation following hydraulic refracturing at a gas well facility not conducted pursuant to § 60.5375 is a modification to the gas well affected facility.

(3) Refracturing of a gas well facility does not affect the modification status of other equipment, process units, storage vessels, compressors, or pneumatic controllers located at the well site.

(4) Sources initially constructed after August 23, 2011, are considered affected sources regardless of this provision.

§ 60.5370 When must I comply with this subpart?

(a) You must be in compliance with the standards of this subpart no later than October 15, 2012 or upon startup, whichever is later.

(b) The provisions for exemption from compliance during periods of startup, shutdown and malfunctions provided for in 40 CFR 60.8(c) do not apply to this subpart.

(c) You are exempt from the obligation to obtain a permit under 40 CFR part 70 or 40 CFR part 71, provided you are not otherwise required by law to obtain a permit under 40 CFR 70.3(a) or 40 CFR 71.3(a). Notwithstanding the previous sentence, you must continue to comply with the provisions of this subpart.

§ 60.5375 What standards apply to gas well affected facilities?

If you are the owner or operator of a gas well affected facility, you must comply with paragraphs (a) through (f) of this section.

(a) Except as provided in paragraph (f) of this section, for each well completion operation with hydraulic fracturing begun prior to January 1, 2015, you must comply with the requirements of paragraphs (a)(3) and (4) of this section unless a more stringent state or local emission control requirement is applicable; optionally, you may comply with the requirements of paragraphs (a)(1) through (4) of this section. For each new well completion operation with hydraulic fracturing begun on or after January 1, 2015, you must comply with the requirements in paragraphs (a)(1) through (4) of this section.

(1) For the duration of flowback, route the recovered liquids into one or more storage vessels or re-inject the recovered liquids into the well or another well, and route the recovered gas into a gas flow line or collection system, re-inject the recovered gas into the well or another well, use the recovered gas as an on-site fuel source, or use the recovered gas for another useful purpose that a purchased fuel or raw material would serve, with no direct release to the atmosphere. If this is infeasible, follow the requirements in paragraph (a)(3) of this section.

(2) All salable quality gas must be routed to the gas flow line as soon as

practicable. In cases where flowback emissions cannot be directed to the flow line, you must follow the requirements in paragraph (a)(3) of this section.

(3) You must capture and direct flowback emissions to a completion combustion device, except in conditions that may result in a fire hazard or explosion, or where high heat emissions from a completion combustion device may negatively impact tundra, permafrost or waterways. Completion combustion devices must be equipped with a reliable continuous ignition source over the duration of flowback.

(4) You have a general duty to safely maximize resource recovery and minimize releases to the atmosphere during flowback and subsequent recovery.

(b) You must maintain a log for each well completion operation at each gas well affected facility. The log must be completed on a daily basis for the duration of the well completion operation and must contain the records specified in § 60.5420(c)(1)(iii).

(c) You must demonstrate initial compliance with the standards that apply to gas well affected facilities as required by § 60.5410.

(d) You must demonstrate continuous compliance with the standards that apply to gas well affected facilities as required by § 60.5415.

(e) You must perform the required notification, recordkeeping and reporting as required by § 60.5420.

(f)(1) For each gas well affected facility specified in paragraphs (f)(1)(i) and (ii) of this section, you must comply with the requirements of paragraphs (f)(2) and (3) of this section.

(i) Each well completion operation with hydraulic fracturing at a gas well affected facility meeting the criteria for a wildcat or delineation well.

(ii) Each well completion operation with hydraulic fracturing at a gas well affected facility meeting the criteria for a non-wildcat low pressure gas well or non-delineation low pressure gas well.

(2) You must capture and direct flowback emissions to a completion combustion device, except in conditions that may result in a fire hazard or explosion, or where high heat emissions from a completion combustion device may negatively impact tundra, permafrost or waterways. Completion combustion devices must be equipped with a reliable continuous ignition source over the duration of flowback. You must also comply with paragraphs (a)(4) and (b) through (e) of this section.

(3) You must maintain records specified in § 60.5420(c)(1)(iii) for wildcat, delineation and low pressure gas wells.

§ 60.5380 What standards apply to centrifugal compressor affected facilities?

You must comply with the standards in paragraphs (a) through (d) of this section for each centrifugal compressor affected facility.

(a)(1) You must reduce VOC emissions from each centrifugal compressor wet seal fluid degassing system by 95.0 percent or greater.

(2) If you use a control device to reduce emissions, you must equip the wet seal fluid degassing system with a cover that meets the requirements of § 60.5411(b) and is connected through a closed vent system that meets the requirements of § 60.5411(a) to a control device that meets the conditions specified in § 60.5412.

(b) You must demonstrate initial compliance with the standards that apply to centrifugal compressor affected facilities as required by § 60.5410.

(c) You must demonstrate continuous compliance with the standards that apply to centrifugal compressor affected facilities as required by § 60.5415.

(d) You must perform the required notification, recordkeeping, and reporting as required by § 60.5420.

§ 60.5385 What standards apply to reciprocating compressor affected facilities?

You must comply with the standards in paragraphs (a) through (d) of this section for each reciprocating compressor affected facility.

(a) You must replace the reciprocating compressor rod packing according to either paragraph (a)(1) or (2) of this section.

(1) Before the compressor has operated for 26,000 hours. The number of hours of operation must be continuously monitored beginning upon initial startup of your reciprocating compressor affected facility, or October 15, 2012, or the date of the most recent reciprocating compressor rod packing replacement, whichever is later.

(2) Prior to 36 months from the date of the most recent rod packing replacement, or 36 months from the date of startup for a new reciprocating compressor for which the rod packing has not yet been replaced.

(b) You must demonstrate initial compliance with standards that apply to reciprocating compressor affected facilities as required by § 60.5410.

(c) You must demonstrate continuous compliance with standards that apply to reciprocating compressor affected facilities as required by § 60.5415.

(d) You must perform the required notification, recordkeeping, and reporting as required by § 60.5420.

§ 60.5390 What standards apply to pneumatic controller affected facilities?

For each pneumatic controller affected facility you must comply with the VOC standards, based on natural gas as a surrogate for VOC, in either paragraph (b) or (c) of this section, as applicable. Pneumatic controllers meeting the conditions in paragraph (a) of this section are exempt from this requirement.

(a) The requirements of paragraph (b) or (c) of this section are not required if you determine that the use of a pneumatic controller affected facility with a bleed rate greater than 6 standard cubic feet per hour is required based on functional needs, including but not limited to response time, safety and positive actuation.

(b)(1) Each pneumatic controller affected facility at a natural gas processing plant must have a bleed rate of zero.

(2) Each pneumatic controller affected facility at a natural gas processing plant must be tagged with the month and year of installation, reconstruction or modification, and identification information that allows traceability to the records for that pneumatic controller as required in § 60.5420(c)(4)(iv).

(c)(1) Each pneumatic controller affected facility constructed, modified or reconstructed on or after October 15, 2013 at a location between the wellhead and a natural gas processing plant must have a bleed rate less than or equal to 6 standard cubic feet per hour.

(2) Each pneumatic controller affected facility at a location between the wellhead and a natural gas processing plant must be tagged with the month and year of installation, reconstruction or modification, and identification information that allows traceability to the records for that controller as required in § 60.5420(c)(4)(iii).

(d) You must demonstrate initial compliance with standards that apply to pneumatic controller affected facilities as required by § 60.5410.

(e) You must demonstrate continuous compliance with standards that apply to pneumatic controller affected facilities as required by § 60.5415.

(f) You must perform the required notification, recordkeeping, and reporting as required by § 60.5420, except that you are not required to submit the notifications specified in § 60.5420(a).

§ 60.5395 What standards apply to storage vessel affected facilities?

Except as provided in paragraph (d) of this section, you must comply with the standards in this section no later than October 15, 2013 for each storage vessel

affected facility constructed, modified or reconstructed after August 23, 2011, with VOC emissions equal to or greater than 6 tpy, as determined in paragraph (a) of this section.

(a) *Emissions determination*—(1) *Well sites with no other wells in production.* For each storage vessel constructed, modified or reconstructed at a well site with no other wells in production, you must determine the VOC emission rate for each storage vessel affected facility using any generally accepted model or calculation methodology within 30 days after startup, and minimize emissions to the extent practicable during the 30-day period using good engineering practices. For each storage vessel affected facility emitting more than 6 tpy VOC, you must reduce VOC emissions by 95.0 percent or greater within 60 days after startup.

(2) *Well sites with one or more wells already in production.* For each storage vessel constructed, modified or reconstructed at a well site with one or more wells already in production, you must determine the VOC emission rate for each storage vessel affected facility using any generally accepted model or calculation methodology upon startup. For each storage vessel affected facility emitting more than 6 tpy VOC, you must reduce VOC emissions by 95.0 percent or greater upon startup.

(b) *Control requirements.* (1) If you use a control device (such as an enclosed combustion device or vapor recovery device) to reduce emissions, you must equip the storage vessel with a cover that meets the requirements of § 60.5411(b) and is connected through a closed vent system that meets the requirements of § 60.5411(a) to a control device that meets the conditions specified in § 60.5412.

(2) If you use a floating roof to reduce emissions, you must meet the requirements of § 60.112b(a)(1) or (2) and the relevant monitoring, inspection, recordkeeping, and reporting requirements in 40 CFR part 60, subpart Kb.

(c) *Compliance, notification, recordkeeping, and reporting.* (1) You must demonstrate initial compliance with standards that apply to storage vessel affected facilities as required by § 60.5410.

(2) You must demonstrate continuous compliance with standards that apply to storage vessel affected facilities as required by § 60.5415.

(3) You must perform the required notification, recordkeeping, and reporting as required by § 60.5420.

(d) *Exemptions.* This section does not apply to storage vessels subject to and controlled in accordance with the requirements for storage vessels in 40 CFR part 60, subpart Kb, or 40 CFR part 63, subparts G, CC, HH, WW, or HHH.

§ 60.5400 What equipment leak standards apply to affected facilities at an onshore natural gas processing plant?

This section applies to the group of all equipment, except compressors, within a process unit.

(a) You must comply with the requirements of §§ 60.482–1a(a), (b), and (d), 60.482–2a, and 60.482–4a through 60.482–11a, except as provided in § 60.5401.

(b) You may elect to comply with the requirements of §§ 60.483–1a and 60.483–2a, as an alternative.

(c) You may apply to the Administrator for permission to use an alternative means of emission limitation that achieves a reduction in emissions of VOC at least equivalent to that achieved by the controls required in this subpart according to the requirements of § 60.5402 of this subpart.

(d) You must comply with the provisions of § 60.485a of this part except as provided in paragraph (f) of this section.

(e) You must comply with the provisions of §§ 60.486a and 60.487a of this part except as provided in §§ 60.5401, 60.5421, and 60.5422 of this part.

(f) You must use the following provision instead of § 60.485a(d)(1): Each piece of equipment is presumed to be in VOC service or in wet gas service unless an owner or operator demonstrates that the piece of equipment is not in VOC service or in wet gas service. For a piece of equipment to be considered not in VOC service, it must be determined that the VOC content can be reasonably expected never to exceed 10.0 percent by weight. For a piece of equipment to be considered in wet gas service, it must be determined that it contains or contacts the field gas before the extraction step in the process. For purposes of determining the percent VOC content of the process fluid that is contained in or contacts a piece of equipment, procedures that conform to the methods described in ASTM E169–93, E168–92, or E260–96 (incorporated by reference as specified in § 60.17) must be used.

§ 60.5401 What are the exceptions to the equipment leak standards for affected facilities at onshore natural gas processing plants?

(a) You may comply with the following exceptions to the provisions of § 60.5400(a) and (b).

(b)(1) Each pressure relief device in gas/vapor service may be monitored quarterly and within 5 days after each pressure release to detect leaks by the methods specified in § 60.485a(b) except as provided in § 60.5400(c) and in paragraph (b)(4) of this section, and § 60.482–4a(a) through (c) of subpart VVa.

(2) If an instrument reading of 500 ppm or greater is measured, a leak is detected.

(3)(i) When a leak is detected, it must be repaired as soon as practicable, but no later than 15 calendar days after it is detected, except as provided in § 60.482–9a.

(ii) A first attempt at repair must be made no later than 5 calendar days after each leak is detected.

(4)(i) Any pressure relief device that is located in a nonfractionating plant that is monitored only by non-plant personnel may be monitored after a pressure release the next time the monitoring personnel are on-site, instead of within 5 days as specified in paragraph (b)(1) of this section and § 60.482–4a(b)(1) of subpart VVa.

(ii) No pressure relief device described in paragraph (b)(4)(i) of this section must be allowed to operate for more than 30 days after a pressure release without monitoring.

(c) Sampling connection systems are exempt from the requirements of § 60.482–5a.

(d) Pumps in light liquid service, valves in gas/vapor and light liquid service, and pressure relief devices in gas/vapor service that are located at a nonfractionating plant that does not have the design capacity to process 283,200 standard cubic meters per day (scmd) (10 million standard cubic feet per day) or more of field gas are exempt from the routine monitoring requirements of §§ 60.482–2a(a)(1) and 60.482–7a(a), and paragraph (b)(1) of this section.

(e) Pumps in light liquid service, valves in gas/vapor and light liquid service, and pressure relief devices in gas/vapor service within a process unit that is located in the Alaskan North Slope are exempt from the routine monitoring requirements of §§ 60.482–2a(a)(1), 60.482–7a(a), and paragraph (b)(1) of this section.

(f) An owner or operator may use the following provisions instead of § 60.485a(e):

(1) Equipment is in heavy liquid service if the weight percent evaporated is 10 percent or less at 150 °C (302 °F) as determined by ASTM Method D86–96 (incorporated by reference as specified in § 60.17).

(2) Equipment is in light liquid service if the weight percent evaporated is greater than 10 percent at 150 °C (302 °F) as determined by ASTM Method

D86–96 (incorporated by reference as specified in § 60.17).

(g) An owner or operator may use the following provisions instead of § 60.485a(b)(2): A calibration drift assessment shall be performed, at a minimum, at the end of each monitoring day. Check the instrument using the same calibration gas(es) that were used to calibrate the instrument before use. Follow the procedures specified in Method 21 of appendix A–7 of this part, Section 10.1, except do not adjust the meter readout to correspond to the calibration gas value. Record the instrument reading for each scale used as specified in § 60.486a(e)(8). Divide these readings by the initial calibration values for each scale and multiply by 100 to express the calibration drift as a percentage. If any calibration drift assessment shows a negative drift of more than 10 percent from the initial calibration value, then all equipment monitored since the last calibration with instrument readings below the appropriate leak definition and above the leak definition multiplied by (100 minus the percent of negative drift/ divided by 100) must be re-monitored. If any calibration drift assessment shows a positive drift of more than 10 percent from the initial calibration value, then, at the owner/operator's discretion, all equipment since the last calibration with instrument readings above the appropriate leak definition and below the leak definition multiplied by (100 plus the percent of positive drift/ divided by 100) may be re-monitored.

§ 60.5402 What are the alternative emission limitations for equipment leaks from onshore natural gas processing plants?

(a) If, in the Administrator's judgment, an alternative means of emission limitation will achieve a reduction in VOC emissions at least equivalent to the reduction in VOC emissions achieved under any design, equipment, work practice or operational standard, the Administrator will publish, in the **Federal Register**, a notice permitting the use of that alternative means for the purpose of compliance with that standard. The notice may condition permission on requirements related to the operation and maintenance of the alternative means.

(b) Any notice under paragraph (a) of this section must be published only after notice and an opportunity for a public hearing.

(c) The Administrator will consider applications under this section from either owners or operators of affected facilities, or manufacturers of control equipment.

(d) The Administrator will treat applications under this section according to the following criteria, except in cases where the Administrator concludes that other criteria are appropriate:

(1) The applicant must collect, verify and submit test data, covering a period of at least 12 months, necessary to support the finding in paragraph (a) of this section.

(2) If the applicant is an owner or operator of an affected facility, the applicant must commit in writing to operate and maintain the alternative means so as to achieve a reduction in VOC emissions at least equivalent to the reduction in VOC emissions achieved under the design, equipment, work practice or operational standard.

§ 60.5405 What standards apply to sweetening units at onshore natural gas processing plants?

(a) During the initial performance test required by § 60.8(b), you must achieve at a minimum, an SO_2 emission reduction efficiency (Z_i) to be determined from Table 1 of this subpart based on the sulfur feed rate (X) and the sulfur content of the acid gas (Y) of the affected facility.

(b) After demonstrating compliance with the provisions of paragraph (a) of this section, you must achieve at a minimum, an SO_2 emission reduction efficiency (Z_c) to be determined from Table 2 of this subpart based on the sulfur feed rate (X) and the sulfur content of the acid gas (Y) of the affected facility.

60.5406 What test methods and procedures must I use for my sweetening units affected facilities at onshore natural gas processing plants?

(a) In conducting the performance tests required in § 60.8, you must use the test methods in appendix A of this part or other methods and procedures as specified in this section, except as provided in paragraph § 60.8(b).

(b) During a performance test required by § 60.8, you must determine the minimum required reduction efficiencies (Z) of SO_2 emissions as required in § 60.5405(a) and (b) as follows:

(1) The average sulfur feed rate (X) must be computed as follows:

$$X = KQ_aY$$

Where:

X = average sulfur feed rate, Mg/D (LT/D).

Q_a = average volumetric flow rate of acid gas from sweetening unit, dscm/day (dscf/day).

Y = average H_2S concentration in acid gas feed from sweetening unit, percent by volume, expressed as a decimal.

K = (32 kg S/kg-mole)/((24.04 dscm/kg-mole)(1000 kg S/Mg)).

= 1.331×10^{-3}Mg/dscm, for metric units.

= (32 lb S/lb-mole)/((385.36 dscf/lb-mole)(2240 lb S/long ton)).

= 3.707×10^{-5} long ton/dscf, for English units.

(2) You must use the continuous readings from the process flowmeter to determine the average volumetric flow rate (Q_a) in dscm/day (dscf/day) of the acid gas from the sweetening unit for each run.

(3) You must use the Tutwiler procedure in § 60.5408 or a chromatographic procedure following ASTM E260–96 (incorporated by reference as specified in § 60.17) to determine the H_2S concentration in the acid gas feed from the sweetening unit (Y). At least one sample per hour (at equally spaced intervals) must be taken during each 4-hour run. The arithmetic mean of all samples must be the average H_2S concentration (Y) on a dry basis for the run. By multiplying the result from the Tutwiler procedure by 1.62×10^{-3}, the units gr/100 scf are converted to volume percent.

(4) Using the information from paragraphs (b)(1) and (b)(3) of this section, Tables 1 and 2 of this subpart must be used to determine the required initial (Z_i) and continuous (Z_c) reduction efficiencies of SO_2 emissions.

(c) You must determine compliance with the SO_2 standards in § 60.5405(a) or (b) as follows:

(1) You must compute the emission reduction efficiency (R) achieved by the sulfur recovery technology for each run using the following equation:

$$R = (100S)\frac{\square}{S + E}$$

(2) You must use the level indicators or manual soundings to measure the liquid sulfur accumulation rate in the product storage vessels. You must use readings taken at the beginning and end of each run, the tank geometry, sulfur density at the storage temperature, and sample duration to determine the sulfur production rate (S) in kg/hr (lb/hr) for each run.

(3) You must compute the emission rate of sulfur for each run as follows:

$$E = \frac{C_e Q_{sd}}{K_1}$$

Where:

E = emission rate of sulfur per run, kg/hr.

C_e = concentration of sulfur equivalent (SO^{2+} reduced sulfur), g/dscm (lb/dscf).

Q_{sd} = volumetric flow rate of effluent gas, dscm/hr (dscf/hr).

K_1 = conversion factor, 1000 g/kg (7000 gr/lb).

(4) The concentration (C_e) of sulfur equivalent must be the sum of the SO_2 and TRS concentrations, after being converted to sulfur equivalents. For each run and each of the test methods specified in this paragraph (c) of this section, you must use a sampling time of at least 4 hours. You must use Method 1 of appendix A to part 60 of this chapter to select the sampling site. The sampling point in the duct must be at the centroid of the cross-section if the area is less than 5 m^2 (54 ft^2) or at a point no closer to the walls than 1 m (39 in) if the cross-sectional area is 5 m^2 or more, and the centroid is more than 1 m (39 in.) from the wall.

(i) You must use Method 6 of appendix A to part 60 of this chapter to determine the SO_2 concentration. You must take eight samples of 20 minutes each at 30-minute intervals. The arithmetic average must be the concentration for the run. The concentration must be multiplied by 0.5×10^{-3} to convert the results to sulfur equivalent.

(ii) You must use Method 15 of appendix A to part 60 of this chapter to determine the TRS concentration from reduction-type devices or where the oxygen content of the effluent gas is less than 1.0 percent by volume. The sampling rate must be at least 3 liters/min (0.1 ft^3/min) to insure minimum residence time in the sample line. You must take sixteen samples at 15-minute intervals. The arithmetic average of all the samples must be the concentration for the run. The concentration in ppm reduced sulfur as sulfur must be multiplied by 1.333×10^{-3} to convert the results to sulfur equivalent.

(iii) You must use Method 16A or Method 15 of appendix A to part 60 of this chapter or ANSI/ASME PTC 19.10–1981, Part 10 (manual portion only) (incorporated by reference as specified in § 60.17) to determine the reduced sulfur concentration from oxidation-type devices or where the oxygen content of the effluent gas is greater than 1.0 percent by volume. You must take eight samples of 20 minutes each at 30-minute intervals. The arithmetic average must be the concentration for the run. The concentration in ppm reduced sulfur as sulfur must be multiplied by 1.333×10^{-3} to convert the results to sulfur equivalent.

(iv) You must use Method 2 of appendix A to part 60 of this chapter to determine the volumetric flow rate of the effluent gas. A velocity traverse must be conducted at the beginning and end of each run. The arithmetic average of the two measurements must be used to calculate the volumetric flow rate (Q_{sd}) for the run. For the determination of the effluent gas molecular weight, a single integrated sample over the 4-hour period may be taken and analyzed or grab samples at 1-hour intervals may be taken, analyzed, and averaged. For the moisture content, you must take two samples of at least 0.10 dscm (3.5 dscf) and 10 minutes at the beginning of the 4-hour run and near the end of the time period. The arithmetic average of the two runs must be the moisture content for the run.

60.5407 What are the requirements for monitoring of emissions and operations from my sweetening unit affected facilities at onshore natural gas processing plants?

(a) If your sweetening unit affected facility is located at an onshore natural gas processing plant and is subject to the provisions of § 60.5405(a) or (b) you must install, calibrate, maintain, and operate monitoring devices or perform measurements to determine the following operations information on a daily basis:

(1) *The accumulation of sulfur product over each 24-hour period.* The monitoring method may incorporate the use of an instrument to measure and record the liquid sulfur production rate, or may be a procedure for measuring and recording the sulfur liquid levels in the storage vessels with a level indicator or by manual soundings, with subsequent calculation of the sulfur production rate based on the tank geometry, stored sulfur density, and elapsed time between readings. The method must be designed to be accurate within ±2 percent of the 24-hour sulfur accumulation.

(2) *The H_2S concentration in the acid gas from the sweetening unit for each 24-hour period.* At least one sample per 24-hour period must be collected and analyzed using the equation specified in § 60.5406(b)(1). The Administrator may require you to demonstrate that the H_2S concentration obtained from one or more samples over a 24-hour period is within ±20 percent of the average of 12 samples collected at equally spaced intervals during the 24-hour period. In instances where the H_2S concentration of a single sample is not within ±20 percent of the average of the 12 equally spaced samples, the Administrator may require a more frequent sampling schedule.

(3) *The average acid gas flow rate from the sweetening unit.* You must install and operate a monitoring device to continuously measure the flow rate of acid gas. The monitoring device reading must be recorded at least once per hour during each 24-hour period. The average acid gas flow rate must be computed from the individual readings.

(4) *The sulfur feed rate (X).* For each 24-hour period, you must compute X using the equation specified in § 60.5406(b)(1).

(5) *The required sulfur dioxide emission reduction efficiency for the 24-hour period.* You must use the sulfur feed rate and the H_2S concentration in the acid gas for the 24-hour period, as applicable, to determine the required reduction efficiency in accordance with the provisions of § 60.5405(b).

(b) Where compliance is achieved through the use of an oxidation control system or a reduction control system followed by a continually operated incineration device, you must install, calibrate, maintain, and operate monitoring devices and continuous emission monitors as follows:

(1) *A continuous monitoring system to measure the total sulfur emission rate (E) of SO_2 in the gases discharged to the atmosphere.* The SO_2 emission rate must be expressed in terms of equivalent sulfur mass flow rates (kg/hr (lb/hr)). The span of this monitoring system must be set so that the equivalent emission limit of § 60.5405(b) will be between 30 percent and 70 percent of the measurement range of the instrument system.

(2) Except as provided in paragraph (b)(3) of this section: A monitoring device to measure the temperature of the gas leaving the combustion zone of the incinerator, if compliance with § 60.5405(a) is achieved through the use of an oxidation control system or a reduction control system followed by a continually operated incineration device. The monitoring device must be certified by the manufacturer to be accurate to within ±1 percent of the temperature being measured.

(3) When performance tests are conducted under the provision of § 60.8 to demonstrate compliance with the standards under § 60.5405, the temperature of the gas leaving the incinerator combustion zone must be determined using the monitoring device. If the volumetric ratio of sulfur dioxide to sulfur dioxide plus total reduced sulfur (expressed as SO_2) in the gas leaving the incinerator is equal to or less than 0.98, then temperature monitoring may be used to demonstrate that sulfur dioxide emission monitoring is sufficient to determine total sulfur emissions. At all times during the operation of the facility, you must maintain the average temperature of the gas leaving the combustion zone of the incinerator at or above the appropriate level determined during the most recent

performance test to ensure the sulfur compound oxidation criteria are met. Operation at lower average temperatures may be considered by the Administrator to be unacceptable operation and maintenance of the affected facility. You may request that the minimum incinerator temperature be reestablished by conducting new performance tests under § 60.8.

(4) Upon promulgation of a performance specification of continuous monitoring systems for total reduced sulfur compounds at sulfur recovery plants, you may, as an alternative to paragraph (b)(2) of this section, install, calibrate, maintain, and operate a continuous emission monitoring system for total reduced sulfur compounds as required in paragraph (d) of this section in addition to a sulfur dioxide emission monitoring system. The sum of the equivalent sulfur mass emission rates from the two monitoring systems must be used to compute the total sulfur emission rate (E).

(c) Where compliance is achieved through the use of a reduction control system not followed by a continually operated incineration device, you must install, calibrate, maintain, and operate a continuous monitoring system to measure the emission rate of reduced sulfur compounds as SO_2 equivalent in the gases discharged to the atmosphere. The SO_2 equivalent compound emission rate must be expressed in terms of equivalent sulfur mass flow rates (kg/hr (lb/hr)). The span of this monitoring system must be set so that the equivalent emission limit of § 60.5405(b) will be between 30 and 70 percent of the measurement range of the system. This requirement becomes effective upon promulgation of a performance specification for continuous monitoring systems for total reduced sulfur compounds at sulfur recovery plants.

(d) For those sources required to comply with paragraph (b) or (c) of this section, you must calculate the average sulfur emission reduction efficiency achieved (R) for each 24-hour clock interval. The 24-hour interval may begin and end at any selected clock time, but must be consistent. You must compute the 24-hour average reduction efficiency (R) based on the 24-hour average sulfur production rate (S) and sulfur emission rate (E), using the equation in § 60.5406(c)(1).

(1) You must use data obtained from the sulfur production rate monitoring device specified in paragraph (a) of this section to determine S.

(2) You must use data obtained from the sulfur emission rate monitoring systems specified in paragraphs (b) or (c) of this section to calculate a 24-hour average for the sulfur emission rate (E). The monitoring system must provide at least one data point in each successive 15-minute interval. You must use at least two data points to calculate each 1-hour average. You must use a minimum of 18 1-hour averages to compute each 24-hour average.

(e) In lieu of complying with paragraphs (b) or (c) of this section, those sources with a design capacity of less than 152 Mg/D (150 LT/D) of H_2S expressed as sulfur may calculate the sulfur emission reduction efficiency achieved for each 24-hour period by:

$$R = \frac{K_2 S}{X}$$

Where:

R = The sulfur dioxide removal efficiency achieved during the 24-hour period, percent.

K_2 = Conversion factor, 0.02400 Mg/D per kg/hr (0.01071 LT/D per lb/hr).

S = The sulfur production rate during the 24-hour period, kg/hr (lb/hr).

X = The sulfur feed rate in the acid gas, Mg/D (LT/D).

(f) The monitoring devices required in paragraphs (b)(1), (b)(3) and (c) of this section must be calibrated at least annually according to the manufacturer's specifications, as required by § 60.13(b).

(g) The continuous emission monitoring systems required in paragraphs (b)(1), (b)(3), and (c) of this section must be subject to the emission monitoring requirements of § 60.13 of the General Provisions. For conducting the continuous emission monitoring system performance evaluation required by § 60.13(c), Performance Specification 2 of appendix B to part 60 of this chapter must apply, and Method 6 must be used for systems required by paragraph (b) of this section.

§ 60.5408 What is an optional procedure for measuring hydrogen sulfide in acid gas—Tutwiler Procedure?

The Tutwiler procedure may be found in the Gas Engineers Handbook, Fuel Gas Engineering practices, The Industrial Press, 93 Worth Street, New York, NY, 1966, First Edition, Second Printing, page 6/25 (Docket A–80–20–A, Entry II–I–67).

(a) When an instantaneous sample is desired and H_2S concentration is ten grains per 1000 cubic foot or more, a 100 ml Tutwiler burette is used. For concentrations less than ten grains, a 500 ml Tutwiler burette and more dilute solutions are used. In principle, this method consists of titrating hydrogen sulfide in a gas sample directly with a standard solution of iodine.

(b) *Apparatus.* (See Figure 1 of this subpart) A 100 or 500 ml capacity Tutwiler burette, with two-way glass stopcock at bottom and three-way stopcock at top which connect either with inlet tubulature or glass-stoppered cylinder, 10 ml capacity, graduated in 0.1 ml subdivision; rubber tubing connecting burette with leveling bottle.

(c) *Reagents.* (1) Iodine stock solution, 0.1N. Weight 12.7 g iodine, and 20 to 25 g cp potassium iodide for each liter of solution. Dissolve KI in as little water as necessary; dissolve iodine in concentrated KI solution, make up to proper volume, and store in glass-stoppered brown glass bottle.

(2) Standard iodine solution, 1 ml=0.001771 g I. Transfer 33.7 ml of above 0.1N stock solution into a 250 ml volumetric flask; add water to mark and mix well. Then, for 100 ml sample of gas, 1 ml of standard iodine solution is equivalent to 100 grains H_2S per cubic feet of gas.

(3) Starch solution. Rub into a thin paste about one teaspoonful of wheat starch with a little water; pour into about a pint of boiling water; stir; let cool and decant off clear solution. Make fresh solution every few days.

(d) *Procedure.* Fill leveling bulb with starch solution. Raise (L), open cock (G), open (F) to (A), and close (F) when solutions starts to run out of gas inlet. Close (G). Purge gas sampling line and connect with (A). Lower (L) and open (F) and (G). When liquid level is several ml past the 100 ml mark, close (G) and (F), and disconnect sampling tube. Open (G) and bring starch solution to 100 ml mark by raising (L); then close (G). Open (F) momentarily, to bring gas in burette to atmospheric pressure, and close (F). Open (G), bring liquid level down to 10 ml mark by lowering (L). Close (G), clamp rubber tubing near (E) and disconnect it from burette. Rinse graduated cylinder with a standard iodine solution (0.00171 g I per ml); fill cylinder and record reading. Introduce successive small amounts of iodine thru (F); shake well after each addition; continue until a faint permanent blue color is obtained. Record reading; subtract from previous reading, and call difference D.

(e) With every fresh stock of starch solution perform a blank test as follows: Introduce fresh starch solution into burette up to 100 ml mark. Close (F) and (G). Lower (L) and open (G). When liquid level reaches the 10 ml mark, close (G). With air in burette, titrate as during a test and up to same end point. Call ml of iodine used C. Then, Grains H_2S per 100 cubic foot of gas = 100(D–C)

(f) Greater sensitivity can be attained if a 500 ml capacity Tutwiler burette is used with a more dilute (0.001N) iodine solution. Concentrations less than 1.0 grains per 100 cubic foot can be determined in this way. Usually, the starch-iodine end point is much less distinct, and a blank determination of end point, with H_2S-free gas or air, is required.

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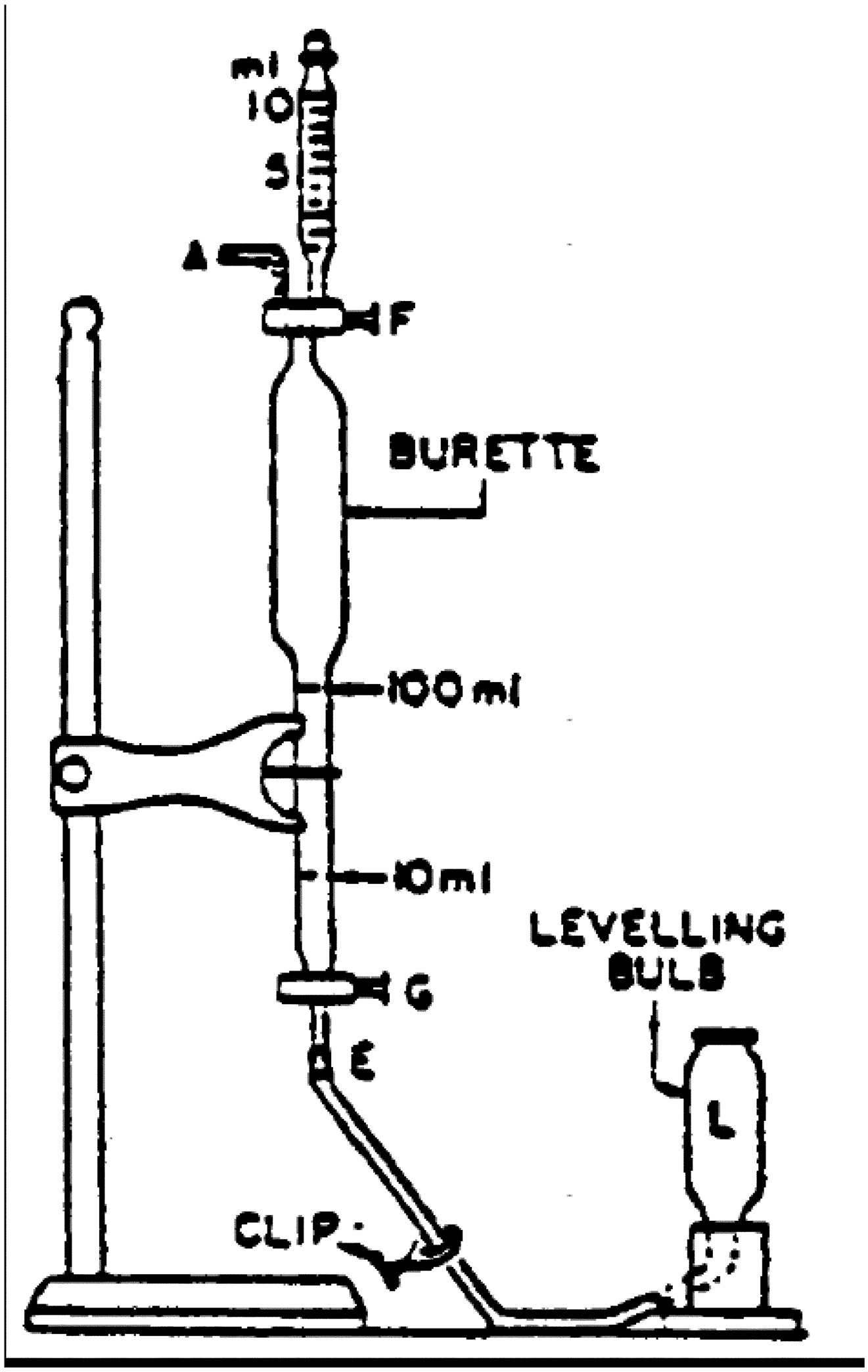

Figure 1. Tutwiler burette (lettered items mentioned in text).

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§ 60.5410 How do I demonstrate initial compliance with the standards for my gas well affected facility, my centrifugal compressor affected facility, my reciprocating compressor affected facility, my pneumatic controller affected facility, my storage vessel affected facility, and my equipment leaks and sweetening unit affected facilities at onshore natural gas processing plants?

You must determine initial compliance with the standards for each affected facility using the requirements in paragraphs (a) through (g) of this section. The initial compliance period begins on October 15, 2012 or upon initial startup, whichever is later, and ends no later than one year after the initial startup date for your affected facility or no later than one year after October 15, 2012. The initial compliance period may be less than one full year.

(a) To achieve initial compliance with the standards for each well completion operation conducted at your gas well affected facility you must comply with paragraphs (a)(1) through (a)(4) of this section.

(1) You must submit the notification required in § 60.5420(a)(2).

(2) You must submit the initial annual report for your well affected facility as required in § 60.5420(b).

(3) You must maintain a log of records as specified in § 60.5420(c)(1) for each well completion operation conducted during the initial compliance period.

(4) For each gas well affected facility subject to both § 60.5375(a)(1) and (3), you must maintain records of one or more digital photographs with the date the photograph was taken and the latitude and longitude of the well site imbedded within or stored with the digital file showing the equipment for storing or re-injecting recovered liquid, equipment for routing recovered gas to the gas flow line and the completion combustion device (if applicable) connected to and operating at each gas well completion operation that occurred during the initial compliance period. As an alternative to imbedded latitude and longitude within the digital photograph, the digital photograph may consist of a photograph of the equipment connected and operating at each well completion operation with a photograph of a separately operating GIS device within the same digital picture, provided the latitude and longitude output of the GIS unit can be clearly read in the digital photograph.

(b)(1) To achieve initial compliance with standards for your centrifugal compressor affected facility you must reduce VOC emissions from each centrifugal compressor wet seal fluid degassing system by 95.0 percent or greater as required by § 60.5380 and as demonstrated by the requirements of § 60.5413.

(2) If you use a control device to reduce emissions, you must equip the wet seal fluid degassing system with a cover that meets the requirements of § 60.5411(b) and is connected through a closed vent system that meets the requirements of § 60.5411(a) to a control device that meets the conditions specified in § 60.5412.

(3) You must conduct an initial performance test as required in § 60.5413 within 180 days after initial startup or by October 15, 2012, whichever is later, and you must comply with the continuous compliance requirements in § 60.5415(b).

(4) You must conduct the initial inspections required in § 60.5416.

(5) You must install and operate the continuous parameter monitoring systems in accordance with § 60.5417.

(6) You must submit the notifications required in 60.7(a)(1), (3), and (4).

(7) You must submit the initial annual report for your centrifugal compressor affected facility as required in § 60.5420(b) for each centrifugal compressor affected facility

(8) You must maintain the records as specified in § 60.5420(c)(3).

(c) To achieve initial compliance with the standards for each reciprocating compressor affected facility you must comply with paragraphs (c)(1) through (4) of this section.

(1) During the initial compliance period, you must continuously monitor the number of hours of operation or track the number of months since the last rod packing replacement.

(2) You must submit the notifications required in 60.7(a)(1), (3), and (4).

(3) You must submit the initial annual report for your reciprocating compressor as required in § 60.5420(b).

(4) You must maintain the records as specified in § 60.5420(c)(3) for each reciprocating compressor affected facility.

(d) To achieve initial compliance with emission standards for your pneumatic controller affected facility you comply with the requirements specified in paragraphs (d)(1) through (6) of this section.

(1) If applicable, you have demonstrated by maintaining records as specified in § 60.5420(c)(4)(ii) of your determination that the use of a pneumatic controller affected facility with a bleed rate greater than 6 standard cubic feet of gas per hour is required as specified in § 60.5390(a).

(2) You own or operate a pneumatic controller affected facility located at a natural gas processing plant and your pneumatic controller is driven other than by use of natural gas and therefore emits zero natural gas.

(3) You own or operate a pneumatic controller affected facility located between the wellhead and a natural gas processing plant and the manufacturer's design specifications indicate that the controller emits less than or equal to 6 standard cubic feet of gas per hour.

(4) You must tag each new pneumatic controller affected facility according to the requirements of § 60.5390(b)(2).

(5) You must include the information in paragraph (d)(1) of this section and a listing of the pneumatic controller affected facilities specified in paragraphs (d)(2) and (3) of this section in the initial annual report submitted for your pneumatic controller affected facilities constructed, modified or reconstructed during the period covered by the annual report according to the requirements of § 60.5420(b).

(6) You must maintain the records as specified in § 60.5420(c)(4) for each pneumatic controller affected facility.

(e) To achieve initial compliance with the emission standards for your storage vessel affected facility you must comply with paragraphs (e)(1) through (9) of this section.

(1) You have determined the VOC emission rate within 30 days after startup for storage vessels constructed, modified or reconstructed at well sites with no other wells in production, and you must use good engineering practices to minimize emissions during the 30-day period.

(2) You must determine the VOC emission rate upon startup for storage vessels constructed, modified or reconstructed at well sites with one or more wells already in production.

(3) For storage vessel affected facilities emitting more than 6 tpy VOC, you must reduce VOC emissions by 95.0 percent or greater within 60 days after startup for storage vessels constructed, modified or reconstructed at well sites with no other wells in production, or upon startup for storage vessels constructed, modified or reconstructed at well sites with one or more wells already in production.

(4) If you use a control device to reduce emissions, you must equip the storage vessel with a cover that meets the requirements of § 60.5411(b) and is connected through a closed vent system that meets the requirements of § 60.5411(a) to a control device that meets the conditions specified in § 60.5412 within 60 days after startup for storage vessels constructed, modified

or reconstructed at well sites with no other wells in production, or upon startup for storage vessels constructed, modified or reconstructed at well sites with one or more wells already in production.

(5) You must conduct an initial performance test as required in § 60.5413 within 180 days after initial startup or within 180 days of October 15, 2013, whichever is later, and must conduct the compliance demonstration in § 60.5415(b).

(6) You must conduct the initial inspections required in § 60.5416.

(7) You must install and operate continuous parameter monitoring systems in accordance with § 60.5417.

(8) You must submit the information in paragraphs (e)(1) through (7) of this section in the initial annual report as required in § 60.5420(b).

(9) You must maintain the records as specified in § 60.5420(c)(5) for each storage vessel affected facility.

(f) For affected facilities at onshore natural gas processing plants, initial compliance with the VOC requirements is demonstrated if you are in compliance with the requirements of § 60.5400.

(g) For sweetening unit affected facilities at onshore natural gas processing plants, initial compliance is demonstrated according to paragraphs (g)(1) through (3) of this section.

(1) To determine compliance with the standards for SO_2 specified in § 60.5405(a), during the initial performance test as required by § 60.8, the minimum required sulfur dioxide emission reduction efficiency (Z_i) is compared to the emission reduction efficiency (R) achieved by the sulfur recovery technology as specified in paragraphs (g)(1)(i) and (ii) of this section.

(i) If $R \geq Z_i$, your affected facility is in compliance.

(ii) If $R < Z_i$, your affected facility is not in compliance.

(2) The emission reduction efficiency (R) achieved by the sulfur reduction technology must be determined using the procedures in § 60.5406(c)(1).

(3) You have submitted the results of paragraphs (g)(1) and (2) of this section in the initial annual report submitted for your sweetening unit affected facilities at onshore natural gas processing plants.

§ 60.5411 What additional requirements must I meet to determine initial compliance for my closed vent systems routing materials from storage vessels and centrifugal compressor wet seal degassing systems?

You must meet the applicable requirements of this section for each cover and closed vent system used to comply with the emission standards for your storage vessel or centrifugal compressor affected facility.

(a) *Closed vent system requirements.* (1) You must design the closed vent system to route all gases, vapors, and fumes emitted from the material in the storage vessel or wet seal fluid degassing system to a control device that meets the requirements specified in § 60.5412.

(2) You must design and operate the closed vent system with no detectable emissions as demonstrated by § 60.5416(b).

(3) You must meet the requirements specified in paragraphs (a)(3)(i) and (ii) of this section if the closed vent system contains one or more bypass devices that could be used to divert all or a portion of the gases, vapors, or fumes from entering the control device.

(i) Except as provided in paragraph (a)(3)(ii) of this section, you must comply with either paragraph (a)(3)(i)(A) or (B) of this section for each bypass device.

(A) You must properly install, calibrate, maintain, and operate a flow indicator at the inlet to the bypass device that could divert the stream away from the control device to the atmosphere that is capable of taking periodic readings as specified in § 60.5416(a)(4) and sounds an alarm when the bypass device is open such that the stream is being, or could be, diverted away from the control device to the atmosphere.

(B) You must secure the bypass device valve installed at the inlet to the bypass device in the non-diverting position using a car-seal or a lock-and-key type configuration.

(ii) Low leg drains, high point bleeds, analyzer vents, open-ended valves or lines, and safety devices are not subject to the requirements of paragraph (a)(3)(i) of this section.

(b) *Cover requirements.* (1) The cover and all openings on the cover (*e.g.,* access hatches, sampling ports, and gauge wells) shall form a continuous barrier over the entire surface area of the liquid in the storage vessel or wet seal fluid degassing system.

(2) Each cover opening shall be secured in a closed, sealed position (*e.g.,* covered by a gasketed lid or cap) whenever material is in the unit on which the cover is installed except during those times when it is necessary to use an opening as follows:

(i) To add material to, or remove material from the unit (this includes openings necessary to equalize or balance the internal pressure of the unit following changes in the level of the material in the unit);

(ii) To inspect or sample the material in the unit;

(iii) To inspect, maintain, repair, or replace equipment located inside the unit; or

(iv) To vent liquids, gases, or fumes from the unit through a closed-vent system to a control device designed and operated in accordance with the requirements of paragraph (a) of this section.

§ 60.5412 What additional requirements must I meet for determining initial compliance with control devices used to comply with the emission standards for my storage vessel or centrifugal compressor affected facility?

You must meet the applicable requirements of this section for each control device used to comply with the emission standards for your storage vessel or centrifugal compressor affected facility.

(a) If you use a control device to meet the emission reduction standard in § 60.5380(a)(1) for your centrifugal compressor or § 60.5395(a)(1) or (2) for your storage vessel, you must use one of the control devices specified in paragraphs (a)(1) through (3) of this section. You must demonstrate that the control device achieves the performance requirements using the performance test methods and procedures specified in § 60.5413.

(1) You must design and operate an enclosed combustion device (*e.g.,* thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater) in accordance with one of the performance requirements specified in paragraphs (a)(1)(i) through (iv) of this section.

(i) You must reduce the mass content of VOC in the gases vented to the device by 95.0 percent by weight or greater as determined in accordance with the requirements of § 60.5413.

(ii) You must reduce the concentration of TOC in the exhaust gases at the outlet to the device to a level equal to or less than 20 parts per million by volume on a dry basis corrected to 3 percent oxygen as determined in accordance with the requirements of § 60.5413.

(iii) You must operate at a minimum temperature of 760 °C for a control device that can demonstrate a uniform combustion zone temperature during the performance test conducted under § 60.5413.

(iv) If a boiler or process heater is used as the control device, then you must introduce the vent stream into the flame zone of the boiler or process heater.

(2) You must design and operate a vapor recovery device (*e.g.*, carbon adsorption system or condenser) or other non-destructive control device to reduce the mass content of VOC in the gases vented to the device by 95.0 percent by weight or greater as determined in accordance with the requirements of § 60.5413. The vapor recovery device must meet the design analysis requirements of § 60.5413(c).

(3) You must design and operate a flare in accordance with the requirements of § 60.5413.

(b) You must operate each control device in accordance with the requirements specified in paragraphs (b)(1) and (2) of this section.

(1) You must operate each control device used to comply with this subpart at all times when gases, vapors, and fumes are vented from the storage vessel affected facility, as required under § 60.5395, or wet seal fluid degassing system affected facility, as required under § 60.5380, through the closed vent system to the control device. You may vent more than one affected facility to a control device used to comply with this subpart.

(2) For each control device monitored in accordance with the requirements of § 60.5417, you must demonstrate compliance according to the requirements of § 60.5415(e)(2), as applicable.

(c) For each carbon adsorption system used as a control device to meet the requirements of paragraph (a)(2) of this section, you must manage the carbon in accordance with the requirements specified in paragraphs (c)(1) or (2) of this section.

(1) Following the initial startup of the control device, you must replace all carbon in the control device with fresh carbon on a regular, predetermined time interval that is no longer than the carbon service life established according to § 60.5413(c)(2) or (3) for the carbon adsorption system. You must maintain records identifying the schedule for replacement and records of each carbon replacement as required in § 60.5420(c)(6).

(2) You must either regenerate, reactivate, or burn the spent carbon removed from the carbon adsorption system in one of the units specified in paragraphs (c)(2)(i) through (vii) of this section.

(i) Regenerate or reactivate the spent carbon in a thermal treatment unit for which you have been issued a final permit under 40 CFR part 270 that implements the requirements of 40 CFR part 264, subpart X.

(ii) Regenerate or reactivate the spent carbon in a thermal treatment unit equipped with and operating air emission controls in accordance with this section.

(iii) Regenerate or reactivate the spent carbon in a thermal treatment unit equipped with and operating organic air emission controls in accordance with an emissions standard for VOC under another subpart in 40 CFR part 60 or this part.

(iv) Burn the spent carbon in a hazardous waste incinerator for which the owner or operator has been issued a final permit under 40 CFR part 270 that implements the requirements of 40 CFR part 264, subpart O.

(v) Burn the spent carbon in a hazardous waste incinerator which you have designed and operated in accordance with the requirements of 40 CFR part 265, subpart O.

(vi) Burn the spent carbon in a boiler or industrial furnace for which you have been issued a final permit under 40 CFR part 270 that implements the requirements of 40 CFR part 266, subpart H.

(vii) Burn the spent carbon in a boiler or industrial furnace that you have designed and operated in accordance with the interim status requirements of 40 CFR part 266, subpart H.

§ 60.5413 What are the performance testing procedures for control devices used to demonstrate compliance at my storage vessel or centrifugal compressor affected facility?

This section applies to the performance testing of control devices used to demonstrate compliance with the emissions standards for your storage vessel or centrifugal compressor affected facility. You must demonstrate that a control device achieves the performance requirements of § 60.5412(a) using the performance test methods and procedures specified in paragraph (b) of this section. For condensers, you may use a design analysis as specified in paragraph (c) of this section in lieu of complying with paragraph (b) of this section.

(a) *Performance test exemptions.* You are exempt from the requirements to conduct performance tests and design analyses if you use any of the control devices described in paragraphs (a)(1) through (7) of this section.

(1) A flare that is designed and operated in accordance with § 60.18(b). You must conduct the compliance determination using Method 22 at 40 CFR part 60, appendix A–7, to determine visible emissions.

(2) A boiler or process heater with a design heat input capacity of 44 megawatts or greater.

(3) A boiler or process heater into which the vent stream is introduced with the primary fuel or is used as the primary fuel.

(4) A boiler or process heater burning hazardous waste for which you have either been issued a final permit under 40 CFR part 270 and comply with the requirements of 40 CFR part 266, subpart H; or you have certified compliance with the interim status requirements of 40 CFR part 266, subpart H.

(5) A hazardous waste incinerator for which you have been issued a final permit under 40 CFR part 270 and comply with the requirements of 40 CFR part 264, subpart O; or you have certified compliance with the interim status requirements of 40 CFR part 265, subpart O.

(6) A performance test is waived in accordance with § 60.8(b).

(7) A control device that can be demonstrated to meet the performance requirements of § 60.5412(a) through a performance test conducted by the manufacturer, as specified in paragraph (d) of this section.

(b) *Test methods and procedures.* You must use the test methods and procedures specified in paragraphs (b)(1) through (5) of this section, as applicable, for each performance test conducted to demonstrate that a control device meets the requirements of § 60.5412(a). You must conduct the initial and periodic performance tests according to the schedule specified in paragraph (b)(5) of this section.

(1) You must use Method 1 or 1A at 40 CFR part 60, appendix A–1, as appropriate, to select the sampling sites specified in paragraphs (b)(1)(i) and (ii) of this section. Any references to particulate mentioned in Methods 1 and 1A do not apply to this section.

(i) Sampling sites must be located at the inlet of the first control device, and at the outlet of the final control device, to determine compliance with the control device percent reduction requirement specified in § 60.5412(a)(1)(i) or (a)(2).

(ii) The sampling site must be located at the outlet of the combustion device to determine compliance with the enclosed combustion device total TOC concentration limit specified in § 60.5412(a)(1)(ii).

(2) You must determine the gas volumetric flowrate using Method 2, 2A, 2C, or 2D at 40 CFR part 60, appendix A–2, as appropriate.

(3) To determine compliance with the control device percent reduction performance requirement in § 60.5412(a)(1)(i) or (a)(2), you must use Method 25A at 40 CFR part 60, appendix A–7. You must use the procedures in paragraphs (b)(3)(i)

through (iv) of this section to calculate percent reduction efficiency.

(i) For each run, you must take either an integrated sample or a minimum of four grab samples per hour. If grab sampling is used, then the samples must be taken at approximately equal intervals in time, such as 15-minute intervals during the run.

(ii) You must compute the mass rate of TOC (minus methane and ethane) using the equations and procedures specified in paragraphs (b)(3)(ii)(A) and (B) of this section.

(A) You must use the following equations:

$$E_i = K_2\left(\sum_{j=1}^{n} C_{ij}M_{ij}\right)Q_i$$

$$E_o = K_2\left(\sum_{j=1}^{n} C_{oj}M_{oj}\right)Q_o$$

Where:

E_i, E_o = Mass rate of TOC (minus methane and ethane) at the inlet and outlet of the control device, respectively, dry basis, kilogram per hour.

K_2 = Constant, 2.494×10^{-6} (parts per million) (gram-mole per standard cubic meter) (kilogram/gram) (minute/hour), where standard temperature (gram-mole per standard cubic meter) is 20 °C.

C_{ij}, C_{oj} = Concentration of sample component j of the gas stream at the inlet and outlet of the control device, respectively, dry basis, parts per million by volume.

M_{ij}, M_{oj} = Molecular weight of sample component j of the gas stream at the inlet and outlet of the control device, respectively, gram/gram-mole.

Q_i, Q_o = Flowrate of gas stream at the inlet and outlet of the control device, respectively, dry standard cubic meter per minute.

n = Number of components in sample.

(B) When calculating the TOC mass rate, you must sum all organic compounds (minus methane and ethane) measured by Method 25A at 40 CFR part 60, appendix A–7 using the equations in paragraph (b)(3)(ii)(A) of this section.

(iii) You must calculate the percent reduction in TOC (minus methane and ethane) as follows:

$$R_{cd} = \frac{E_i - E_o}{E_i} * 100\%$$

Where:

R_{cd} = Control efficiency of control device, percent.

E_i = Mass rate of TOC (minus methane and ethane) at the inlet to the control device as calculated under paragraph (b)(3)(ii) of this section, kilograms TOC per hour or kilograms HAP per hour.

E_o = Mass rate of TOC (minus methane and ethane) at the outlet of the control device, as calculated under paragraph (b)(3)(ii) of this section, kilograms TOC per hour per hour.

(iv) If the vent stream entering a boiler or process heater with a design capacity less than 44 megawatts is introduced with the combustion air or as a secondary fuel, you must determine the weight-percent reduction of total TOC (minus methane and ethane) across the device by comparing the TOC (minus methane and ethane) in all combusted vent streams and primary and secondary fuels with the TOC (minus methane and ethane) exiting the device, respectively.

(4) You must use Method 25A at 40 CFR part 60, appendix A–7 to measure TOC (minus methane and ethane) to determine compliance with the enclosed combustion device total VOC concentration limit specified in § 60.5412(a)(1)(ii). You must calculate parts per million by volume concentration and correct to 3 percent oxygen, using the procedures in paragraphs (b)(4)(i) through (iii) of this section.

(i) For each run, you must take either an integrated sample or a minimum of four grab samples per hour. If grab sampling is used, then the samples must be taken at approximately equal intervals in time, such as 15-minute intervals during the run.

(ii) You must calculate the TOC concentration for each run as follows:

$$C_{TOC} = \sum_{i=1}^{x} \frac{\left(\sum_{j=i}^{n} C_{ji}\right)}{x}$$

Where:

C_{TOC} = Concentration of total organic compounds minus methane and ethane, dry basis, parts per million by volume.

C_{ji} = Concentration of sample component j of sample i, dry basis, parts per million by volume.

n = Number of components in the sample.

x = Number of samples in the sample run.

(iii) You must correct the TOC concentration to 3 percent oxygen as specified in paragraphs (b)(4)(iii)(A) and (B) of this section.

(A) You must use the emission rate correction factor for excess air, integrated sampling and analysis procedures of Method 3A or 3B at 40 CFR part 60, appendix A, ASTM D6522–00 (Reapproved 2005), or ANSI/ASME PTC 19.10–1981, Part 10 (manual portion only) (incorporated by reference as specified in § 60.17) to determine the oxygen concentration. The samples must be taken during the same time that the samples are taken for determining TOC concentration.

(B) You must correct the TOC concentration for percent oxygen as follows:

$$C_c = C_m\left(\frac{17.9}{20.9 - \%O_{2d}}\right)$$

Where:

C_c = TOC concentration corrected to 3 percent oxygen, dry basis, parts per million by volume.

C_m = TOC concentration, dry basis, parts per million by volume.

$\%O_{2d}$ = Concentration of oxygen, dry basis, percent by volume.

(5) You must conduct performance tests according to the schedule specified in paragraphs (b)(5)(i) and (ii) of this section.

(i) You must conduct an initial performance test within 180 days after initial startup for your affected facility. You must submit the performance test results as required in § 60.5420(b)(7).

(ii) You must conduct periodic performance tests for all control devices required to conduct initial performance tests except as specified in paragraphs (b)(5)(ii)(A) and (B) of this section. You must conduct the first periodic performance test no later than 60 months after the initial performance test required in paragraph (b)(5)(i) of this section. You must conduct subsequent periodic performance tests at intervals no longer than 60 months following the previous periodic performance test or whenever you desire to establish a new operating limit. You must submit the periodic performance test results as specified in § 60.5420(b)(7). Combustion control devices meeting the criteria in either paragraph (b)(5)(ii)(A) or (B) of this section are not required to conduct periodic performance tests.

(A) A control device whose model is tested under, and meets the criteria of paragraph (d) of this section.

(B) A combustion control device tested under paragraph (b) of this section that meets the outlet TOC performance level specified in § 60.5412(a)(1)(ii) and that establishes a correlation between firebox or combustion chamber temperature and the TOC performance level.

(c) *Control device design analysis to meet the requirements of § 60.5412(a).* (1) For a condenser, the design analysis must include an analysis of the vent stream composition, constituent concentrations, flowrate, relative humidity, and temperature, and must establish the design outlet organic compound concentration level, design average temperature of the condenser exhaust vent stream, and the design

average temperatures of the coolant fluid at the condenser inlet and outlet.

(2) For a regenerable carbon adsorption system, the design analysis shall include the vent stream composition, constituent concentrations, flowrate, relative humidity, and temperature, and shall establish the design exhaust vent stream organic compound concentration level, adsorption cycle time, number and capacity of carbon beds, type and working capacity of activated carbon used for the carbon beds, design total regeneration stream flow over the period of each complete carbon bed regeneration cycle, design carbon bed temperature after regeneration, design carbon bed regeneration time, and design service life of the carbon.

(3) For a nonregenerable carbon adsorption system, such as a carbon canister, the design analysis shall include the vent stream composition, constituent concentrations, flowrate, relative humidity, and temperature, and shall establish the design exhaust vent stream organic compound concentration level, capacity of the carbon bed, type and working capacity of activated carbon used for the carbon bed, and design carbon replacement interval based on the total carbon working capacity of the control device and source operating schedule. In addition, these systems will incorporate dual carbon canisters in case of emission breakthrough occurring in one canister.

(4) If you and the Administrator do not agree on a demonstration of control device performance using a design analysis, then you must perform a performance test in accordance with the requirements of paragraph (b) of this section to resolve the disagreement. The Administrator may choose to have an authorized representative observe the performance test.

(d) *Performance testing for combustion control devices—manufacturers' performance test.* The manufacturer must demonstrate that a specific model of combustion control device achieves the performance requirements in paragraph (d)(1) of this section by conducting a performance test as specified in paragraphs (d)(2) through (8) of this section. You must submit a test report for each combustion control device in accordance with the requirements in paragraphs (d)(9) of this section.

(1) The manufacturer must meet the performance test criteria in paragraphs (d)(1)(i) through (iii) of this section.

(i) The control device model tested must meet the emission levels in paragraphs (d)(1)(i)(A) through (C) of this section.

(A) Method 22 at 40 CFR part 60, appendix A–7, results under paragraph (d)(6)(iv) of this section with no indication of visible emissions.

(B) Average Method 25A at 40 CFR part 60, appendix A–7, results under paragraph (d)(8) of this section equal to or less than 10.0 parts per million by volume-wet THC as propane corrected to 3.0 percent carbon dioxide, and

(C) Average carbon monoxide emissions determined under paragraph (d)(6)(iii) of this section equal to or less than 10 parts per million by volume-dry, corrected to 3.0 percent carbon dioxide.

(ii) The manufacturer must determine a maximum inlet gas flow rate, which must not be exceeded for each control device model to achieve the criteria in paragraph (d)(1)(i) of this section.

(iii) A control device meeting the emission levels in paragraph (d)(1)(i)(A) through (C) of this section must demonstrate a minimum destruction efficiency of 95.0 percent for VOC regulated under this subpart.

(2) Performance testing must consist of three one-hour (or longer) test runs for each of the four firing rate settings in paragraphs (d)(2)(i) through (iv) of this section, making a total of 12 test runs per test. The manufacturer must use propene (propylene) gas for the testing fuel. An independent third-party laboratory (not affiliated with the control device manufacturer or fuel supplier) must perform all fuel analyses.

(i) 90–100 percent of maximum design rate (fixed rate).

(ii) 70–100–70 percent (ramp up, ramp down). Begin the test at 70 percent of the maximum design rate. Within the first 5 minutes, ramp up the firing rate to 100 percent of the maximum design rate. Hold at 100 percent for 5 minutes. In the 10–15 minute time range, ramp back down to 70 percent of the maximum design rate. Repeat three more times for a total of 60 minutes of sampling.

(iii) 30–70–30 percent (ramp up, ramp down). Begin the test at 30 percent of the maximum design rate. Within the first 5 minutes, ramp up the firing rate to 70 percent of the maximum design rate. Hold at 70 percent for 5 minutes. In the 10–15 minute time range, ramp back down to 30 percent of the maximum design rate. Repeat three more times for a total of 60 minutes of sampling.

(iv) 0–30–0 percent (ramp up, ramp down). Begin the test at 0 percent of the maximum design rate. Within the first 5 minutes, ramp up the firing rate to 100 percent of the maximum design rate. Hold at 30 percent for 5 minutes. In the 10–15 minute time range, ramp back down to 0 percent of the maximum design rate. Repeat three more times for a total of 60 minutes of sampling.

(3) The manufacturer must test all models employing multiple enclosures simultaneously and with all burners operational. The manufacturer must report results for each enclosure individually and for the average of the emissions from all interconnected combustion enclosures/chambers. Control device operating data must be collected continuously throughout the performance test using an electronic Data Acquisition System and strip chart. The manufacturer must submit data with the test report in accordance with paragraph (d)(9) of this section.

(4) The manufacturer must conduct inlet testing as specified in paragraphs (d)(4)(i) through (iii) of this section.

(i) The fuel flow metering system must be located in accordance with Method 2A at 40 CFR part 60, appendix A–1, (or other approved procedure) to measure fuel flow rate at the control device inlet location. You must position the fitting for filling fuel sample containers a minimum of eight pipe diameters upstream of any inlet fuel flow monitoring meter.

(ii) The manufacturer must determine the inlet flow rate using Method 2A at 40 CFR part 60, appendix A–1. Record the start and stop reading for each 60-minute THC test. Record the gas pressure and temperature at 5-minute intervals throughout each 60-minute THC test.

(iii) The manufacturer must conduct inlet fuel sampling in accordance with the criteria in paragraph (d)(5) of this section.

(5) The manufacturer must conduct inlet fuel sampling as specified in paragraphs (d)(5)(i) and (ii) of this section.

(i) At the inlet fuel sampling location, the manufacturer must securely connect a Silonite-coated stainless steel evacuated canister fitted with a flow controller sufficient to fill the canister over a 1 hour period. Filling must be conducted as specified in paragraphs (d)(5)(i)(A) through (C) of this section.

(A) Open the canister sampling valve at the beginning of the total hydrocarbon test, and close the canister at the end of the total hydrocarbon test.

(B) Fill one canister for each total hydrocarbon test run.

(C) Label the canisters individually and record on a chain of custody form.

(ii) The manufacturer must analyze each fuel sample using the methods in paragraphs (d)(5)(ii)(A) through (D) of this section. You must include the results in the test report in paragraph (d)(9) of this section.

(A) Hydrocarbon compounds containing between one and five atoms of carbon plus benzene using ASTM D1945–03 (Reapproved 2010) (incorporated by reference as specified in § 60.17).

(B) Hydrogen (H_2), carbon monoxide (CO), carbon dioxide (CO_2), nitrogen (N_2), oxygen (O_2) using ASTM D1945–03 (Reapproved 2010) (incorporated by reference as specified in § 60.17).

(C) Carbonyl sulfide, carbon disulfide plus mercaptans using ASTM D5504–08 (incorporated by reference as specified in § 60.17).

(D) Higher heating value using ASTM D3588–98 (Reapproved 2003) or ASTM D4891–89 (Reapproved 2006) (incorporated by reference as specified in § 60.17).

(6) The manufacturer must conduct outlet testing in accordance with the criteria in paragraphs (d)(6)(i) through (iv) and (d)(7) of this section.

(i) The manufacturer must sample and measure flowrate in accordance with the following:

(A) The manufacturer must position the outlet sampling location a minimum of four equivalent stack diameters downstream from the highest peak flame or any other flow disturbance, and a minimum of one equivalent stack diameter upstream of the exit or any other flow disturbance. A minimum of two sample ports must be used.

(B) The manufacturer must measure flow rate using Method 1 at 40 CFR part 60, appendix A–1 for determining flow measurement traverse point location, and Method 2 at 40 CFR part 60, appendix A–1 for measuring duct velocity. If low flow conditions are encountered (*i.e.,* velocity pressure differentials less than 0.05 inches of water) during the performance test, a more sensitive manometer must be used to obtain an accurate flow profile.

(ii) The manufacturer must determine molecular weight as specified in paragraph (d)(7) of this section.

(iii) The manufacturer must determine carbon monoxide using Method 10 at 40 CFR part 60, appendix A–4 or ASTM D6522–00 (Reapproved 2005) (incorporated by reference as specified in § 60.17). The manufacturer must run the test at the same time and with the sample points used for the Method 25A at 40 CFR part 60, appendix A–7, testing. An instrument range of 0–10 parts per million by volume-dry (ppmvd) must be used.

(iv) The manufacturer must determine visible emissions using Method 22 at 40 CFR part 60, appendix A–7. The test must be performed continuously during each test run. A digital color photograph of the exhaust point, taken from the position of the observer and annotated with date and time, will be taken once per test run and the four photos included in the test report.

(7) The manufacturer must determine molecular weight as specified in paragraphs (d)(7)(i) and (ii) of this section.

(i) The manufacturer must collect an integrated bag sample during the Method 4 at 40 CFR part 60, appendix A–3, moisture test. The manufacturer must analyze the bag sample using a gas chromatograph-thermal conductivity detector (GC–TCD) analysis meeting the criteria in paragraphs (d)(7)(i)(A) through (D) of this section.

(A) Collect the integrated sample throughout the entire test, and collect representative volumes from each traverse location.

(B) Purge the sampling line with stack gas before opening the valve and beginning to fill the bag.

(C) Knead or otherwise vigorously mix the bag contents prior to the gas chromatograph analysis.

(D) Modify the gas chromatograph-thermal conductivity detector calibration procedure in Method 3C at 40 CFR part 60, appendix A–2 by using EPA Alt–045 as follows: For the initial calibration, triplicate injections of any single concentration must agree within 5 percent of their mean to be valid. The calibration response factor for a single concentration re-check must be within 10 percent of the original calibration response factor for that concentration. If this criterion is not met, repeat the initial calibration using at least three concentration levels.

(ii) The manufacturer must report the molecular weight of oxygen, carbon dioxide, methane, and nitrogen and include in the test report submitted under § 60.5420(b)(7). The manufacturer must determine moisture using Method 4 at 40 CFR part 60, appendix A–3. Traverse both ports with the Method 4 at 40 CFR part 60, appendix A–3, sampling train during each test run. The manufacturer must not introduce ambient air into the Method 3C at 40 CFR part 60, appendix A–2, integrated bag sample during the port change.

(8) The manufacturer must determine total hydrocarbons as specified by the criteria in paragraphs (d)(8)(i) through (vii) of this section.

(i) Conduct THC sampling using Method 25A at 40 CFR part 60, appendix A–7, except the option for locating the probe in the center 10 percent of the stack is not allowed. The THC probe must be traversed to 16.7 percent, 50 percent, and 83.3 percent of the stack diameter during the testing.

(ii) A valid test must consist of three Method 25A at 40 CFR part 60, appendix A–7, tests, each no less than 60 minutes in duration.

(iii) A 0–10 parts per million by volume-wet (ppmvw) (as propane) measurement range is preferred; as an alternative a 0–30 ppmvw (as carbon) measurement range may be used.

(iv) Calibration gases will be propane in air and be certified through EPA Protocol 1—"EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards," September 1997, as amended August 25, 1999, EPA–600/R–97/121.

(v) THC measurements must be reported in terms of ppmvw as propane.

(vi) THC results must be corrected to 3 percent CO_2, as measured by Method 3C at 40 CFR part 60, appendix A–2.

(vii) Subtraction of methane/ethane from the THC data is not allowed in determining results.

(9) For each combustion control device model tested by the manufacturer under this section, you must maintain records of the information listed in paragraphs (d)(9)(i) through (vi) of this section.

(i) A full schematic of the control device and dimensions of the device components.

(ii) The design net heating value (minimum and maximum) of the device.

(iii) The test fuel gas flow range (in both mass and volume). Include the minimum and maximum allowable inlet gas flow rate.

(iv) The air/stream injection/assist ranges, if used.

(v) The test parameter ranges listed in paragraphs (d)(9)(v)(A) through (O) of this section, as applicable for the tested model.

(A) Fuel gas delivery pressure and temperature.

(B) Fuel gas moisture range.

(C) Purge gas usage range.

(D) Condensate (liquid fuel) separation range.

(E) Combustion zone temperature range. This is required for all devices that measure this parameter.

(F) Excess combustion air range.

(G) Flame arrestor(s).

(H) Burner manifold pressure.

(I) Pilot flame sensor.

(J) Pilot flame design fuel and fuel usage.

(K) Tip velocity range.

(L) Momentum flux ratio.

(M) Exit temperature range.

(N) Exit flow rate.

(O) Wind velocity and direction.

(vi) You must include all calibration quality assurance/quality control data, calibration gas values, gas cylinder certification, and strip charts annotated

with test times and calibration values in the test report.

§ 60.5415 How do I demonstrate continuous compliance with the standards for my gas well affected facility, my centrifugal compressor affected facility, my stationary reciprocating compressor affected facility, my pneumatic controller affected facility, my storage vessel affected facility, and my affected facilities at onshore natural gas processing plants?

(a) For each gas well affected facility, you must demonstrate continuous compliance by submitting the reports required by § 60.5420(b) and maintaining the records for each completion operation specified in § 60.5420(c)(1).

(b) For each centrifugal compressor affected facility, you must demonstrate continuous compliance according to paragraphs (b)(1) and (2) of this section.

(1) You must reduce VOC emissions from the wet seal fluid degassing system by 95.0 percent or greater.

(2) If you use a control device to reduce emissions, you must demonstrate continuous compliance according to paragraph (e)(2) of this section.

(3) You must submit the annual report required by 60.5420(b) and maintain the records as specified in § 60.5420(c)(2).

(c) For each reciprocating compressor affected facility, you must demonstrate continuous compliance according to paragraphs (c)(1) through (3) of this section.

(1) You must continuously monitor the number of hours of operation for each reciprocating compressor affected facility or track the number of months since initial startup, or October 15, 2012, or the date of the most recent reciprocating compressor rod packing replacement, whichever is later.

(2) You must submit the annual report as required in § 60.5420(b) and maintain records as required in § 60.5420(c)(3).

(3) You must replace the reciprocating compressor rod packing before the total number of hours of operation reaches 26,000 hours or the number of months since the most recent rod packing replacement reaches 36 months.

(d) For each pneumatic controller affected facility, you must demonstrate continuous compliance according to paragraphs (d)(1) through (3) of this section.

(1) You must continuously operate the pneumatic controllers as required in § 60.5390(a), (b), or (c).

(2) You must submit the annual report as required in § 60.5420(b).

(3) You must maintain records as required in § 60.5420(c)(4).

(e) For each storage vessel affected facility for which the VOC emissions are greater than 6 tpy, you must demonstrate continuous compliance according to paragraphs (e)(1) and (2) of this section.

(1) You must reduce VOC emissions from each storage vessel are reduced by 95.0 percent or greater.

(2) If you use a control device to reduce VOC emissions, you must demonstrate continuous compliance with the performance requirements of § 60.5412(a)(2) using the procedure specified in paragraphs (e)(2)(i) through (vii) of this section. If you use a condenser as the control device to achieve the requirements specified in § 60.5412(a)(2), you may demonstrate compliance according to paragraph (e)(2)(viii) of this section. You may switch between compliance with paragraphs (e)(2)(i) through (vii) of this section and compliance with paragraph (e)(2)(viii) of this section only after at least 1 year of operation in compliance with the selected approach. You must provide notification of such a change in the compliance method in the next Annual Report, as required in § 60.5420(b), following the change.

(i) You must operate below (or above) the site specific maximum (or minimum) parameter value established according to the requirements of § 60.5417(f)(1).

(ii) You must calculate the daily average of the applicable monitored parameter in accordance with § 60.5417(e) except that the inlet gas flow rate to the control device must not be averaged.

(iii) Compliance with the operating parameter limit is achieved when the daily average of the monitoring parameter value calculated under paragraph (e)(2)(ii) of this section is either equal to or greater than the minimum monitoring value or equal to or less than the maximum monitoring value established under paragraph (e)(2)(i) of this section. When performance testing of a combustion control device is conducted by the device manufacturer as specified in § 60.5413(d), compliance with the operating parameter limit is achieved when the inlet gas flow rate is equal to or less than the value established under § 60.5413(d)(1)(ii).

(iv) You must operate the continuous monitoring system required in § 60.5417 at all times the affected source is operating, except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities (including, as applicable, system accuracy audits and required zero and span adjustments). A monitoring system malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring system to provide valid data. Monitoring system failures that are caused in part by poor maintenance or careless operation are not malfunctions. You are required to complete monitoring system repairs in response to monitoring system malfunctions and to return the monitoring system to operation as expeditiously as practicable.

(v) You may not use data recorded during monitoring system malfunctions, repairs associated with monitoring system malfunctions, or required monitoring system quality assurance or control activities in calculations used to report emissions or operating levels. You must use all the data collected during all other required data collection periods to assess the operation of the control device and associated control system.

(vi) Failure to collect required data is a deviation of the monitoring requirements, except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required quality monitoring system quality assurance or quality control activities (including, as applicable, system accuracy audits and required zero and span adjustments).

(vii) If you use a combustion control device to meet the requirements of § 60.5412(a), you must demonstrate compliance by installing a device tested under the provisions in § 60.5413(d) and complying with the criteria in paragraphs (e)(2)(vii)(A) through (D) of this section.

(A) The inlet gas flow rate must meet the range specified by the manufacturer. You must measure the flow rate as specified in § 60.5417(d)(1)(viii)(A).

(B) A pilot flame must be present at all times of operation. You must monitor the pilot flame in accordance with § 60.5417(d)(1)(viii)(B).

(C) You must operate the combustion control device with no visible emissions, except for periods not to exceed a total of 5 minutes during any 2 consecutive hours. You must perform a visible emissions test using Method 22 at 40 CFR part 60, appendix A–7 monthly. The observation period must be 2 hours and must follow Method 22.

(D) Compliance with the operating parameter limit is achieved when the criteria in paragraphs (e)(2)(vii)(D)(*1*) through (*5*) are met.

(*1*) The inlet gas flow rate monitored under paragraph (e)(2)(vii)(A) of this section is equal to or below the maximum established by the manufacturer.

(*2*) The pilot flame is present at all times; and

(*3*) During the visible emissions test performed under paragraph (e)(2)(vii)(C) of this section, the duration of visible emissions does not exceed a total of 5 minutes during the observation period. Devices failing the visible emissions test must follow the requirements in paragraphs (e)(2)(vii)(D)(*4*) and (*5*) of this section.

(*4*) Following the first failure, you must replace the fuel nozzle(s) and burner tubes.

(*5*) If, following replacement of the fuel nozzle(s) and burner tubes as specified in paragraph (e)(2)(vii)(D)(*4*) of this section, the visible emissions test is not passed in the next scheduled test, you must either conduct a performance test as specified in § 60.5413, or replace the device with another control device whose model was tested and meets the requirements in § 60.5413(d).

(viii) If you use a condenser as the control device to achieve the percent reduction performance requirements specified in § 60.5412(a)(2), you must demonstrate compliance using the procedures in paragraphs (e)(2)(viii)(A) through (E) of this section.

(A) You must establish a site-specific condenser performance curve according to § 60.5417(f)(2).

(B) You must calculate the daily average condenser outlet temperature in accordance with § 60.5417(e).

(C) You must determine the condenser efficiency for the current operating day using the daily average condenser outlet temperature calculated under paragraph (e)(2)(viii)(B) of this section and the condenser performance curve established under paragraph (e)(2)(viii)(A) of this section.

(D) Except as provided in paragraphs (e)(2)(viii)(D)(*1*) and (*2*) of this section, at the end of each operating day, you must calculate the 365-day rolling average TOC emission reduction, as appropriate, from the condenser efficiencies as determined in paragraph (e)(2)(viii)(C) of this section.

(*1*) After the compliance dates specified in § 60.5370, if you have less than 120 days of data for determining average TOC emission reduction, you must calculate the average TOC emission reduction for the first 120 days of operation after the compliance dates. You have demonstrated compliance with the overall 95.0 percent reduction requirement if the 120-day average TOC emission reduction is equal to or greater than 95.0 percent.

(*2*) After 120 days and no more than 364 days of operation after the compliance date specified in § 60.5370, you must calculate the average TOC emission reduction as the TOC emission reduction averaged over the number of days between the current day and the applicable compliance date. You have demonstrated compliance with the overall 95.0 percent reduction requirement, if the average TOC emission reduction is equal to or greater than 95.0 percent.

(E) If you have data for 365 days or more of operation, you have demonstrated compliance with the TOC emission reduction if the rolling 365-day average TOC emission reduction calculated in paragraph (e)(2)(viii)(D) of this section is equal to or greater than 95.0 percent.

(f) For affected facilities at onshore natural gas processing plants, continuous compliance with VOC requirements is demonstrated if you are in compliance with the requirements of § 60.5400.

(g) For each sweetening unit affected facility at onshore natural gas processing plants, you must demonstrate continuous compliance with the standards for SO_2 specified in § 60.5405(b) according to paragraphs (g)(1) and (2) of this section.

(1) The minimum required SO_2 emission reduction efficiency (Z_c) is compared to the emission reduction efficiency (R) achieved by the sulfur recovery technology.

(i) If $R \geq Z_c$, your affected facility is in compliance.

(ii) If $R < Z_c$, your affected facility is not in compliance.

(2) The emission reduction efficiency (R) achieved by the sulfur reduction technology must be determined using the procedures in § 60.5406(c)(1).

(h) *Affirmative defense for violations of emission standards during malfunction.* In response to an action to enforce the standards set forth in §§ 60.5375, 60.5380, 60.5385, 60.5390, 60.5395, 60.5400, and 60.5405, you may assert an affirmative defense to a claim for civil penalties for violations of such standards that are caused by malfunction, as defined at § 60.2. Appropriate penalties may be assessed, however, if you fail to meet your burden of proving all of the requirements in the affirmative defense. The affirmative defense shall not be available for claims for injunctive relief.

(1) To establish the affirmative defense in any action to enforce such a standard, you must timely meet the reporting requirements in § 60.5420(a), and must prove by a preponderance of evidence that:

(i) The violation:

(A) Was caused by a sudden, infrequent, and unavoidable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner; and

(B) Could not have been prevented through careful planning, proper design or better operation and maintenance practices; and

(C) Did not stem from any activity or event that could have been foreseen and avoided, or planned for; and

(D) Was not part of a recurring pattern indicative of inadequate design, operation, or maintenance; and

(ii) Repairs were made as expeditiously as possible when a violation occurred. Off-shift and overtime labor were used, to the extent practicable to make these repairs; and

(iii) The frequency, amount and duration of the violation (including any bypass) were minimized to the maximum extent practicable; and

(iv) If the violation resulted from a bypass of control equipment or a process, then the bypass was unavoidable to prevent loss of life, personal injury, or severe property damage; and

(v) All possible steps were taken to minimize the impact of the violation on ambient air quality, the environment and human health; and

(vi) All emissions monitoring and control systems were kept in operation if at all possible, consistent with safety and good air pollution control practices; and

(vii) All of the actions in response to the violation were documented by properly signed, contemporaneous operating logs; and

(viii) At all times, the affected source was operated in a manner consistent with good practices for minimizing emissions; and

(ix) A written root cause analysis has been prepared, the purpose of which is to determine, correct, and eliminate the primary causes of the malfunction and the violation resulting from the malfunction event at issue. The analysis shall also specify, using best monitoring methods and engineering judgment, the amount of any emissions that were the result of the malfunction.

(2) Report. The owner or operator seeking to assert an affirmative defense shall submit a written report to the Administrator with all necessary supporting documentation, that it has met the requirements set forth in paragraph (h)(1) of this section. This affirmative defense report shall be included in the first periodic compliance, deviation report or excess emission report otherwise required after the initial occurrence of the violation of the relevant standard (which may be the end of any applicable averaging period). If such compliance, deviation report or

excess emission report is due less than 45 days after the initial occurrence of the violation, the affirmative defense report may be included in the second compliance, deviation report or excess emission report due after the initial occurrence of the violation of the relevant standard.

§ 60.5416 What are the initial and continuous cover and closed vent system inspection and monitoring requirements for my storage vessel and centrifugal compressor affected facility?

For each closed vent system or cover at your storage vessel or centrifugal compressor affected facility, you must comply with the requirements of paragraphs (a) through (g) of this section.

(a) *Inspections.* Except as provided in paragraphs (e) and (f) of this section, you must inspect each closed vent system according to the procedures and schedule specified in paragraphs (a)(1) and (2) of this section, inspect each cover according to the procedures and schedule specified in paragraph (a)(3) of this section, and inspect each bypass device according to the procedures of paragraph (a)(4) of this section.

(1) For each closed vent system joint, seam, or other connection that is permanently or semi-permanently sealed (*e.g.,* a welded joint between two sections of hard piping or a bolted and gasketed ducting flange), you must meet the requirements specified in paragraphs (a)(1)(i) and (ii) of this section.

(i) Conduct an initial inspection according to the test methods and procedures specified in paragraph (b) of this section to demonstrate that the closed vent system operates with no detectable emissions. You must maintain records of the inspection results as specified in § 60.5420(c)(6).

(ii) Conduct annual visual inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in piping; loose connections; or broken or missing caps or other closure devices. You must monitor a component or connection using the test methods and procedures in paragraph (b) of this section to demonstrate that it operates with no detectable emissions following any time the component is repaired or replaced or the connection is unsealed. You must maintain records of the inspection results as specified in § 60.5420(c)(6).

(2) For closed vent system components other than those specified in paragraph (a)(1) of this section, you must meet the requirements of paragraphs (a)(2)(i) through (iii) of this section.

(i) Conduct an initial inspection according to the test methods and procedures specified in paragraph (b) of this section to demonstrate that the closed vent system operates with no detectable emissions. You must maintain records of the inspection results as specified in § 60.5420(c)(6).

(ii) Conduct annual inspections according to the test methods and procedures specified in paragraph (b) of this section to demonstrate that the components or connections operate with no detectable emissions. You must maintain records of the inspection results as specified in § 60.5420(c)(6).

(iii) Conduct annual visual inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in ductwork; loose connections; or broken or missing caps or other closure devices. You must maintain records of the inspection results as specified in § 60.5420(c)(6).

(3) For each cover, you must meet the requirements in paragraphs (a)(3)(i) and (ii) of this section.

(i) Conduct visual inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in the cover, or between the cover and the separator wall; broken, cracked, or otherwise damaged seals or gaskets on closure devices; and broken or missing hatches, access covers, caps, or other closure devices. In the case where the storage vessel is buried partially or entirely underground, you must inspect only those portions of the cover that extend to or above the ground surface, and those connections that are on such portions of the cover (*e.g.,* fill ports, access hatches, gauge wells, etc.) and can be opened to the atmosphere.

(ii) You must initially conduct the inspections specified in paragraph (a)(3)(i) of this section following the installation of the cover. Thereafter, you must perform the inspection at least once every calendar year, except as provided in paragraphs (e) and (f) of this section. You must maintain records of the inspection results as specified in § 60.5420(c)(7).

(4) For each bypass device, except as provided for in § 60.5411, you must meet the requirements of paragraphs (a)(4)(i) or (ii) of this section.

(i) Set the flow indicator to take a reading at least once every 15 minutes at the inlet to the bypass device that could divert the steam away from the control device to the atmosphere.

(ii) If the bypass device valve installed at the inlet to the bypass device is secured in the non-diverting position using a car-seal or a lock-and-key type configuration, visually inspect the seal or closure mechanism at least once every month to verify that the valve is maintained in the non-diverting position and the vent stream is not diverted through the bypass device. You must maintain records of the inspections according to § 60.5420(c)(8).

(b) *No detectable emissions test methods and procedures.* If you are required to conduct an inspection of a closed vent system or cover at your storage vessel or centrifugal compressor affected facility as specified in paragraphs (a)(1), (2), or (3) of this section, you must meet the requirements of paragraphs (b)(1) through (13) of this section.

(1) You must conduct the no detectable emissions test procedure in accordance with Method 21 at 40 CFR part 60, appendix A–7.

(2) The detection instrument must meet the performance criteria of Method 21 at 40 CFR part 60, appendix A–7, except that the instrument response factor criteria in section 3.1.2(a) of Method 21 must be for the average composition of the fluid and not for each individual organic compound in the stream.

(3) You must calibrate the detection instrument before use on each day of its use by the procedures specified in Method 21 at 40 CFR part 60, appendix A–7.

(4) Calibration gases must be as specified in paragraphs (b)(4)(i) and (ii) of this section.

(i) Zero air (less than 10 parts per million by volume hydrocarbon in air).

(ii) A mixture of methane in air at a concentration less than 10,000 parts per million by volume.

(5) You may choose to adjust or not adjust the detection instrument readings to account for the background organic concentration level. If you choose to adjust the instrument readings for the background level, you must determine the background level value according to the procedures in Method 21 at 40 CFR part 60, appendix A–7.

(6) Your detection instrument must meet the performance criteria specified in paragraphs (b)(6)(i) and (ii) of this section.

(i) Except as provided in paragraph (b)(6)(ii) of this section, the detection instrument must meet the performance criteria of Method 21 at 40 CFR part 60, appendix A–7, except the instrument response factor criteria in section 3.1.2(a) of Method 21 must be for the average composition of the process fluid, not each individual volatile organic compound in the stream. For

process streams that contain nitrogen, air, or other inerts that are not organic hazardous air pollutants or volatile organic compounds, you must calculate the average stream response factor on an inert-free basis.

(ii) If no instrument is available that will meet the performance criteria specified in paragraph (b)(6)(i) of this section, you may adjust the instrument readings by multiplying by the average response factor of the process fluid, calculated on an inert-free basis, as described in paragraph (b)(6)(i) of this section.

(7) You must determine if a potential leak interface operates with no detectable emissions using the applicable procedure specified in paragraph (b)(7)(i) or (ii) of this section.

(i) If you choose not to adjust the detection instrument readings for the background organic concentration level, then you must directly compare the maximum organic concentration value measured by the detection instrument to the applicable value for the potential leak interface as specified in paragraph (b)(8) of this section.

(ii) If you choose to adjust the detection instrument readings for the background organic concentration level, you must compare the value of the arithmetic difference between the maximum organic concentration value measured by the instrument and the background organic concentration value as determined in paragraph (b)(5) of this section with the applicable value for the potential leak interface as specified in paragraph (b)(8) of this section.

(8) A potential leak interface is determined to operate with no detectable organic emissions if the organic concentration value determined in paragraph (b)(7) of this section is less than 500 parts per million by volume.

(9) *Repairs.* In the event that a leak or defect is detected, you must repair the leak or defect as soon as practicable according to the requirements of paragraphs (b)(9)(i) and (ii) of this section, except as provided in paragraph (d) of this section.

(i) A first attempt at repair must be made no later than 5 calendar days after the leak is detected.

(ii) Repair must be completed no later than 15 calendar days after the leak is detected.

(10) *Delay of repair.* Delay of repair of a closed vent system or cover for which leaks or defects have been detected is allowed if the repair is technically infeasible without a shutdown, or if you determine that emissions resulting from immediate repair would be greater than the fugitive emissions likely to result from delay of repair. You must complete repair of such equipment by the end of the next shutdown.

(11) *Unsafe to inspect requirements.* You may designate any parts of the closed vent system or cover as unsafe to inspect if the requirements in paragraphs (e)(1) and (2) of this section are met. Unsafe to inspect parts are exempt from the inspection requirements of paragraphs (a)(1) through (3) of this section.

(A) You determine that the equipment is unsafe to inspect because inspecting personnel would be exposed to an imminent or potential danger as a consequence of complying with paragraphs (a)(1), (2), or (3) of this section.

(B) You have a written plan that requires inspection of the equipment as frequently as practicable during safe-to-inspect times.

(12) *Difficult to inspect requirements.* You may designate any parts of the closed vent system or cover as difficult to inspect, if the requirements in paragraphs (b)(12)(i) and (ii) of this section are met. Difficult to inspect parts are exempt from the inspection requirements of paragraphs (a)(1) through (3) of this section.

(i) You determine that the equipment cannot be inspected without elevating the inspecting personnel more than 2 meters above a support surface.

(ii) You have a written plan that requires inspection of the equipment at least once every 5 years.

(13) *Records.* Records shall be maintained as specified in this section and in § 60.5420(c)(9).

§ 60.5417 What are the continuous control device monitoring requirements for my storage vessel or centrifugal compressor affected facility?

You must meet the applicable requirements of this section to demonstrate continuous compliance for each control device used to meet emission standards for your storage vessel or centrifugal compressor affected facility.

(a) You must install and operate a continuous parameter monitoring system for each control device as specified in paragraphs (c) through (j) of this section, except as provided for in paragraph (b) of this section. If you install and operate a flare in accordance with § 60.5412(a)(3), you are exempt from the requirements of paragraphs (e) and (f) of this section.

(b) You are exempt from the monitoring requirements specified in paragraphs (c) through (j) of this section for the control devices listed in paragraphs (b)(1) and (2) of this section.

(1) A boiler or process heater in which all vent streams are introduced with the primary fuel or is used as the primary fuel.

(2) A boiler or process heater with a design heat input capacity equal to or greater than 44 megawatts.

(c) You must design and operate the continuous monitoring system so that a determination can be made on whether the control device is achieving the applicable performance requirements of § 60.5412. For each continuous parameter monitoring system, you must meet the specifications and requirements in paragraphs (c)(1) through (4) of this section.

(1) Each continuous parameter monitoring system must measure data values at least once every hour and record the parameters in paragraphs (c)(1)(i) or (ii) of this section.

(i) Each measured data value.

(ii) Each block average value for each 1-hour period or shorter periods calculated from all measured data values during each period. If values are measured more frequently than once per minute, a single value for each minute may be used to calculate the hourly (or shorter period) block average instead of all measured values.

(2) You must prepare a site-specific monitoring plan that addresses the monitoring system design, data collection, and the quality assurance and quality control elements outlined in paragraphs (c)(2)(i) through (v) of this section. You must install, calibrate, operate, and maintain each continuous parameter monitoring system in accordance with the procedures in your approved site-specific monitoring plan.

(i) The performance criteria and design specifications for the monitoring system equipment, including the sample interface, detector signal analyzer, and data acquisition and calculations.

(ii) Sampling interface (*e.g.,* thermocouple) location such that the monitoring system will provide representative measurements.

(iii) Equipment performance checks, system accuracy audits, or other audit procedures.

(iv) Ongoing operation and maintenance procedures in accordance with provisions in § 60.13(b).

(v) Ongoing reporting and recordkeeping procedures in accordance with provisions in § 60.7(c), (d), and (f).

(3) You must conduct the continuous parameter monitoring system equipment performance checks, system accuracy audits, or other audit procedures specified in the site-specific monitoring plan at least once every 12 months.

(4) You must conduct a performance evaluation of each continuous parameter monitoring system in

accordance with the site-specific monitoring plan.

(d) You must install, calibrate, operate, and maintain a device equipped with a continuous recorder to measure the values of operating parameters appropriate for the control device as specified in either paragraph (d)(1), (2), or (3) of this section.

(1) A continuous monitoring system that measures the operating parameters in paragraphs (d)(1)(i) through (viii) of this section, as applicable.

(i) For a thermal vapor incinerator that demonstrates during the performance test conducted under § 60.5413 that combustion zone temperature is an accurate indicator of performance, a temperature monitoring device equipped with a continuous recorder. The monitoring device must have a minimum accuracy of ±1 percent of the temperature being monitored in °C, or ±2.5 °C, whichever value is greater. You must install the temperature sensor at a location representative of the combustion zone temperature.

(ii) For a catalytic vapor incinerator, a temperature monitoring device equipped with a continuous recorder. The device must be capable of monitoring temperature at two locations and have a minimum accuracy of ±1 percent of the temperature being monitored in °C, or ±2.5 °C, whichever value is greater. You must install one temperature sensor in the vent stream at the nearest feasible point to the catalyst bed inlet, and you must install a second temperature sensor in the vent stream at the nearest feasible point to the catalyst bed outlet.

(iii) For a flare, a heat sensing monitoring device equipped with a continuous recorder that indicates the continuous ignition of the pilot flame.

(iv) For a boiler or process heater, a temperature monitoring device equipped with a continuous recorder. The temperature monitoring device must have a minimum accuracy of ±1 percent of the temperature being monitored in °C, or ±2.5 °C, whichever value is greater. You must install the temperature sensor at a location representative of the combustion zone temperature.

(v) For a condenser, a temperature monitoring device equipped with a continuous recorder. The temperature monitoring device must have a minimum accuracy of ±1 percent of the temperature being monitored in °C, or ±2.8 °C, whichever value is greater. You must install the temperature sensor at a location in the exhaust vent stream from the condenser.

(vi) For a regenerative-type carbon adsorption system, a continuous monitoring system that meets the specifications in paragraphs (d)(1)(vi)(A) and (B) of this section.

(A) The continuous parameter monitoring system must measure and record the average total regeneration stream mass flow or volumetric flow during each carbon bed regeneration cycle. The flow sensor must have a measurement sensitivity of 5 percent of the flow rate or 10 cubic feet per minute, whichever is greater. You must check the mechanical connections for leakage at least every month, and you must perform a visual inspection at least every 3 months of all components of the flow continuous parameter monitoring system for physical and operational integrity and all electrical connections for oxidation and galvanic corrosion if your flow continuous parameter monitoring system is not equipped with a redundant flow sensor; and

(B) The continuous parameter monitoring system must measure and record the average carbon bed temperature for the duration of the carbon bed steaming cycle and measure the actual carbon bed temperature after regeneration and within 15 minutes of completing the cooling cycle. The temperature monitoring device must have a minimum accuracy of ±1 percent of the temperature being monitored in °C, or ±2.5 °C, whichever value is greater.

(vii) For a nonregenerative-type carbon adsorption system, you must monitor the design carbon replacement interval established using a performance test performed as specified in § 60.5413(b). The design carbon replacement interval must be based on the total carbon working capacity of the control device and source operating schedule.

(viii) For a combustion control device whose model is tested under § 60.5413(d), a continuous monitoring system meeting the requirements of paragraphs (d)(1)(viii)(A) and (B) of this section.

(A) The continuous monitoring system must measure gas flow rate at the inlet to the control device. The monitoring instrument must have an accuracy of ±2 percent or better.

(B) A heat sensing monitoring device equipped with a continuous recorder that indicates the continuous ignition of the pilot flame.

(2) A continuous monitoring system that measures the concentration level of organic compounds in the exhaust vent stream from the control device using an organic monitoring device equipped with a continuous recorder. The monitor must meet the requirements of Performance Specification 8 or 9 of 40 CFR part 60, appendix B. You must install, calibrate, and maintain the monitor according to the manufacturer's specifications.

(3) A continuous monitoring system that measures operating parameters other than those specified in paragraph (d)(1) or (2) of this section, upon approval of the Administrator as specified in § 60.13(i).

(e) You must calculate the daily average value for each monitored operating parameter for each operating day, using the data recorded by the monitoring system, except for inlet gas flow rate. If the emissions unit operation is continuous, the operating day is a 24-hour period. If the emissions unit operation is not continuous, the operating day is the total number of hours of control device operation per 24-hour period. Valid data points must be available for 75 percent of the operating hours in an operating day to compute the daily average.

(f) For each operating parameter monitor installed in accordance with the requirements of paragraph (d) of this section, you must comply with paragraph (f)(1) of this section for all control devices. When condensers are installed, you must also comply with paragraph (f)(2) of this section.

(1) You must establish a minimum operating parameter value or a maximum operating parameter value, as appropriate for the control device, to define the conditions at which the control device must be operated to continuously achieve the applicable performance requirements of § 60.5412(a). You must establish each minimum or maximum operating parameter value as specified in paragraphs (f)(1)(i) through (iii) of this section.

(i) If you conduct performance tests in accordance with the requirements of § 60.5413(b) to demonstrate that the control device achieves the applicable performance requirements specified in § 60.5412(a), then you must establish the minimum operating parameter value or the maximum operating parameter value based on values measured during the performance test and supplemented, as necessary, by a condenser design analysis or control device manufacturer recommendations or a combination of both.

(ii) If you use a condenser design analysis in accordance with the requirements of § 60.5413(c) to demonstrate that the control device achieves the applicable performance requirements specified in § 60.5412(a), then you must establish the minimum

operating parameter value or the maximum operating parameter value based on the condenser design analysis and supplemented, as necessary, by the condenser manufacturer's recommendations.

(iii) If you operate a control device where the performance test requirement was met under § 60.5413(d) to demonstrate that the control device achieves the applicable performance requirements specified in § 60.5412(a), then you must establish the maximum inlet gas flow rate based on the performance test and supplemented, as necessary, by the manufacturer recommendations.

(2) If you use a condenser as specified in paragraph (d)(1)(v) of this section, you must establish a condenser performance curve showing the relationship between condenser outlet temperature and condenser control efficiency, according to the requirements of paragraphs (f)(2)(i) and (ii) of this section.

(i) If you conduct a performance test in accordance with the requirements of § 60.5413(b) to demonstrate that the condenser achieves the applicable performance requirements in § 60.5412(a), then the condenser performance curve must be based on values measured during the performance test and supplemented as necessary by control device design analysis, or control device manufacturer's recommendations, or a combination or both.

(ii) If you use a control device design analysis in accordance with the requirements of § 60.5413(c)(1) to demonstrate that the condenser achieves the applicable performance requirements specified in § 60.5412(a), then the condenser performance curve must be based on the condenser design analysis and supplemented, as necessary, by the control device manufacturer's recommendations.

(g) A deviation for a given control device is determined to have occurred when the monitoring data or lack of monitoring data result in any one of the criteria specified in paragraphs (g)(1) through (g)(6) of this section being met. If you monitor multiple operating parameters for the same control device during the same operating day and more than one of these operating parameters meets a deviation criterion specified in paragraphs (g)(1) through (6) of this section, then a single excursion is determined to have occurred for the control device for that operating day.

(1) A deviation occurs when the daily average value of a monitored operating parameter is less than the minimum operating parameter limit (or, if applicable, greater than the maximum operating parameter limit) established in paragraph (f)(1) of this section.

(2) If you meet § 60.5412(a)(2), a deviation occurs when the 365-day average condenser efficiency calculated according to the requirements specified in § 60.5415(e)(8)(iv) is less than 95.0 percent.

(3) If you meet § 60.5412(a)(2) and you have less than 365 days of data, a deviation occurs when the average condenser efficiency calculated according to the procedures specified in § 60.5415(e)(8)(iv)(A) or (B) is less than 90.0 percent.

(4) A deviation occurs when the monitoring data are not available for at least 75 percent of the operating hours in a day.

(5) If the closed vent system contains one or more bypass devices that could be used to divert all or a portion of the gases, vapors, or fumes from entering the control device, a deviation occurs when the requirements of paragraphs (g)(5)(i) and (ii) of this section are met.

(i) For each bypass line subject to § 60.5411(a)(3)(i)(A), the flow indicator indicates that flow has been detected and that the stream has been diverted away from the control device to the atmosphere.

(ii) For each bypass line subject to § 60.5411(a)(3)(i)(B), if the seal or closure mechanism has been broken, the bypass line valve position has changed, the key for the lock-and-key type lock has been checked out, or the car-seal has broken.

(6) For a combustion control device whose model is tested under § 60.5413(d), a deviation occurs when the conditions of paragraphs (g)(6)(i) or (ii) are met.

(i) The inlet gas flow rate exceeds the maximum established during the test conducted under § 60.5413(d).

(ii) Failure of the monthly visible emissions test conducted under § 60.5415(e)(7)(iii) occurs.

§ 60.5420 What are my notification, reporting, and recordkeeping requirements?

(a) You must submit the notifications required in § 60.7(a)(1) and (4), and according to paragraphs (a)(1) and (2) of this section, if you own or operate one or more of the affected facilities specified in § 60.5365 that was constructed, modified, or reconstructed during the reporting period.

(1) If you own or operate a gas well, pneumatic controller or storage vessel affected facility you are not required to submit the notifications required in § 60.7(a)(1), (3), and (4).

(2)(i) If you own or operate a gas well affected facility, you must submit a notification to the Administrator no later than 2 days prior to the commencement of each well completion operation listing the anticipated date of the well completion operation. The notification shall include contact information for the owner or operator; the API well number, the latitude and longitude coordinates for each well in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983; and the planned date of the beginning of flowback. You may submit the notification in writing or in electronic format.

(ii) If you are subject to state regulations that require advance notification of well completions and you have met those notification requirements, then you are considered to have met the advance notification requirements of paragraph (a)(2)(i) of this section.

(b) *Reporting requirements.* You must submit annual reports containing the information specified in paragraphs (b)(1) through (6) of this section to the Administrator and performance test reports as specified in paragraph (b)(7) of this section. The initial annual report is due 30 days after the end of the initial compliance period as determined according to § 60.5410. Subsequent annual reports are due on the same date each year as the initial annual report. If you own or operate more than one affected facility, you may submit one report for multiple affected facilities provided the report contains all of the information required as specified in paragraphs (b)(1) through (6) of this section. Annual reports may coincide with title V reports as long as all the required elements of the annual report are included. You may arrange with the Administrator a common schedule on which reports required by this part may be submitted as long as the schedule does not extend the reporting period.

(1) The general information specified in paragraphs (b)(1)(i) through (iv) of this section.

(i) The company name and address of the affected facility.

(ii) An identification of each affected facility being included in the annual report.

(iii) Beginning and ending dates of the reporting period.

(iv) A certification by a responsible official of truth, accuracy, and completeness. This certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

(2) For each gas well affected facility, the information in paragraphs (b)(2)(i) through (ii) of this section.

(i) Records of each well completion operation as specified in paragraph (c)(1)(i) through (iv) of this section for each gas well affected facility conducted during the reporting period. In lieu of submitting the records specified in paragraph (c)(1)(i) through (iv), the owner or operator may submit a list of the well completions with hydraulic fracturing completed during the reporting period and the records required by paragraph (c)(1)(v) of this section for each well completion.

(ii) Records of deviations specified in paragraph (c)(1)(ii) of this section that occurred during the reporting period.

(3) For each centrifugal compressor affected facility, the information specified in paragraphs (b)(3)(i) and (ii) of this section.

(i) An identification of each centrifugal compressor using a wet seal system constructed, modified or reconstructed during the reporting period.

(ii) Records of deviations specified in paragraph (c)(2) of this section that occurred during the reporting period.

(iii) If required to comply with § 60.5380(a)(1), the records of closed vent system and cover inspections specified in paragraph (c)(6) of this section.

(4) For each reciprocating compressor affected facility, the information specified in paragraphs (b)(4)(i) through (ii) of this section.

(i) The cumulative number of hours or operation or the number of months since initial startup, October 15, 2012, or since the previous reciprocating compressor rod packing replacement, whichever is later.

(ii) Records of deviations specified in paragraph (c)(3)(iii) of this section that occurred during the reporting period.

(5) For each pneumatic controller affected facility, the information specified in paragraphs (b)(5)(i) through (v) of this section.

(i) An identification of each pneumatic controller constructed, modified or reconstructed during the reporting period, including the identification information specified in § 60.5390(c)(2).

(ii) If applicable, documentation that the use of pneumatic controller affected facilities with a natural gas bleed rate greater than 6 standard cubic feet per hour are required and the reasons why.

(iii) Records of deviations specified in paragraph (c)(4)(v) of this section that occurred during the reporting period.

(6) For each storage vessel affected facility, the information in paragraphs (b)(6)(i) through (iii) of this section.

(i) An identification of each storage vessel with VOC emissions greater than 6 tpy constructed, modified or reconstructed during the reporting period.

(ii) Documentation that the VOC emission rate is less than 6 tpy for meeting the requirements in § 60.5395(a).

(iii) Records of deviations specified in paragraph (c)(5)(iii) of this section that occurred during the reporting period.

(7)(i) Within 60 days after the date of completing each performance test (see § 60.8 of this part) as required by this subpart you must submit the results of the performance tests required by this subpart to EPA's WebFIRE database by using the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (*www.epa.gov/cdx*). Performance test data must be submitted in the file format generated through use of EPA's Electronic Reporting Tool (ERT) (see *http://www.epa.gov/ttn/chief/ert/index.html*). Only data collected using test methods on the ERT Web site are subject to this requirement for submitting reports electronically to WebFIRE. Owners or operators who claim that some of the information being submitted for performance tests is confidential business information (CBI) must submit a complete ERT file including information claimed to be CBI on a compact disk or other commonly used electronic storage media (including, but not limited to, flash drives) to EPA. The electronic media must be clearly marked as CBI and mailed to U.S. EPA/OAPQS/CORE CBI Office, Attention: WebFIRE Administrator, MD C404–02, 4930 Old Page Rd., Durham, NC 27703. The same ERT file with the CBI omitted must be submitted to EPA via CDX as described earlier in this paragraph. At the discretion of the delegated authority, you must also submit these reports, including the confidential business information, to the delegated authority in the format specified by the delegated authority.

(ii) All reports required by this subpart not subject to the requirements in paragraph (a)(2)(i) of this section must be sent to the Administrator at the appropriate address listed in § 63.13 of this part. The Administrator or the delegated authority may request a report in any form suitable for the specific case (*e.g.,* by commonly used electronic media such as Excel spreadsheet, on CD or hard copy). The Administrator retains the right to require submittal of reports subject to paragraph (a)(2)(i) and (ii) of this section in paper format.

(c) *Recordkeeping requirements.* You must maintain the records identified as specified in § 60.7(f) and in paragraphs (c)(1) through (10) of this section. All records must be maintained for at least 5 years.

(1) The records for each gas well affected facility as specified in paragraphs (c)(1)(i) through (v) of this section.

(i) Records identifying each well completion operation for each gas well affected facility;

(ii) Records of deviations in cases where well completion operations with hydraulic fracturing were not performed in compliance with the requirements specified in § 60.5375.

(iii) Records required in § 60.5375(b) or (f) for each well completion operation conducted for each gas well affected facility that occurred during the reporting period. You must maintain the records specified in paragraphs (c)(1)(iii)(A) and (B) of this section.

(A) For each gas well affected facility required to comply with the requirements of § 60.5375(a), you must record: The location of the well; the API well number; the duration of flowback; duration of recovery to the flow line; duration of combustion; duration of venting; and specific reasons for venting in lieu of capture or combustion. The duration must be specified in hours of time.

(B) For each gas well affected facility required to comply with the requirements of § 60.5375(f), you must maintain the records specified in paragraph (c)(1)(iii)(A) of this section except that you do not have to record the duration of recovery to the flow line.

(iv) For each gas well facility for which you claim an exception under § 60.5375(a)(3), you must record: The location of the well; the API well number; the specific exception claimed; the starting date and ending date for the period the well operated under the exception; and an explanation of why the well meets the claimed exception.

(v) For each gas well affected facility required to comply with both § 60.5375(a)(1) and (3), records of the digital photograph as specified in § 60.5410(a)(4).

(2) For each centrifugal compressor affected facility, you must maintain records of deviations in cases where the centrifugal compressor was not operated in compliance with the requirements specified in § 60.5380.

(3) For each reciprocating compressors affected facility, you must maintain the records in paragraphs (c)(3)(i) through (iii) of this section.

(i) Records of the cumulative number of hours of operation or number of months since initial startup or October 15, 2012, or the previous replacement of the reciprocating compressor rod packing, whichever is later.

(ii) Records of the date and time of each reciprocating compressor rod packing replacement.

(iii) Records of deviations in cases where the reciprocating compressor was not operated in compliance with the requirements specified in § 60.5385.

(4) For each pneumatic controller affected facility, you must maintain the records identified in paragraphs (c)(4)(i) through (v) of this section.

(i) Records of the date, location and manufacturer specifications for each pneumatic controller constructed, modified or reconstructed.

(ii) Records of the demonstration that the use of pneumatic controller affected facilities with a natural gas bleed rate greater than 6 standard cubic feet per hour are required and the reasons why.

(iii) If the pneumatic controller is not located at a natural gas processing plant, records of the manufacturer's specifications indicating that the controller is designed such that natural gas bleed rate is less than or equal to 6 standard cubic feet per hour.

(iv) If the pneumatic controller is located at a natural gas processing plant, records of the documentation that the natural gas bleed rate is zero.

(v) Records of deviations in cases where the pneumatic controller was not operated in compliance with the requirements specified in § 60.5390.

(5) For each storage vessel affected facility, you must maintain the records identified in paragraphs (c)(5)(i) through (iv) of this section.

(i) If required to reduce emissions by complying with § 60.5395, the records specified in § 60.5416 of this subpart.

(ii) Records of the determination that the VOC emission rate is less than 6 tpy per storage vessel for the exemption under § 60.5395(a), including identification of the model or calculation methodology used to calculate the VOC emission rate.

(iii) Records of deviations in cases where the storage vessel was not operated in compliance with the requirements specified in §§ 60.5395, 60.5411, 60.5412, and 60.5413.

(iv) For vessels that are skid-mounted or permanently attached to something that is mobile (such as trucks, railcars, barges or ships), records indicating the number of consecutive days that the vessel is located at a site in the oil and natural gas production segment, natural gas processing segment or natural gas transmission and storage segment. If a vessel is removed from a site and, within 30 days, is either returned to or replaced by another vessel at the site to serve the same or similar function, then the entire period since the original vessel was first located at the site, including the days when the storage vessel was removed, will be added to the count towards the number of consecutive days.

(6) For each storage vessel or centrifugal compressor subject to the closed vent system inspection requirements of § 60.5416(a)(1) and (2), records of each inspection.

(7) For each storage vessel or centrifugal compressor subject to the cover requirements of § 60.5416(a)(3), a record of each inspection.

(8) For each storage vessel or centrifugal compressor subject to the bypass requirements of § 60.5416(a)(4), a record of each inspection or a record each time the key is checked out or a record of each time the alarm is sounded.

(9) For each closed vent system used to comply with this subpart that must operate with no detectable emissions, a record of the monitoring conducted in accordance with § 60.5416(b)(13).

(10) Records of the schedule for carbon replacement (as determined by the design analysis requirements of § 60.5413(c)(2) or (3)) and records of each carbon replacement as specified in § 60.5412(c)(1).

(11) For each storage vessel or centrifugal compressor subject to the control device requirements of § 60.5412, records of minimum and maximum operating parameter values, continuous parameter monitoring system data, calculated averages of continuous parameter monitoring system data, results of all compliance calculations, and results of all inspections.

§ 60.5421 What are my additional recordkeeping requirements for my affected facility subject to VOC requirements for onshore natural gas processing plants?

(a) You must comply with the requirements of paragraph (b) of this section in addition to the requirements of § 60.486a.

(b) The following recordkeeping requirements apply to pressure relief devices subject to the requirements of § 60.5401(b)(1) of this subpart.

(1) When each leak is detected as specified in § 60.5401(b)(2), a weatherproof and readily visible identification, marked with the equipment identification number, must be attached to the leaking equipment. The identification on the pressure relief device may be removed after it has been repaired.

(2) When each leak is detected as specified in § 60.5401(b)(2), the following information must be recorded in a log and shall be kept for 2 years in a readily accessible location:

(i) The instrument and operator identification numbers and the equipment identification number.

(ii) The date the leak was detected and the dates of each attempt to repair the leak.

(iii) Repair methods applied in each attempt to repair the leak.

(iv) "Above 500 ppm" if the maximum instrument reading measured by the methods specified in paragraph (a) of this section after each repair attempt is 500 ppm or greater.

(v) "Repair delayed" and the reason for the delay if a leak is not repaired within 15 calendar days after discovery of the leak.

(vi) The signature of the owner or operator (or designate) whose decision it was that repair could not be effected without a process shutdown.

(vii) The expected date of successful repair of the leak if a leak is not repaired within 15 days.

(viii) Dates of process unit shutdowns that occur while the equipment is unrepaired.

(ix) The date of successful repair of the leak.

(x) A list of identification numbers for equipment that are designated for no detectable emissions under the provisions of § 60.482–4a(a). The designation of equipment subject to the provisions of § 60.482–4a(a) must be signed by the owner or operator.

§ 60.5422 What are my additional reporting requirements for my affected facility subject to VOC requirements for onshore natural gas processing plants?

(a) You must comply with the requirements of paragraphs (b) and (c) of this section in addition to the requirements of § 60.487a(a), (b), (c)(2)(i) through (iv), and (c)(2)(vii) through (viii).

(b) An owner or operator must include the following information in the initial semiannual report in addition to the information required in § 60.487a(b)(1) through (4): Number of pressure relief devices subject to the requirements of § 60.5401(b) except for those pressure relief devices designated for no detectable emissions under the provisions of § 60.482–4a(a) and those pressure relief devices complying with § 60.482–4a(c).

(c) An owner or operator must include the following information in all semiannual reports in addition to the information required in § 60.487a(c)(2)(i) through (vi):

(1) Number of pressure relief devices for which leaks were detected as required in § 60.5401(b)(2); and

(2) Number of pressure relief devices for which leaks were not repaired as required in § 60.5401(b)(3).

§ 60.5423 What additional recordkeeping and reporting requirements apply to my sweetening unit affected facilities at onshore natural gas processing plants?

(a) You must retain records of the calculations and measurements required in § 60.5405(a) and (b) and § 60.5407(a) through (g) for at least 2 years following the date of the measurements. This requirement is included under § 60.7(d) of the General Provisions.

(b) You must submit a report of excess emissions to the Administrator in your annual report if you had excess emissions during the reporting period. For the purpose of these reports, excess emissions are defined as:

(1) Any 24-hour period (at consistent intervals) during which the average sulfur emission reduction efficiency (R) is less than the minimum required efficiency (Z).

(2) For any affected facility electing to comply with the provisions of § 60.5407(b)(2), any 24-hour period during which the average temperature of the gases leaving the combustion zone of an incinerator is less than the appropriate operating temperature as determined during the most recent performance test in accordance with the provisions of § 60.5407(b)(2). Each 24-hour period must consist of at least 96 temperature measurements equally spaced over the 24 hours.

(c) To certify that a facility is exempt from the control requirements of these standards, for each facility with a design capacity less that 2 LT/D of H_2S in the acid gas (expressed as sulfur) you must keep, for the life of the facility, an analysis demonstrating that the facility's design capacity is less than 2 LT/D of H_2S expressed as sulfur.

(d) If you elect to comply with § 60.5407(e) you must keep, for the life of the facility, a record demonstrating that the facility's design capacity is less than 150 LT/D of H_2S expressed as sulfur.

(e) The requirements of paragraph (b) of this section remain in force until and unless the EPA, in delegating enforcement authority to a state under section 111(c) of the Act, approves reporting requirements or an alternative means of compliance surveillance adopted by such state. In that event, affected sources within the state will be relieved of obligation to comply with paragraph (b) of this section, provided that they comply with the requirements established by the state.

§ 60.5425 What part of the General Provisions apply to me?

Table 3 to this subpart shows which parts of the General Provisions in §§ 60.1 through 60.19 apply to you.

§ 60.5430 What definitions apply to this subpart?

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act, in subpart A or subpart VVa of part 60; and the following terms shall have the specific meanings given them.

Acid gas means a gas stream of hydrogen sulfide (H_2S) and carbon dioxide (CO_2) that has been separated from sour natural gas by a sweetening unit.

Affirmative defense means, in the context of an enforcement proceeding, a response or defense put forward by a defendant, regarding which the defendant has the burden of proof, and the merits of which are independently and objectively evaluated in a judicial or administrative proceeding.

Alaskan North Slope means the approximately 69,000 square-mile area extending from the Brooks Range to the Arctic Ocean.

API Gravity means the weight per unit volume of hydrocarbon liquids as measured by a system recommended by the American Petroleum Institute (API) and is expressed in degrees.

Bleed rate means the rate in standard cubic feet per hour at which natural gas is continuously vented (bleeds) from a pneumatic controller.

Centrifugal compressor means any machine for raising the pressure of a natural gas by drawing in low pressure natural gas and discharging significantly higher pressure natural gas by means of mechanical rotating vanes or impellers. Screw, sliding vane, and liquid ring compressors are not centrifugal compressors for the purposes of this subpart.

City gate means the delivery point at which natural gas is transferred from a transmission pipeline to the local gas utility.

Completion combustion device means any ignition device, installed horizontally or vertically, used in exploration and production operations to combust otherwise vented emissions from completions.

Compressor station means any permanent combination of one or more compressors that move natural gas at increased pressure from fields, in transmission pipelines, or into storage.

Continuous bleed means a continuous flow of pneumatic supply natural gas to the process control device (*e.g.,* level control, temperature control, pressure control) where the supply gas pressure is modulated by the process condition, and then flows to the valve controller where the signal is compared with the process set-point to adjust gas pressure in the valve actuator.

Custody transfer means the transfer of natural gas after processing and/or treatment in the producing operations, or from storage vessels or automatic transfer facilities or other such equipment, including product loading racks, to pipelines or any other forms of transportation.

Dehydrator means a device in which an absorbent directly contacts a natural gas stream and absorbs water in a contact tower or absorption column (absorber).

Deviation means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:

(1) Fails to meet any requirement or obligation established by this subpart including, but not limited to, any emission limit, operating limit, or work practice standard;

(2) Fails to meet any term or condition that is adopted to implement an applicable requirement in this subpart and that is included in the operating permit for any affected source required to obtain such a permit; or

(3) Fails to meet any emission limit, operating limit, or work practice standard in this subpart during startup, shutdown, or malfunction, regardless of whether or not such failure is permitted by this subpart.

Delineation well means a well drilled in order to determine the boundary of a field or producing reservoir.

Equipment means each pump, pressure relief device, open-ended valve or line, valve, and flange or other connector that is in VOC service or in wet gas service, and any device or system required by this subpart.

Field gas means feedstock gas entering the natural gas processing plant.

Field gas gathering means the system used transport field gas from a field to the main pipeline in the area.

Flare means a thermal oxidation system using an open (without enclosure) flame. Completion combustion devices as defined in this section are not considered flares.

Flow line means a pipeline used to transport oil and/or gas from the well to a processing facility, a mainline pipeline, re-injection, or other useful purpose.

Flowback means the process of allowing fluids to flow from a natural

gas well following a treatment, either in preparation for a subsequent phase of treatment or in preparation for cleanup and returning the well to production. The flowback period begins when material introduced into the well during the treatment returns to the surface immediately following hydraulic fracturing or refracturing. The flowback period ends with either well shut in or when the well is producing continuously to the flow line or to a storage vessel for collection, whichever occurs first.

Gas processing plant process unit means equipment assembled for the extraction of natural gas liquids from field gas, the fractionation of the liquids into natural gas products, or other operations associated with the processing of natural gas products. A process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the products.

Gas well or natural gas well means an onshore well drilled principally for production of natural gas.

Hydraulic fracturing or refracturing means the process of directing pressurized fluids containing any combination of water, proppant, and any added chemicals to penetrate tight formations, such as shale or coal formations, that subsequently require high rate, extended flowback to expel fracture fluids and solids during completions.

Hydraulic refracturing means conducting a subsequent hydraulic fracturing operation at a well that has previously undergone a hydraulic fracturing operation.

In light liquid service means that the piece of equipment contains a liquid that meets the conditions specified in § 60.485a(e) or § 60.5401(g)(2) of this part.

In wet gas service means that a compressor or piece of equipment contains or contacts the field gas before the extraction step at a gas processing plant process unit.

Intermittent/snap-action pneumatic controller means a pneumatic controller that vents non-continuously.

Liquefied natural gas unit means a unit used to cool natural gas to the point at which it is condensed into a liquid which is colorless, odorless, non-corrosive and non-toxic.

Low pressure gas well means a well with reservoir pressure and vertical well depth such that 0.445 times the reservoir pressure (in psia) minus 0.038 times the vertical well depth (in feet) minus 67.578 psia is less than the flow line pressure at the sales meter.

Natural gas-driven pneumatic controller means a pneumatic controller powered by pressurized natural gas.

Natural gas liquids means the hydrocarbons, such as ethane, propane, butane, and pentane that are extracted from field gas.

Natural gas processing plant (gas plant) means any processing site engaged in the extraction of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both. A Joule-Thompson valve, a dew point depression valve, or an isolated or standalone Joule-Thompson skid is not a natural gas processing plant.

Natural gas transmission means the pipelines used for the long distance transport of natural gas (excluding processing). Specific equipment used in natural gas transmission includes the land, mains, valves, meters, boosters, regulators, storage vessels, dehydrators, compressors, and their driving units and appurtenances, and equipment used for transporting gas from a production plant, delivery point of purchased gas, gathering system, storage area, or other wholesale source of gas to one or more distribution area(s).

Nonfractionating plant means any gas plant that does not fractionate mixed natural gas liquids into natural gas products.

Non-natural gas-driven pneumatic controller means an instrument that is actuated using other sources of power than pressurized natural gas; examples include solar, electric, and instrument air.

Onshore means all facilities except those that are located in the territorial seas or on the outer continental shelf.

Pneumatic controller means an automated instrument used for maintaining a process condition such as liquid level, pressure, delta-pressure and temperature.

Pressure vessel means a storage vessel that is used to store liquids or gases and is designed not to vent to the atmosphere as a result of compression of the vapor headspace in the pressure vessel during filling of the pressure vessel to its design capacity.

Process unit means components assembled for the extraction of natural gas liquids from field gas, the fractionation of the liquids into natural gas products, or other operations associated with the processing of natural gas products. A process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the products.

Reciprocating compressor means a piece of equipment that increases the pressure of a process gas by positive displacement, employing linear movement of the driveshaft.

Reciprocating compressor rod packing means a series of flexible rings in machined metal cups that fit around the reciprocating compressor piston rod to create a seal limiting the amount of compressed natural gas that escapes to the atmosphere.

Reduced emissions completion means a well completion following fracturing or refracturing where gas flowback that is otherwise vented is captured, cleaned, and routed to the flow line or collection system, re-injected into the well or another well, used as an on-site fuel source, or used for other useful purpose that a purchased fuel or raw material would serve, with no direct release to the atmosphere.

Reduced sulfur compounds means H_2S, carbonyl sulfide (COS), and carbon disulfide (CS_2).

Responsible official means one of the following:

(1) For a corporation: A president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit and either:

(i) The facilities employ more than 250 persons or have gross annual sales or expenditures exceeding $25 million (in second quarter 1980 dollars); or

(ii) The delegation of authority to such representatives is approved in advance by the permitting authority;

(2) For a partnership or sole proprietorship: A general partner or the proprietor, respectively;

(3) For a municipality, State, Federal, or other public agency: Either a principal executive officer or ranking elected official. For the purposes of this part, a principal executive officer of a Federal agency includes the chief executive officer having responsibility for the overall operations of a principal geographic unit of the agency (*e.g.,* a Regional Administrator of EPA); or

(4) For affected facilities:

(i) The designated representative in so far as actions, standards, requirements, or prohibitions under title IV of the Clean Air Act or the regulations promulgated thereunder are concerned; or

(ii) The designated representative for any other purposes under part 60.

Routed to a process or route to a process means the emissions are conveyed via a closed vent system to any enclosed portion of a process unit where the emissions are predominantly recycled and/or consumed in the same manner as a material that fulfills the same function in the process and/or transformed by chemical reaction into materials that are not regulated materials and/or incorporated into a product; and/or recovered.

Salable quality gas means natural gas that meets the composition, moisture, or other limits set by the purchaser of the natural gas, regardless of whether such gas is sold.

Storage vessel means a unit that is constructed primarily of nonearthen materials (such as wood, concrete, steel, fiberglass, or plastic) which provides structural support and is designed to contain an accumulation of liquids or other materials. The following are not considered storage vessels:

(1) Vessels that are skid-mounted or permanently attached to something that is mobile (such as trucks, railcars, barges or ships), and are intended to be located at a site for less than 180 consecutive days. If you do not keep or are not able to produce records, as required by § 60.5420(c)(5)(iv), showing that the vessel has been located at a site for less than 180 consecutive days, the vessel described herein is considered to be a storage vessel since the original vessel was first located at the site.

(2) Process vessels such as surge control vessels, bottoms receivers or knockout vessels.

(3) Pressure vessels designed to operate in excess of 204.9 kilopascals and without emissions to the atmosphere.

Sulfur production rate means the rate of liquid sulfur accumulation from the sulfur recovery unit.

Sulfur recovery unit means a process device that recovers element sulfur from acid gas.

Surface site means any combination of one or more graded pad sites, gravel pad sites, foundations, platforms, or the immediate physical location upon which equipment is physically affixed.

Sweetening unit means a process device that removes hydrogen sulfide and/or carbon dioxide from the sour natural gas stream.

Total Reduced Sulfur (TRS) means the sum of the sulfur compounds hydrogen sulfide, methyl mercaptan, dimethyl sulfide, and dimethyl disulfide as measured by Method 16 of appendix A to part 60 of this chapter.

Total SO2 equivalents means the sum of volumetric or mass concentrations of the sulfur compounds obtained by adding the quantity existing as SO_2 to the quantity of SO_2 that would be obtained if all reduced sulfur compounds were converted to SO_2 (ppmv or kg/dscm (lb/dscf)).

Underground storage vessel means a storage vessel stored below ground.

Well means an oil or gas well, a hole drilled for the purpose of producing oil or gas, or a well into which fluids are injected.

Well completion means the process that allows for the flowback of petroleum or natural gas from newly drilled wells to expel drilling and reservoir fluids and tests the reservoir flow characteristics, which may vent produced hydrocarbons to the atmosphere via an open pit or tank.

Well completion operation means any well completion with hydraulic fracturing or refracturing occurring at a gas well affected facility.

Well site means one or more areas that are directly disturbed during the drilling and subsequent operation of, or affected by, production facilities directly associated with any oil well, gas well, or injection well and its associated well pad.

Wellhead means the piping, casing, tubing and connected valves protruding above the earth's surface for an oil and/or natural gas well. The wellhead ends where the flow line connects to a wellhead valve. The wellhead does not include other equipment at the well site except for any conveyance through which gas is vented to the atmosphere.

Wildcat well means a well outside known fields or the first well drilled in an oil or gas field where no other oil and gas production exists.

TABLE 1 TO SUBPART OOOO OF PART 60—REQUIRED MINIMUM INITIAL SO_2 EMISSION REDUCTION EFFICIENCY (Z_i)

H_2S content of acid gas (Y), %	Sulfur feed rate (X), LT/D			
	$2.0 \leq X \leq 5.0$	$5.0 < X \leq 15.0$	$15.0 < X \leq 300.0$	$X > 300.0$
$Y \geq 50$	79.0	$88.51X^{0.0101}Y^{0.0125}$ or 99.9, whichever is smaller.		
$20 \leq Y < 50$	79.0	$88.5X^{0.0101}Y^{0.0125}$ or 97.9, whichever is smaller.		97.9
$10 \leq Y < 20$	79.0	$88.5X^{0.0101}Y^{0.0125}$ or 97.9, whichever is smaller.	93.5	93.5
$Y < 10$	79.0	79.0	79.0	79.0

TABLE 2 TO SUBPART OOOO OF PART 60—REQUIRED MINIMUM SO_2 EMISSION REDUCTION EFFICIENCY (Z_c)

H_2S content of acid gas (Y), %	Sulfur feed rate (X), LT/D			
	$2.0 \leq X \leq 5.0$	$5.0 < X \leq 15.0$	$15.0 < X \leq 300.0$	$X > 300.0$
$Y \geq 50$	74.0	$85.35X^{0.0144}Y^{0.0128}$ or 99.9, whichever is smaller.		
$20 \leq Y < 50$	74.0	$85.35X^{0.0144}Y^{0.0128}$ or 97.9, whichever is smaller.		97.5
$10 \leq Y < 20$	74.0	$85.35X^{0.0144}Y^{0.0128}$ or 90.8, whichever is smaller.		90.8
$Y < 10$	74.0	74.0	74.0	74.0

E = The sulfur emission rate expressed as elemental sulfur, kilograms per hour (kg/hr) [pounds per hour (lb/hr)], rounded to one decimal place.
R = The sulfur emission reduction efficiency achieved in percent, carried to one decimal place.
S = The sulfur production rate, kilograms per hour (kg/hr) [pounds per hour (lb/hr)], rounded to one decimal place.

X = The sulfur feed rate from the sweetening unit (*i.e.,* the H_2S in the acid gas), expressed as sulfur, Mg/D(LT/D), rounded to one decimal place.

Y = The sulfur content of the acid gas from the sweetening unit, expressed as mole percent H_2S (dry basis) rounded to one decimal place.

Z = The minimum required sulfur dioxide (SO_2) emission reduction efficiency, expressed as percent carried to one decimal place. Z_i refers to the reduction efficiency required at the initial performance test. Z_c refers to the reduction efficiency required on a continuous basis after compliance with Z_i has been demonstrated.

As stated in § 60.5425, you must comply with the following applicable General Provisions:

TABLE 3 TO SUBPART OOOO OF PART 60—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART OOOO

General provisions citation	Subject of citation	Applies to subpart?	Explanation
§ 60.1	General applicability of the General Provisions	Yes.	
§ 60.2	Definitions	Yes	Additional terms defined in § 60.5430.
§ 60.3	Units and abbreviations	Yes.	
§ 60.4	Address	Yes.	
§ 60.5	Determination of construction or modification	Yes.	
§ 60.6	Review of plans	Yes.	
§ 60.7	Notification and record keeping	Yes	Except that § 60.7 only applies as specified in § 60.5420(a).
§ 60.8	Performance tests	Yes	Performance testing is required for control devices used on storage vessels and centrifugal compressors.
§ 60.9	Availability of information	Yes.	
§ 60.10	State authority	Yes.	
§ 60.11	Compliance with standards and maintenance requirements.	No	Requirements are specified in subpart OOOO.
§ 60.12	Circumvention	Yes.	
§ 60.13	Monitoring requirements	Yes	Continuous monitors are required for storage vessels.
§ 60.14	Modification	Yes.	
§ 60.15	Reconstruction	Yes.	
§ 60.16	Priority list	Yes.	
§ 60.17	Incorporations by reference	Yes.	
§ 60.18	General control device requirements	Yes	Except that § 60.18 does not apply to flares.
§ 60.19	General notification and reporting requirement	Yes.	

PART 63—NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS FOR SOURCE CATEGORIES

■ 8. The authority citation for part 63 continues to read as follows:

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

■ 9. Section 63.14 is amended by:

■ a. Revising paragraphs (b) introductory text, (b)(28), and (b)(64);

■ b. Adding paragraphs (b)(73), (74), and (75); and

■ c. Revising paragraphs (i) introductory text and (i)(1) to read as follows:

§ 63.14 Incorporations by reference.

* * * * *

(b) The following materials are available for purchase from at least one of the following addresses: American Society for Testing and Materials (ASTM), 100 Barr Harbor Drive, Post Office Box C700, West Conshohocken, PA 19428–2959, Telephone (610) 832–9585, and are also available at the following Web site: *http://www.astm.org*; or ProQuest, 789 East Eisenhower Parkway, Ann Arbor, MI 48106–1346, Telephone (734) 761–4700, and are also available at the following Web site: *http://www.proquest.com.*

* * * * *

(28) ASTM D6420–99 (Reapproved 2004), Standard Test Method for Determination of Gaseous Organic Compounds by Direct Interface Gas Chromatography-Mass Spectrometry (Approved October 1, 2004), IBR approved for §§ 60.485(g), 60.485a(g), 63.772(a), 63.772(e), 63.1282(a), 63.1282(d), 63.2351(b), 63.2354(b) and table 8 to subpart HHHHHHH of this part.

* * * * *

(64) ASTM D6522–00 (Reapproved 2005), Standard Test Method for Determination of Nitrogen Oxides, Carbon Monoxide, and Oxygen Concentrations in Emissions from Natural Gas Fired Reciprocating Engines, Combustion Turbines, Boilers, and Process Heaters Using Portable Analyzers, approved October 1, 2005, IBR approved for table 4 to subpart ZZZZ of this part, table 5 to subpart DDDDD of this part, table 4 to subpart JJJJJJ of this part and §§ 63.772(e), 63.772(h), 63.1282(d) and 63.1282(g).

* * * * *

(73) ASTM D1945–03 (Reapproved 2010) Standard Test Method for Analysis of Natural Gas by Gas Chromatography (Approved January 1, 2010), IBR approved for §§ 63.772(h) and 63.1282(g).

(74) ASTM D3588–98 (Reapproved 2003) Standard Practice for Calculating Heat Value, Compressibility Factor, and Relative Density of Gaseous Fuels (Approved May 10, 2003), IBR approved for §§ 63.772(h) and 63.1282(g).

(75) ASTM D4891–89 (Reapproved 2006) Standard Test Method for Heating Value of Gases in Natural Gas Range by Stoichiometric Combustion (Approved June 1, 2006), IBR approved for §§ 63.772(h) and 63.1282(g).

* * * * *

(i) The following material is available for purchase from at least one of the following addresses: American Society of Mechanical Engineers (ASME), Three Park Avenue, New York, NY 10016–

5990, Telephone (800) 843–2763, and are also available at the following Web site: *http://www.asme.org*; or HIS, Incorporated, 15 Inverness Way East, Englewood, CO 80112, Telephone (877) 413–5184, and are also available at the following Web site: *http://global.ihs.com*.

(1) ANSI/ASME PTC 19.10–1981, Flue and Exhaust Gas Analyses [Part 10, Instruments and Apparatus], issued August 31, 1981 IBR approved for §§ 63.309(k), 63.772(e), 63.772(h), 63.865(b), 63.1282(d), 63.1282(g), 63.3166(a), 63.3360(e), 63.3545(a), 63.3555(a), 63.4166(a), 63.4362(a), 63.4766(a), 63.4965(a), 63.5160(d), 63.9307(c), 63.9323(a), 63.11148(e), 63.11155(e), 63.11162(f), 63.11163(g), 63.11410(j), 63.11551(a) and 63.11646(a), 63.11945, table 5 to subpart DDDDD of this part, table 4 to subpart JJJJJ of this part, table 5 to subpart UUUUU of this part and table 1 to subpart ZZZZZ of this part.

* * * * *

Subpart HH—[Amended]

■ 10. Section 63.760 is amended by:
■ a. Revising paragraph (a)(1) introductory text;
■ b. Revising paragraph (a)(1)(i);
■ c. Revising paragraph (a)(1)(iii);
■ d. Revising paragraph (a)(2);
■ e. Revising paragraph (b)(1)(i);
■ f. Adding paragraph (c);
■ g. Revising paragraph (f) introductory text;
■ h. Revising paragraph (f)(1);
■ i. Revising paragraph (f)(2);
■ j. Adding paragraphs (f)(7), (f)(8), and (f)(9); and
■ k. Removing and reserving paragraph (g)(1).

The revisions and additions read as follows:

§ 63.760 Applicability and designation of affected source.

(a) * * *

(1) Facilities that are major or area sources of hazardous air pollutants (HAP) as defined in § 63.761. Emissions for major source determination purposes can be estimated using the maximum natural gas or hydrocarbon liquid throughput, as appropriate, calculated in paragraphs (a)(1)(i) through (iii) of this section. As an alternative to calculating the maximum natural gas or hydrocarbon liquid throughput, the owner or operator of a new or existing source may use the facility's design maximum natural gas or hydrocarbon liquid throughput to estimate the maximum potential emissions. Other means to determine the facility's major source status are allowed, provided the information is documented and recorded to the Administrator's satisfaction in accordance with § 63.10(b)(3). A facility that is determined to be an area source, but subsequently increases its emissions or its potential to emit above the major source levels, and becomes a major source, must comply thereafter with all provisions of this subpart applicable to a major source starting on the applicable compliance date specified in paragraph (f) of this section. Nothing in this paragraph is intended to preclude a source from limiting its potential to emit through other appropriate mechanisms that may be available through the permitting authority.

(i) If the owner or operator documents, to the Administrator's satisfaction, a decline in annual natural gas or hydrocarbon liquid throughput, as appropriate, each year for the 5 years prior to October 15, 2012, the owner or operator shall calculate the maximum natural gas or hydrocarbon liquid throughput used to determine maximum potential emissions according to the requirements specified in paragraph (a)(1)(i)(A) of this section. In all other circumstances, the owner or operator shall calculate the maximum throughput used to determine whether a facility is a major source in accordance with the requirements specified in paragraph (a)(1)(i)(B) of this section.

(A) The maximum natural gas or hydrocarbon liquid throughput is the average of the annual natural gas or hydrocarbon liquid throughput for the 3 years prior to October 15, 2012, multiplied by a factor of 1.2.

(B) The maximum natural gas or hydrocarbon liquid throughput is the highest annual natural gas or hydrocarbon liquid throughput over the 5 years prior to October 15, 2012, multiplied by a factor of 1.2.

* * * * *

(iii) The owner or operator shall determine the maximum values for other parameters used to calculate emissions as the maximum for the period over which the maximum natural gas or hydrocarbon liquid throughput is determined in accordance with paragraph (a)(1)(i)(A) or (B) of this section. Parameters, other than glycol circulation rate, shall be based on either highest measured values or annual average. For estimating maximum potential emissions from glycol dehydration units, the glycol circulation rate used in the calculation shall be the unit's maximum rate under its physical and operational design consistent with the definition of potential to emit in § 63.2.

(2) Facilities that process, upgrade, or store hydrocarbon liquids.

* * * * *

(b) * * *

(1) * * *

(i) Each glycol dehydration unit as specified in paragraphs (b)(1)(i)(A) through (C) of this section.

(A) Each large glycol dehydration unit;

(B) Each small glycol dehydration unit for which construction commenced on or before August 23, 2011, is an existing small glycol dehydration unit; and

(C) Each small glycol dehydration unit for which construction commenced after August 23, 2011, is a new small glycol dehydration unit.

* * * * *

(c) Any source that determines it is not a major source but has actual emissions of 5 tons per year or more of a single HAP, or 12.5 tons per year or more of a combination of HAP (*i.e.,* 50 percent of the major source thresholds), shall update its major source determination within 1 year of the prior determination or October 15, 2012, whichever is later, and each year thereafter, using gas composition data measured during the preceding 12 months.

* * * * *

(f) The owner or operator of an affected major source shall achieve compliance with the provisions of this subpart by the dates specified in paragraphs (f)(1), (2), and (f)(7) through (9) of this section. The owner or operator of an affected area source shall achieve compliance with the provisions of this subpart by the dates specified in paragraphs (f)(3) through (6) of this section.

(1) Except as specified in paragraphs (f)(7) through (9) of this section, the owner or operator of an affected major source, the construction or reconstruction of which commenced before February 6, 1998, shall achieve compliance with the applicable provisions of this subpart no later than June 17, 2002, except as provided for in § 63.6(i). The owner or operator of an area source, the construction or reconstruction of which commenced before February 6, 1998, that increases its emissions of (or its potential to emit) HAP such that the source becomes a major source that is subject to this subpart shall comply with this subpart 3 years after becoming a major source.

(2) Except as specified in paragraphs (f)(7) through (9) of this section, the owner or operator of an affected major source, the construction or reconstruction of which commences on

or after February 6, 1998, shall achieve compliance with the applicable provisions of this subpart immediately upon initial startup or June 17, 1999, whichever date is later. Area sources, other than production field facilities identified in (f)(9) of this section, the construction or reconstruction of which commences on or after February 6, 1998, that become major sources shall comply with the provisions of this standard immediately upon becoming a major source.

* * * * *

(7) Each affected existing small glycol dehydration unit, as defined in § 63.761, located at a major source, that commenced construction before August 23, 2011, must achieve compliance no later than October 15, 2015, except as provided in § 63.6(i).

(8) Each affected new small glycol dehydration unit, as defined in § 63.761, located at a major source, that commenced construction on or after August 23, 2011, must achieve compliance immediately upon initial startup or October 15, 2012, whichever is later.

(9) A production field facility, as defined in § 63.761, constructed on or before August 23, 2011, that was previously determined to be an area source but becomes a major source (as defined in paragraph 3 of the major source definition in § 63.761) on the October 15, 2012 must achieve compliance no later than October 15, 2015, except as provided in § 63.6(i).

* * * * *

■ 11. Section 63.761 is amended by:

■ a. Adding, in alphabetical order, definitions for the terms ''affirmative defense,'' ''BTEX,'' ''flare,'' ''large glycol dehydration unit,'' ''responsible official'' and ''small glycol dehydration unit'';

■ b. Revising the definitions for ''associated equipment,'' ''glycol dehydration unit baseline operations,'' and ''storage vessel''; and

■ c. Revising paragraph (3) of the definition for ''major source'' to read as follows:

§ 63.761 Definitions.

* * * * *

Affirmative defense means, in the context of an enforcement proceeding, a response or defense put forward by a defendant, regarding which the defendant has the burden of proof, and the merits of which are independently and objectively evaluated in a judicial or administrative proceeding.

* * * * *

Associated equipment, as used in this subpart and as referred to in section 112(n)(4) of the Act, means equipment associated with an oil or natural gas exploration or production well, and includes all equipment from the wellbore to the point of custody transfer, except glycol dehydration units and storage vessels.

* * * * *

BTEX means benzene, toluene, ethyl benzene and xylene.

* * * * *

Flare means a thermal oxidation system using an open flame (*i.e.,* without enclosure).

* * * * *

Glycol dehydration unit baseline operations means operations representative of the large glycol dehydration unit operations as of June 17, 1999 and the small glycol dehydrator unit operations as of August 23, 2011. For the purposes of this subpart, for determining the percentage of overall HAP emission reduction attributable to process modifications, baseline operations shall be parameter values (including, but not limited to, glycol circulation rate or glycol-HAP absorbency) that represent actual long-term conditions (*i.e.,* at least 1 year). Glycol dehydration units in operation for less than 1 year shall document that the parameter values represent expected long-term operating conditions had process modifications not been made.

* * * * *

Large glycol dehydration unit means a glycol dehydration unit with an actual annual average natural gas flowrate equal to or greater than 85 thousand standard cubic meters per day and actual annual average benzene emissions equal to or greater than 0.90 Mg/yr, determined according to § 63.772(b). A glycol dehydration unit complying with the 0.9 Mg/yr control option under § 63.765(b)(1)(ii) is considered to be a large dehydrator.

Major source * * *

(3) For facilities that are production field facilities, only HAP emissions from glycol dehydration units and storage vessels shall be aggregated for a major source determination. For facilities that are not production field facilities, HAP emissions from all HAP emission units shall be aggregated for a major source determination.

* * * * *

Responsible official means one of the following:

(1) For a corporation: A president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit and either:

(i) The facilities employ more than 250 persons or have gross annual sales or expenditures exceeding $25 million (in second quarter 1980 dollars); or

(ii) The delegation of authority to such representatives is approved in advance by the permitting authority;

(2) For a partnership or sole proprietorship: a general partner or the proprietor, respectively;

(3) For a municipality, State, Federal, or other public agency: Either a principal executive officer or ranking elected official. For the purposes of this part, a principal executive officer of a Federal agency includes the chief executive officer having responsibility for the overall operations of a principal geographic unit of the agency (*e.g.,* a Regional Administrator of EPA); or

(4) For affected sources:

(i) The designated representative in so far as actions, standards, requirements, or prohibitions under title IV of the Act or the regulations promulgated thereunder are concerned; and

(ii) The designated representative for any other purposes under part 70.

* * * * *

Small glycol dehydration unit means a glycol dehydration unit, located at a major source, with an actual annual average natural gas flowrate less than 85 thousand standard cubic meters per day or actual annual average benzene emissions less than 0.90 Mg/yr, determined according to § 63.772(b).

* * * * *

Storage vessel means a tank or other vessel that is designed to contain an accumulation of crude oil, condensate, intermediate hydrocarbon liquids, or produced water and that is constructed primarily of non-earthen materials (*e.g.,* wood, concrete, steel, plastic) that provide structural support. The following process units are not considered storage vessels: Surge control vessels and knockout vessels.

* * * * *

■ 12. Section 63.762 is revised to read as follows:

§ 63.762 Affirmative defense for violations of emission standards during malfunction.

(a) The provisions set forth in this subpart shall apply at all times.

(b) [Reserved]

(c) [Reserved]

(d) In response to an action to enforce the standards set forth in this subpart, you may assert an affirmative defense to

a claim for civil penalties for violations of such standards that are caused by malfunction, as defined in 40 CFR 63.2. Appropriate penalties may be assessed; however, if you fail to meet your burden of proving all of the requirements in the affirmative defense, the affirmative defense shall not be available for claims for injunctive relief.

(1) To establish the affirmative defense in any action to enforce such a standard, you must timely meet the reporting requirements in paragraph (d)(2) of this section, and must prove by a preponderance of evidence that:

(i) The violation:

(A) Was caused by a sudden, infrequent, and unavoidable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner; and

(B) Could not have been prevented through careful planning, proper design or better operation and maintenance practices; and

(C) Did not stem from any activity or event that could have been foreseen and avoided, or planned for; and

(D) Was not part of a recurring pattern indicative of inadequate design, operation, or maintenance; and

(ii) Repairs were made as expeditiously as possible when a violation occurred. Off-shift and overtime labor were used, to the extent practicable to make these repairs; and

(iii) The frequency, amount and duration of the violation (including any bypass) were minimized to the maximum extent practicable; and

(iv) If the violation resulted from a bypass of control equipment or a process, then the bypass was unavoidable to prevent loss of life, personal injury, or severe property damage; and

(v) All possible steps were taken to minimize the impact of the violation on ambient air quality, the environment, and human health; and

(vi) All emissions monitoring and control systems were kept in operation if at all possible, consistent with safety and good air pollution control practices; and

(vii) All of the actions in response to the violation were documented by properly signed, contemporaneous operating logs; and

(viii) At all times, the affected source was operated in a manner consistent with good practices for minimizing emissions; and

(ix) A written root cause analysis has been prepared, the purpose of which is to determine, correct, and eliminate the primary causes of the malfunction and the violation resulting from the malfunction event at issue. The analysis shall also specify, using best monitoring methods and engineering judgment, the amount of any emissions that were the result of the malfunction.

(2) *Report.* The owner or operator seeking to assert an affirmative defense shall submit a written report to the Administrator with all necessary supporting documentation, that it has met the requirements set forth in paragraph (d)(1) of this section. This affirmative defense report shall be included in the first periodic compliance, deviation report or excess emission report otherwise required after the initial occurrence of the violation of the relevant standard (which may be the end of any applicable averaging period). If such compliance, deviation report or excess emission report is due less than 45 days after the initial occurrence of the violation, the affirmative defense report may be included in the second compliance, deviation report or excess emission report due after the initial occurrence of the violation of the relevant standard.

■ 13. Section 63.764 is amended by:
■ a. Revising paragraph (e)(1) introductory text;
■ b. Revising paragraph (i); and
■ c. Adding paragraph (j).

The revisions and addition read as follows:

§ 63.764 General standards.

* * * * *

(e) *Exemptions.* (1) The owner or operator of an area source is exempt from the requirements of paragraph (d) of this section if the criteria listed in paragraph (e)(1)(i) or (ii) of this section are met, except that the records of the determination of these criteria must be maintained as required in § 63.774(d)(1).

* * * * *

(i) In all cases where the provisions of this subpart require an owner or operator to repair leaks by a specified time after the leak is detected, it is a violation of this standard to fail to take action to repair the leak(s) within the specified time. If action is taken to repair the leak(s) within the specified time, failure of that action to successfully repair the leak(s) is not a violation of this standard. However, if the repairs are unsuccessful, and a leak is detected, the owner or operator shall take further action as required by the applicable provisions of this subpart.

(j) At all times the owner or operator must operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.

■ 14. Section 63.765 is amended by:
■ a. Revising paragraph (a);
■ b. Revising paragraph (b)(1);
■ c. Revising paragraph (c)(2); and
■ d. Revising paragraph (c)(3).

The revisions read as follows:

§ 63.765 Glycol dehydration unit process vent standards.

(a) This section applies to each glycol dehydration unit subject to this subpart that must be controlled for air emissions as specified in either paragraph (c)(1)(i) or paragraph (d)(1)(i) of § 63.764.

(b) * * *

(1) For each glycol dehydration unit process vent, the owner or operator shall control air emissions by either paragraph (b)(1)(i), (ii), or (iii) of this section.

(i) The owner or operator of a large glycol dehydration unit, as defined in § 63.761, shall connect the process vent to a control device or a combination of control devices through a closed-vent system. The closed-vent system shall be designed and operated in accordance with the requirements of § 63.771(c). The control device(s) shall be designed and operated in accordance with the requirements of § 63.771(d).

(ii) The owner or operator of a large glycol dehydration unit shall connect the process vent to a control device or combination of control devices through a closed-vent system and the outlet benzene emissions from the control device(s) shall be reduced to a level less than 0.90 megagrams per year. The closed-vent system shall be designed and operated in accordance with the requirements of § 63.771(c). The control device(s) shall be designed and operated in accordance with the requirements of § 63.771(d), except that the performance levels specified in § 63.771(d)(1)(i) and (ii) do not apply.

(iii) You must limit BTEX emissions from each existing small glycol dehydration unit process vent, as defined in § 63.761, to the limit determined in Equation 1 of this section. You must limit BTEX emissions from each new small glycol dehydration unit process vent, as defined in § 63.761, to the limit determined in Equation 2 of this section. The limits determined using Equation 1 or Equation 2 must be met in accordance

with one of the alternatives specified in paragraphs (b)(1)(iii)(A) through (D) of this section.

$$EL_{BTEX} = 3.28x10^{-4} * Throughput * C_{i,BTEX} * 365 \frac{days}{yr} * \frac{1\ Mg}{1x10^{6}\ grams}$$

Equation 1

Where:

EL_{BTEX} = Unit-specific BTEX emission limit, megagrams per year;

3.28×10^{-4} = BTEX emission limit, grams BTEX/standard cubic meter-ppmv;

Throughput = Annual average daily natural gas throughput, standard cubic meters per day.

$C_{i,BTEX}$ = average annual BTEX concentration of the natural gas at the inlet to the glycol dehydration unit, ppmv.

$$EL_{BTEX} = 4.66x10^{-6} * Throughput * C_{i,BTEX} * 365 \frac{days}{yr} * \frac{1\ Mg}{1x10^{6}\ grams}$$

Where:

EL_{BTEX} = Unit-specific BTEX emission limit, megagrams per year;

4.66×10^{-6} = BTEX emission limit, grams BTEX/standard cubic meter-ppmv;

Throughput = Annual average daily natural gas throughput, standard cubic meters per day.

$C_{i,BTEX}$ = average annual BTEX concentration of the natural gas at the inlet to the glycol dehydration unit, ppmv.

(A) Connect the process vent to a control device or combination of control devices through a closed-vent system. The closed vent system shall be designed and operated in accordance with the requirements of § 63.771(c). The control device(s) shall be designed and operated in accordance with the requirements of § 63.771(f).

(B) Meet the emissions limit through process modifications in accordance with the requirements specified in § 63.771(e).

(C) Meet the emissions limit for each small glycol dehydration unit using a combination of process modifications and one or more control devices through the requirements specified in paragraphs (b)(1)(iii)(A) and (B) of this section.

(D) Demonstrate that the emissions limit is met through actual uncontrolled operation of the small glycol dehydration unit. Document operational parameters in accordance with the requirements specified in § 63.771(e) and emissions in accordance with the requirements specified in § 63.772(b)(2).

* * * * *

(c) * * *

(2) The owner or operator shall demonstrate, to the Administrator's satisfaction, that the total HAP emissions to the atmosphere from the large glycol dehydration unit process vent are reduced by 95.0 percent through process modifications, or a combination of process modifications and one or more control devices, in accordance with the requirements specified in § 63.771(e).

(3) Control of HAP emissions from a GCG separator (flash tank) vent is not required if the owner or operator demonstrates, to the Administrator's satisfaction, that total emissions to the atmosphere from the glycol dehydration unit process vent are reduced by one of the levels specified in paragraph (c)(3)(i) through (iv) of this section, through the installation and operation of controls as specified in paragraph (b)(1) of this section.

(i) For any large glycol dehydration unit, HAP emissions are reduced by 95.0 percent or more.

(ii) For any large glycol dehydration unit, benzene emissions are reduced to a level less than 0.90 megagrams per year.

(iii) For each existing small glycol dehydration unit, BTEX emissions are reduced to a level less than the limit calculated by Equation 1 of paragraph (b)(1)(iii) of this section.

(iv) For each new small glycol dehydration unit, BTEX emissions are reduced to a level less than the limit calculated by Equation 2 of paragraph (b)(1)(iii) of this section.

■ 15. Section 63.766 is amended by:

■ a. Adding paragraph (b)(3); and

■ b. Revising paragraph (d) to read as follows:

§ 63.766 Storage vessel standards.

* * * * *

(b) * * *

(3) The owner or operator shall control air emissions by connecting the cover, through a closed-vent system that meets the conditions specified in § 63.771(c), to a process natural gas line.

* * * * *

(d) This section does not apply to storage vessels for which the owner or operator is subject to and controlled under the requirements specified in 40 CFR part 60, subparts Kb or OOOO; or is subject to and controlled under 40 CFR part 63 subparts G or CC. Storage vessels subject to and controlled under 40 CFR part 60, subpart OOOO shall submit the periodic reports specified in § 63.775(e).

■ 16. Section 63.769 is amended by:

■ a. Revising paragraph (b);

■ b. Revising paragraph (c) introductory text; and

■ c. Revising paragraph (c)(8).

The revisions read as follows:

§ 63.769 Equipment leak standards.

* * * * *

(b) This section does not apply to ancillary equipment and compressors for which the owner or operator is subject to and controlled under the requirements specified in subpart H of this part; or is subject to and controlled under the requirements specified in 40 CFR part 60, subpart OOOO. Ancillary equipment and compressors subject to and controlled under 40 CFR part 60, subpart OOOO shall submit the periodic reports specified in § 63.775(e).

(c) For each piece of ancillary equipment and each compressor subject to this section located at an existing or new source, the owner or operator shall meet the requirements specified in 40 CFR part 61, subpart V, §§ 61.241 through 61.247, except as specified in paragraphs (c)(1) through (8) of this section, except that for valves subject to § 61.242–7(b) or § 61.243–1, a leak is detected if an instrument reading of 500 ppm or greater is measured. A leak detected from a valve at a source constructed on or before August 23, 2011 shall be repaired in accordance with the schedule in § 61.242–7(d), or by October 15, 2013, whichever is later. A leak detected from a valve at a source constructed after August 23, 2011 shall be repaired in accordance with the schedule in § 61.242–7(d), or by October 15, 2012, whichever is later.

* * * * *

(8) Flares, as defined in § 63.761, used to comply with this subpart shall comply with the requirements of § 63.11(b).

■ 17. Section 63.771 is amended by:
■ a. Revising paragraph (c)(1);
■ b. Revising the heading of paragraph (d);
■ c. Adding paragraph (d) introductory text;
■ d. Revising paragraph (d)(1)(i)(C);
■ e. Revising paragraph (d)(1)(ii);
■ f. Revising paragraph (d)(1)(iii);
■ g. Revising paragraph (d)(4)(i);
■ h. Revising paragraph (d)(5)(i);
■ i. Revising paragraph (e)(2);
■ j. Revising paragraph (e)(3) introductory text;
■ k. Revising paragraph (e)(3)(ii); and
■ l. Adding paragraph (f).

The revisions and additions read as follows:

§ 63.771 Control equipment requirements.

* * * * *

(c) *Closed-vent system requirements.* (1) The closed-vent system shall route all gases, vapors, and fumes emitted from the material in an emissions unit to a control device that meets the requirements specified in paragraph (d) of this section.

* * * * *

(d) *Control device requirements for sources except small glycol dehydration units.* Owners and operators of small glycol dehydration units, shall comply with the control device requirements in paragraph (f) of this section.

(1) * * *

(i) * * *

(C) Operates at a minimum temperature of 760 degrees C, provided the control device has demonstrated, under § 63.772(e), that combustion zone temperature is an indicator of destruction efficiency.

* * * * *

(ii) A vapor recovery device (*e.g.,* carbon adsorption system or condenser) or other non-destructive control device that is designed and operated to reduce the mass content of either TOC or total HAP in the gases vented to the device by 95.0 percent by weight or greater as determined in accordance with the requirements of § 63.772(e).

(iii) A flare, as defined in § 63.761, that is designed and operated in accordance with the requirements of § 63.11(b).

* * * * *

(4) * * *

(i) Each control device used to comply with this subpart shall be operating at all times when gases, vapors, and fumes are vented from the HAP emissions unit or units through the closed-vent system to the control device, as required under § 63.765, § 63.766, and § 63.769. An owner or operator may vent more than one unit to a control device used to comply with this subpart.

* * * * *

(5) * * *

(i) Following the initial startup of the control device, all carbon in the control device shall be replaced with fresh carbon on a regular, predetermined time interval that is no longer than the carbon service life established for the carbon adsorption system. Records identifying the schedule for replacement and records of each carbon replacement shall be maintained as required in § 63.774(b)(7)(ix). The schedule for replacement shall be submitted with the Notification of Compliance Status Report as specified in § 63.775(d)(5)(iv). Each carbon replacement must be reported in the Periodic Reports as specified in § 63.772(e)(2)(xii).

* * * * *

(e) * * *

(2) The owner or operator shall document, to the Administrator's satisfaction, the conditions for which glycol dehydration unit baseline operations shall be modified to achieve the 95.0 percent overall HAP emission reduction, or BTEX limit determined in § 63.765(b)(1)(iii), as applicable, either through process modifications or through a combination of process modifications and one or more control devices. If a combination of process modifications and one or more control devices are used, the owner or operator shall also establish the emission reduction to be achieved by the control device to achieve an overall HAP emission reduction of 95.0 percent for the glycol dehydration unit process vent or, if applicable, the BTEX limit determined in § 63.765(b)(1)(iii) for the small glycol dehydration unit process vent. Only modifications in glycol dehydration unit operations directly related to process changes, including but not limited to changes in glycol circulation rate or glycol-HAP absorbency, shall be allowed. Changes in the inlet gas characteristics or natural gas throughput rate shall not be considered in determining the overall emission reduction due to process modifications.

(3) The owner or operator that achieves a 95.0 percent HAP emission reduction or meets the BTEX limit determined in § 63.765(b)(1)(iii), as applicable, using process modifications alone shall comply with paragraph (e)(3)(i) of this section. The owner or operator that achieves a 95.0 percent HAP emission reduction or meets the BTEX limit determined in § 63.765(b)(1)(iii), as applicable, using a combination of process modifications and one or more control devices shall comply with paragraphs (e)(3)(i) and (ii) of this section.

* * * * *

(ii) The owner or operator shall comply with the control device requirements specified in paragraph (d) or (f) of this section, as applicable, except that the emission reduction or limit achieved shall be the emission reduction or limit specified for the control device(s) in paragraph (e)(2) of this section.

(f) *Control device requirements for small glycol dehydration units.* (1) The control device used to meet BTEX the emission limit calculated in § 63.765(b)(1)(iii) shall be one of the control devices specified in paragraphs (f)(1)(i) through (iii) of this section.

(i) An enclosed combustion device (*e.g.,* thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater) that is designed and operated to meet the levels specified in paragraphs (f)(1)(i)(A) or (B) of this section. If a boiler or process heater is used as the control device, then the vent stream shall be introduced into the flame zone of the boiler or process heater.

(A) The mass content of BTEX in the gases vented to the device is reduced as determined in accordance with the requirements of § 63.772(e).

(B) The concentration of either TOC or total HAP in the exhaust gases at the outlet of the device is reduced to a level equal to or less than 20 parts per million by volume on a dry basis corrected to 3 percent oxygen as determined in accordance with the requirements of § 63.772(e).

(ii) A vapor recovery device (*e.g.,* carbon adsorption system or condenser) or other non-destructive control device that is designed and operated to reduce the mass content of BTEX in the gases vented to the device as determined in accordance with the requirements of § 63.772(e).

(iii) A flare, as defined in § 63.761, that is designed and operated in accordance with the requirements of § 63.11(b).

(2) The owner or operator shall operate each control device in accordance with the requirements specified in paragraphs (f)(2)(i) and (ii) of this section.

(i) Each control device used to comply with this subpart shall be operating at all times. An owner or operator may vent more than one unit to a control device used to comply with this subpart.

(ii) For each control device monitored in accordance with the requirements of § 63.773(d), the owner or operator shall demonstrate compliance according to the requirements of either § 63.772(f) or (h).

(3) For each carbon adsorption system used as a control device to meet the requirements of paragraph (f)(1)(ii) of this section, the owner or operator shall manage the carbon as required under (d)(5)(i) and (ii) of this section.

■ 18. Section 63.772 is amended by:
■ a. Revising paragraph (b) introductory text;
■ b. Revising paragraph (b)(1)(ii);
■ c. Revising paragraph (b)(2);
■ d. Revising paragraph (c)(6)(i);
■ e. Adding paragraph (d);
■ f. Revising paragraph (e) introductory text;
■ g. Revising paragraphs (e)(1)(i) through (v);
■ h. Revising paragraph (e)(2);
■ i. Revising paragraph (e)(3) introductory text;
■ j. Revising paragraph (e)(3)(i)(B);
■ k. Revising paragraph (e)(3)(iv)(C)(*1*);
■ l. Adding paragraphs (e)(3)(v) and (vi);
■ m. Revising paragraph (e)(4) introductory text;
■ n. Revising paragraph (e)(4)(i);
■ o. Revising paragraph (e)(5);
■ p. Revising paragraph (f) introductory text;
■ q. Revising paragraphs (f)(2) and (3);
■ r. Adding paragraphs (f)(4) through (6);
■ s. Revising paragraph (g) introductory text;
■ t. Revising paragraph (g)(1) and paragraph (g)(2) introductory text;
■ u. Revising paragraph (g)(2)(iii);
■ v. Revising paragraph (g)(3);
■ w. Adding paragraph (h); and
■ x. Adding paragraph (i).

The revisions and additions read as follows:

§ 63.772 Test methods, compliance procedures, and compliance demonstrations.

* * * * *

(b) *Determination of glycol dehydration unit flowrate, benzene emissions, or BTEX emissions.* The procedures of this paragraph shall be used by an owner or operator to determine glycol dehydration unit natural gas flowrate, benzene emissions, or BTEX emissions.

(1) * * *

(ii) The owner or operator shall document, to the Administrator's satisfaction, the actual annual average natural gas flowrate to the glycol dehydration unit.

(2) The determination of actual average benzene or BTEX emissions from a glycol dehydration unit shall be made using the procedures of either paragraph (b)(2)(i) or (ii) of this section. Emissions shall be determined either uncontrolled, or with federally enforceable controls in place.

(i) The owner or operator shall determine actual average benzene or BTEX emissions using the model GRI–GLYCalc™, Version 3.0 or higher, and the procedures presented in the associated GRI–GLYCalc™ Technical Reference Manual. Inputs to the model shall be representative of actual operating conditions of the glycol dehydration unit and may be determined using the procedures documented in the Gas Research Institute (GRI) report entitled ''Atmospheric Rich/Lean Method for Determining Glycol Dehydrator Emissions'' (GRI–95/0368.1); or

(ii) The owner or operator shall determine an average mass rate of benzene or BTEX emissions in kilograms per hour through direct measurement using the methods in § 63.772(a)(1)(i) or (ii), or an alternative method according to § 63.7(f). Annual emissions in kilograms per year shall be determined by multiplying the mass rate by the number of hours the unit is operated per year. This result shall be converted to megagrams per year.

(c) * * *

(6) * * *

(i) Except as provided in paragraph (c)(6)(ii) of this section, the detection instrument shall meet the performance criteria of Method 21 of 40 CFR part 60, appendix A, except the instrument response factor criteria in section 3.1.2(a) of Method 21 shall be for the average composition of the process fluid, not each individual volatile organic compound in the stream. For process streams that contain nitrogen, air, or other inert gases that are not organic hazardous air pollutants or volatile organic compounds, the average stream response factor shall be calculated on an inert-free basis.

* * * * *

(d) *Test procedures and compliance demonstrations for small glycol dehydration units.* This paragraph applies to the test procedures for small dehydration units.

(1) If the owner or operator is using a control device to comply with the emission limit in § 63.765(b)(1)(iii), the requirements of paragraph (e) of this section apply. Compliance is demonstrated using the methods specified in paragraph (f) of this section.

(2) If no control device is used to comply with the emission limit in § 63.765(b)(1)(iii), the owner or operator must determine the glycol dehydration unit BTEX emissions as specified in paragraphs (d)(2)(i) through (iii) of this section. Compliance is demonstrated if the BTEX emissions determined as specified in paragraphs (d)(2)(i) through (iii) are less than the emission limit calculated using the equation in § 63.765(b)(1)(iii).

(i) Method 1 or 1A, 40 CFR part 60, appendix A, as appropriate, shall be used for selection of the sampling sites at the outlet of the glycol dehydration unit process vent. Any references to particulate mentioned in Methods 1 and 1A do not apply to this section.

(ii) The gas volumetric flowrate shall be determined using Method 2, 2A, 2C, or 2D, 40 CFR part 60, appendix A, as appropriate.

(iii) The BTEX emissions from the outlet of the glycol dehydration unit process vent shall be determined using the procedures specified in paragraph (e)(3)(v) of this section. As an alternative, the mass rate of BTEX at the outlet of the glycol dehydration unit process vent may be calculated using the model GRI–GLYCalc™, Version 3.0 or higher, and the procedures presented in the associated GRI–GLYCalc™ Technical Reference Manual. Inputs to the model shall be representative of actual operating conditions of the glycol dehydration unit and shall be determined using the procedures documented in the Gas Research Institute (GRI) report entitled ''Atmospheric Rich/Lean Method for Determining Glycol Dehydrator Emissions'' (GRI–95/0368.1). When the BTEX mass rate is calculated for glycol dehydration units using the model GRI–GLYCalc™, all BTEX measured by Method 18, 40 CFR part 60, appendix A, shall be summed.

(e) *Control device performance test procedures.* This paragraph applies to the performance testing of control devices. The owners or operators shall demonstrate that a control device achieves the performance requirements of § 63.771(d)(1), (e)(3)(ii) or (f)(1) using a performance test as specified in paragraph (e)(3) of this section. Owners or operators using a condenser have the option to use a design analysis as specified in paragraph (e)(4) of this section. The owner or operator may elect to use the alternative procedures in paragraph (e)(5) of this section for performance testing of a condenser used to control emissions from a glycol dehydration unit process vent. Flares shall meet the provisions in paragraph (e)(2) of this section. As an alternative to conducting a performance test under this section for combustion control devices, a control device that can be

demonstrated to meet the performance requirements of § 63.771(d)(1), (e)(3)(ii) or (f)(1) through a performance test conducted by the manufacturer, as specified in paragraph (h) of this section, can be used.

(1) * * *

(i) Except as specified in paragraph (e)(2) of this section, a flare, as defined in § 63.761, that is designed and operated in accordance with § 63.11(b);

(ii) Except for control devices used for small glycol dehydration units, a boiler or process heater with a design heat input capacity of 44 megawatts or greater;

(iii) Except for control devices used for small glycol dehydration units, a boiler or process heater into which the vent stream is introduced with the primary fuel or is used as the primary fuel;

(iv) Except for control devices used for small glycol dehydration units, a boiler or process heater burning hazardous waste for which the owner or operator has either been issued a final permit under 40 CFR part 270 and complies with the requirements of 40 CFR part 266, subpart H; or has certified compliance with the interim status requirements of 40 CFR part 266, subpart H;

(v) Except for control devices used for small glycol dehydration units, a hazardous waste incinerator for which the owner or operator has been issued a final permit under 40 CFR part 270 and complies with the requirements of 40 CFR part 264, subpart O; or has certified compliance with the interim status requirements of 40 CFR part 265, subpart O.

* * * * *

(2) An owner or operator shall design and operate each flare, as defined in § 63.761, in accordance with the requirements specified in § 63.11(b) and the compliance determination shall be conducted using Method 22 of 40 CFR part 60, appendix A, to determine visible emissions.

(3) For a performance test conducted to demonstrate that a control device meets the requirements of § 63.771(d)(1), (e)(3)(ii) or (f)(1), the owner or operator shall use the test methods and procedures specified in paragraphs (e)(3)(i) through (v) of this section. The initial and periodic performance tests shall be conducted according to the schedule specified in paragraph (e)(3)(vi) of this section.

(i) * * *

(B) To determine compliance with the enclosed combustion device total HAP concentration limit specified in § 63.771(d)(1)(i)(B), or the BTEX emission limit specified in § 63.765(b)(1)(iii) the sampling site shall be located at the outlet of the combustion device.

* * * * *

(iv) * * *

(C) * * *

(*1*) The emission rate correction factor for excess air, integrated sampling and analysis procedures of Method 3A or 3B, 40 CFR part 60, appendix A, ASTM D6522–00 (Reapproved 2005), or ANSI/ASME PTC 19.10–1981, Part 10 (manual portion only) (incorporated by reference as specified in § 63.14) shall be used to determine the oxygen concentration. The samples shall be taken during the same time that the samples are taken for determining TOC concentration or total HAP concentration.

* * * * *

(v) To determine compliance with the BTEX emission limit specified in § 63.765(b)(1)(iii) the owner or operator shall use one of the following methods: Method 18, 40 CFR part 60, appendix A; ASTM D6420–99 (Reapproved 2004), as specified in § 63.772(a)(1)(ii) (incorporated by reference as specified in § 63.14); or any other method or data that have been validated according to the applicable procedures in Method 301, 40 CFR part 63, appendix A. The following procedures shall be used to calculate BTEX emissions:

(A) The minimum sampling time for each run shall be 1 hour in which either an integrated sample or a minimum of four grab samples shall be taken. If grab sampling is used, then the samples shall be taken at approximately equal intervals in time, such as 15-minute intervals during the run.

(B) The mass rate of BTEX (E_o) shall be computed using the equations and procedures specified in paragraphs (e)(3)(v)(B)(*1*) and (*2*) of this section.

(*1*) The following equation shall be used:

$$E_o = K_2\left(\sum_{j=1}^{n} C_{oj}M_{oj}\right)Q_o$$

Where:

E_o = Mass rate of BTEX at the outlet of the control device, dry basis, kilogram per hour.

C_{oj} = Concentration of sample component j of the gas stream at the outlet of the control device, dry basis, parts per million by volume.

M_{oj} = Molecular weight of sample component j of the gas stream at the outlet of the control device, gram/gram-mole.

Q_o = Flowrate of gas stream at the outlet of the control device, dry standard cubic meter per minute.

K_2 = Constant, 2.494×10^{-6} (parts per million) (gram-mole per standard cubic meter) (kilogram/gram) (minute/hour), where standard temperature (gram-mole per standard cubic meter) is 20 degrees C.

n = Number of components in sample.

(*2*) When the BTEX mass rate is calculated, only BTEX compounds measured by Method 18, 40 CFR part 60, appendix A, or ASTM D6420–99 (Reapproved 2004) (incorporated by reference as specified in § 63.14) as specified in § 63.772(a)(1)(ii), shall be summed using the equations in paragraph (e)(3)(v)(B)(*1*) of this section.

(vi) The owner or operator shall conduct performance tests according to the schedule specified in paragraphs (e)(3)(vi)(A) and (B) of this section.

(A) An initial performance test shall be conducted within 180 days after the compliance date that is specified for each affected source in § 63.760(f)(7) through (8), except that the initial performance test for existing combustion control devices (*i.e.,* control devices installed on or before August 23, 2011) at major sources shall be conducted no later than October 15, 2015. If the owner or operator of an existing combustion control device at a major source chooses to replace such device with a control device whose model is tested under § 63.772(h), then the newly installed device shall comply with all provisions of this subpart no later than October 15, 2015. The performance test results shall be submitted in the Notification of Compliance Status Report as required in § 63.775(d)(1)(ii).

(B) Periodic performance tests shall be conducted for all control devices required to conduct initial performance tests except as specified in paragraphs (e)(3)(vi)(B)(*1*) and (*2*) of this section. The first periodic performance test shall be conducted no later than 60 months after the initial performance test required in paragraph (e)(3)(vi)(A) of this section. Subsequent periodic performance tests shall be conducted at intervals no longer than 60 months following the previous periodic performance test or whenever a source desires to establish a new operating limit. The periodic performance test results must be submitted in the next Periodic Report as specified in § 63.775(e)(2)(xi). Combustion control devices meeting the criteria in either paragraph (e)(3)(vi)(B)(*1*) or (*2*) of this section are not required to conduct periodic performance tests.

(*1*) A control device whose model is tested under, and meets the criteria of, § 63.772(h), or

(*2*) A combustion control device demonstrating during the performance test under § 63.772(e) that combustion

zone temperature is an indicator of destruction efficiency and operates at a minimum temperature of 760 degrees C.

(4) For a condenser design analysis conducted to meet the requirements of § 63.771(d)(1), (e)(3)(ii), or (f)(1), the owner or operator shall meet the requirements specified in paragraphs (e)(4)(i) and (ii) of this section. Documentation of the design analysis shall be submitted as a part of the Notification of Compliance Status Report as required in § 63.775(d)(1)(i).

(i) The condenser design analysis shall include an analysis of the vent stream composition, constituent concentrations, flowrate, relative humidity, and temperature, and shall establish the design outlet organic compound concentration level, design average temperature of the condenser exhaust vent stream, and the design average temperatures of the coolant fluid at the condenser inlet and outlet. As an alternative to the condenser design analysis, an owner or operator may elect to use the procedures specified in paragraph (e)(5) of this section.

* * * * *

(5) As an alternative to the procedures in paragraph (e)(4)(i) of this section, an owner or operator may elect to use the procedures documented in the GRI report entitled, ''Atmospheric Rich/Lean Method for Determining Glycol Dehydrator Emissions'' (GRI–95/0368.1) as inputs for the model GRI–GLYCalc™, Version 3.0 or higher, to generate a condenser performance curve.

(f) *Compliance demonstration for control device performance requirements.* This paragraph applies to the demonstration of compliance with the control device performance requirements specified in § 63.771(d)(1)(i), (e)(3), and (f)(1). Compliance shall be demonstrated using the requirements in paragraphs (f)(1) through (3) of this section. As an alternative, an owner or operator that installs a condenser as the control device to achieve the requirements specified in § 63.771(d)(1)(ii), (e)(3), or (f)(1) may demonstrate compliance according to paragraph (g) of this section. An owner or operator may switch between compliance with paragraph (f) of this section and compliance with paragraph (g) of this section only after at least 1 year of operation in compliance with the selected approach. Notification of such a change in the compliance method shall be reported in the next Periodic Report, as required in § 63.775(e), following the change.

* * * * *

(2) The owner or operator shall calculate the daily average of the applicable monitored parameter in accordance with § 63.773(d)(4) except that the inlet gas flowrate to the control device shall not be averaged.

(3) Compliance with the operating parameter limit is achieved when the daily average of the monitoring parameter value calculated under paragraph (f)(2) of this section is either equal to or greater than the minimum or equal to or less than the maximum monitoring value established under paragraph (f)(1) of this section. For inlet gas flowrate, compliance with the operating parameter limit is achieved when the value is equal to or less than the value established under § 63.772(h) or under the performance test conducted under § 63.772(e), as applicable.

(4) Except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities (including, as applicable, system accuracy audits and required zero and span adjustments), the CMS required in § 63.773(d) must be operated at all times the affected source is operating. A monitoring system malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring system to provide valid data. Monitoring system failures that are caused in part by poor maintenance or careless operation are not malfunctions. Monitoring system repairs are required to be completed in response to monitoring system malfunctions and to return the monitoring system to operation as expeditiously as practicable.

(5) Data recorded during monitoring system malfunctions, repairs associated with monitoring system malfunctions, or required monitoring system quality assurance or control activities may not be used in calculations used to report emissions or operating levels. All the data collected during all other required data collection periods must be used in assessing the operation of the control device and associated control system.

(6) Except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required quality monitoring system quality assurance or quality control activities (including, as applicable, system accuracy audits and required zero and span adjustments), failure to collect required data is a deviation of the monitoring requirements.

(g) *Compliance demonstration with percent reduction or emission limit performance requirements—condensers.* This paragraph applies to the demonstration of compliance with the performance requirements specified in § 63.771(d)(1)(ii), (e)(3), or (f)(1) for condensers. Compliance shall be demonstrated using the procedures in paragraphs (g)(1) through (3) of this section.

(1) The owner or operator shall establish a site-specific condenser performance curve according to § 63.773(d)(5)(ii). For sources required to meet the BTEX limit in accordance with § 63.771(e) or (f)(1) the owner or operator shall identify the minimum percent reduction necessary to meet the BTEX limit.

(2) Compliance with the requirements in § 63.771(d)(1)(ii), (e)(3), or (f)(1) shall be demonstrated by the procedures in paragraphs (g)(2)(i) through (iii) of this section.

* * * * *

(iii) Except as provided in paragraphs (g)(2)(iii)(A) and (B) of this section, at the end of each operating day, the owner or operator shall calculate the 365-day average HAP, or BTEX, emission reduction, as appropriate, from the condenser efficiencies as determined in paragraph (g)(2)(ii) of this section for the preceding 365 operating days. If the owner or operator uses a combination of process modifications and a condenser in accordance with the requirements of § 63.771(e), the 365-day average HAP, or BTEX, emission reduction shall be calculated using the emission reduction achieved through process modifications and the condenser efficiency as determined in paragraph (g)(2)(ii) of this section, both for the previous 365 operating days.

(A) After the compliance dates specified in § 63.760(f), an owner or operator with less than 120 days of data for determining average HAP, or BTEX, emission reduction, as appropriate, shall calculate the average HAP, or BTEX emission reduction, as appropriate, for the first 120 days of operation after the compliance dates. For sources required to meet the overall 95.0 percent reduction requirement, compliance is achieved if the 120-day average HAP emission reduction is equal to or greater than 90.0 percent. For sources required to meet the BTEX limit under § 63.765(b)(1)(iii), compliance is achieved if the average BTEX emission reduction is at least 95.0 percent of the required 365-day value identified under paragraph (g)(1) of this section (*i.e.,* at least 76.0 percent if the 365-day design value is 80.0 percent).

(B) After 120 days and no more than 364 days of operation after the compliance dates specified in

§ 63.760(f), the owner or operator shall calculate the average HAP emission reduction as the HAP emission reduction averaged over the number of days between the current day and the applicable compliance date. For sources required to meet the overall 95.0-percent reduction requirement, compliance with the performance requirements is achieved if the average HAP emission reduction is equal to or greater than 90.0 percent. For sources required to meet the BTEX limit under § 63.765(b)(1)(iii), compliance is achieved if the average BTEX emission reduction is at least 95.0 percent of the required 365-day value identified under paragraph (g)(1) of this section (*i.e.,* at least 76.0 percent if the 365-day design value is 80.0 percent).

(3) If the owner or operator has data for 365 days or more of operation, compliance is achieved based on the applicable criteria in paragraphs (g)(3)(i) or (ii) of this section.

(i) For sources meeting the HAP emission reduction specified in § 63.771(d)(1)(ii) or (e)(3) the average HAP emission reduction calculated in paragraph (g)(2)(iii) of this section is equal to or greater than 95.0 percent.

(ii) For sources required to meet the BTEX limit under § 63.771(e)(3) or (f)(1), compliance is achieved if the average BTEX emission reduction calculated in paragraph (g)(2)(iii) of this section is equal to or greater than the minimum percent reduction identified in paragraph (g)(1) of this section.

(h) *Performance testing for combustion control devices—manufacturers' performance test.* (1) This paragraph applies to the performance testing of a combustion control device conducted by the device manufacturer. The manufacturer shall demonstrate that a specific model of control device achieves the performance requirements in paragraph (h)(7) of this section by conducting a performance test as specified in paragraphs (h)(2) through (6) of this section.

(2) Performance testing shall consist of three one-hour (or longer) test runs for each of the four following firing rate settings making a total of 12 test runs per test. Propene (propylene) gas shall be used for the testing fuel. All fuel analyses shall be performed by an independent third-party laboratory (not affiliated with the control device manufacturer or fuel supplier).

(i) 90–100 percent of maximum design rate (fixed rate).

(ii) 70–100–70 percent (ramp up, ramp down). Begin the test at 70 percent of the maximum design rate. During the first 5 minutes, incrementally ramp the firing rate to 100 percent of the maximum design rate. Hold at 100 percent for 5 minutes. In the 10–15 minute time range, incrementally ramp back down to 70 percent of the maximum design rate. Repeat three more times for a total of 60 minutes of sampling.

(iii) 30–70–30 percent (ramp up, ramp down). Begin the test at 30 percent of the maximum design rate. During the first 5 minutes, incrementally ramp the firing rate to 70 percent of the maximum design rate. Hold at 70 percent for 5 minutes. In the 10–15 minute time range, incrementally ramp back down to 30 percent of the maximum design rate. Repeat three more times for a total of 60 minutes of sampling.

(iv) 0–30–0 percent (ramp up, ramp down). Begin the test at 0 percent of the maximum design rate. During the first 5 minutes, incrementally ramp the firing rate to 30 percent of the maximum design rate. Hold at 30 percent for 5 minutes. In the 10–15 minute time range, incrementally ramp back down to 0 percent of the maximum design rate. Repeat three more times for a total of 60 minutes of sampling.

(3) All models employing multiple enclosures shall be tested simultaneously and with all burners operational. Results shall be reported for the each enclosure individually and for the average of the emissions from all interconnected combustion enclosures/chambers. Control device operating data shall be collected continuously throughout the performance test using an electronic Data Acquisition System and strip chart. Data shall be submitted with the test report in accordance with paragraph (h)(8)(iii) of this section.

(4) Inlet gas testing shall be conducted as specified in paragraphs (h)(4)(i) through (iii) of this section.

(i) The inlet gas flow metering system shall be located in accordance with Method 2A, 40 CFR part 60, appendix A–1, (or other approved procedure) to measure inlet gas flowrate at the control device inlet location. The fitting for filling inlet gas sample containers shall be located a minimum of 8 pipe diameters upstream of any inlet gas flow monitoring meter.

(ii) Inlet gas flowrate shall be determined using Method 2A, 40 CFR part 60, appendix A–1. Record the start and stop reading for each 60-minute THC test. Record the inlet gas pressure and temperature at 5-minute intervals throughout each 60-minute THC test.

(iii) Inlet gas fuel sampling shall be conducted in accordance with the criteria in paragraphs (h)(4)(iii)(A) and (B) of this section.

(A) At the inlet gas sampling location, securely connect a Silonite-coated stainless steel evacuated canister fitted with a flow controller sufficient to fill the canister over a 3 hour period. Filling shall be conducted as specified in the following:

(*1*) Open the canister sampling valve at the beginning of the total hydrocarbon (THC) test, and close the canister at the end of each THC run.

(*2*) Fill one canister across the three test runs for each THC test such that one composite fuel sample exists for each test condition.

(*3*) Label the canisters individually and record on a chain of custody form.

(B) Each inlet gas sample shall be analyzed using the following methods. The results shall be included in the test report.

(*1*) Hydrocarbon compounds containing between one and five atoms of carbon plus benzene using ASTM D1945–03 (Reapproved 2010) (incorporated by reference as specified in § 63.14).

(*2*) Hydrogen (H_2), carbon monoxide (CO), carbon dioxide (CO_2), nitrogen (N_2), oxygen (O_2) using ASTM D1945–03 (Reapproved 2010) (incorporated by reference as specified in § 63.14).

(*3*) Higher heating value using ASTM D3588–98 (Reapproved 2003) or ASTM D4891–89 (Reapproved 2006) (incorporated by reference as specified in § 63.14).

(5) Outlet testing shall be conducted in accordance with the criteria in paragraphs (h)(5)(i) through (v) of this section.

(i) Sampling and flowrate measured in accordance with the following:

(A) The outlet sampling location shall be a minimum of 4 equivalent stack diameters downstream from the highest peak flame or any other flow disturbance, and a minimum of one equivalent stack diameter upstream of the exit or any other flow disturbance. A minimum of two sample ports shall be used.

(B) Flowrate shall be measured using Method 1, 40 CFR part 60, Appendix 1, for determining flow measurement traverse point location; and Method 2, 40 CFR part 60, Appendix 1, shall be used to measure duct velocity. If low flow conditions are encountered (*i.e.,* velocity pressure differentials less than 0.05 inches of water) during the performance test, a more sensitive manometer or other pressure measurement device shall be used to obtain an accurate flow profile.

(ii) Molecular weight shall be determined as specified in paragraphs (h)(4)(iii)(B) and (h)(5)(ii)(A) and (B) of this section.

(A) An integrated bag sample shall be collected during the Method 4, 40 CFR

part 60, Appendix A, moisture test. Analyze the bag sample using a gas chromatograph-thermal conductivity detector (GC–TCD) analysis meeting the following criteria:

(*1*) Collect the integrated sample throughout the entire test, and collect representative volumes from each traverse location.

(*2*) The sampling line shall be purged with stack gas before opening the valve and beginning to fill the bag.

(*3*) The bag contents shall be vigorously mixed prior to the GC analysis.

(*4*) The GC–TCD calibration procedure in Method 3C, 40 CFR part 60, Appendix A, shall be modified by using EPAAlt–045 as follows: For the initial calibration, triplicate injections of any single concentration must agree within 5 percent of their mean to be valid. The calibration response factor for a single concentration re-check must be within 10 percent of the original calibration response factor for that concentration. If this criterion is not met, the initial calibration using at least three concentration levels shall be repeated.

(B) Report the molecular weight of: O_2, CO_2, methane (CH4), and N_2 and include in the test report submitted under § 63.775(d)(iii). Moisture shall be determined using Method 4, 40 CFR part 60, Appendix A. Traverse both ports with the Method 4, 40 CFR part 60, Appendix A, sampling train during each test run. Ambient air shall not be introduced into the Method 3C, 40 CFR part 60, Appendix A, integrated bag sample during the port change.

(iii) Carbon monoxide shall be determined using Method 10, 40 CFR part 60, Appendix A, or ASTM D6522–00 (Reapproved 2005), (incorporated by reference as specified in § 63.14). The test shall be run at the same time and with the sample points used for the EPA Method 25A, 40 CFR part 60, Appendix A, testing. An instrument range of 0–10 per million by volume-dry (ppmvd) shall be used.

(iv) Visible emissions shall be determined using Method 22, 40 CFR part 60, Appendix A. The test shall be performed continuously during each test run. A digital color photograph of the exhaust point, taken from the position of the observer and annotated with date and time, will be taken once per test run and the four photos included in the test report.

(v) Excess air shall be determined using resultant data from the EPA Method 3C tests and EPA Method 3B, 40 CFR part 60, Appendix A, equation 3B–1 or ANSI/ASME PTC 19.10, 1981-Part 10 (manual portion only) (incorporated by reference as specified in § 63.14).

(6) Total hydrocarbons (THC) shall be determined as specified by the following criteria:

(i) Conduct THC sampling using Method 25A, 40 CFR part 60, Appendix A, except the option for locating the probe in the center 10 percent of the stack shall not be allowed. The THC probe must be traversed to 16.7 percent, 50 percent, and 83.3 percent of the stack diameter during each test.

(ii) A valid test shall consist of three Method 25A, 40 CFR part 60, Appendix A, tests, each no less than 60 minutes in duration.

(iii) A 0–10 parts per million by volume-wet (ppmvw) (as propane) measurement range is preferred; as an alternative a 0–30 ppmvw (as carbon) measurement range may be used.

(iv) Calibration gases will be propane in air and be certified through EPA Protocol 1—''EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards,'' September 1997, as amended August 25, 1999, EPA–600/R–97/121 (or more recent if updated since 1999).

(v) THC measurements shall be reported in terms of ppmvw as propane.

(vi) THC results shall be corrected to 3 percent CO_2, as measured by Method 3C, 40 CFR part 60, Appendix A.

(vii) Subtraction of methane/ethane from the THC data is not allowed in determining results.

(7) Performance test criteria:

(i) The control device model tested must meet the criteria in paragraphs (h)(7)(i)(A) through (C) of this section:

(A) Method 22, 40 CFR part 60, Appendix A, results under paragraph (h)(5)(v) of this section with no indication of visible emissions, and

(B) Average Method 25A, 40 CFR part 60, Appendix A, results under paragraph (h)(6) of this section equal to or less than 10.0 ppmvw THC as propane corrected to 3.0 percent CO_2, and

(C) Average CO emissions determined under paragraph (h)(5)(iv) of this section equal to or less than 10 parts ppmvd, corrected to 3.0 percent CO_2.

(D) Excess combustion air shall be equal to or greater than 150 percent.

(ii) The manufacturer shall determine a maximum inlet gas flowrate which shall not be exceeded for each control device model to achieve the criteria in paragraph (h)(7)(i) of this section.

(iii) A control device meeting the criteria in paragraphs (h)(7)(i)(A) through (C) of this section will have demonstrated a destruction efficiency of 95.0 percent for HAP regulated under this subpart.

(8) The owner or operator of a combustion control device model tested under this section shall submit the information listed in paragraphs (h)(8)(i) through (iii) of this section in the test report required under § 63.775(d)(1)(iii).

(i) Full schematic of the control device and dimensions of the device components.

(ii) Design net heating value (minimum and maximum) of the device.

(iii) Test fuel gas flow range (in both mass and volume). Include the minimum and maximum allowable inlet gas flowrate.

(iv) Air/stream injection/assist ranges, if used.

(v) The test parameter ranges listed in paragraphs (h)(8)(v)(A) through (O) of this section, as applicable for the tested model.

(A) Fuel gas delivery pressure and temperature.

(B) Fuel gas moisture range.

(C) Purge gas usage range.

(D) Condensate (liquid fuel) separation range.

(E) Combustion zone temperature range. This is required for all devices that measure this parameter.

(F) Excess combustion air range.

(G) Flame arrestor(s).

(H) Burner manifold pressure.

(I) Pilot flame sensor.

(J) Pilot flame design fuel and fuel usage.

(K) Tip velocity range.

(L) Momentum flux ratio.

(M) Exit temperature range.

(N) Exit flowrate.

(O) Wind velocity and direction.

(vi) The test report shall include all calibration quality assurance/quality control data, calibration gas values, gas cylinder certification, and strip charts annotated with test times and calibration values.

(i) *Compliance demonstration for combustion control devices—manufacturers' performance test.* This paragraph applies to the demonstration of compliance for a combustion control device tested under the provisions in paragraph (h) of this section. Owners or operators shall demonstrate that a control device achieves the performance requirements of § 63.771(d)(1), (e)(3)(ii) or (f)(1), by installing a device tested under paragraph (h) of this section and complying with the following criteria:

(1) The inlet gas flowrate shall meet the range specified by the manufacturer. Flowrate shall be calculated as specified in § 63.773(d)(3)(i)(H)(*1*).

(2) A pilot flame shall be present at all times of operation. The pilot flame shall be monitored in accordance with § 63.773(d)(3)(i)(H)(*2*).

(3) Devices shall be operated with no visible emissions, except for periods not

to exceed a total of 2 minutes during any hour. A visible emissions test using Method 22, 40 CFR part 60, Appendix A, shall be performed each calendar quarter. The observation period shall be 1 hour and shall be conducted according to EPA Method 22, 40 CFR part 60, Appendix A.

(4) Compliance with the operating parameter limit is achieved when the following criteria are met:

(i) The inlet gas flowrate monitored under paragraph (i)(1) of this section is equal to or below the maximum established by the manufacturer; and

(ii) The pilot flame is present at all times; and

(iii) During the visible emissions test performed under paragraph (i)(3) of this section the duration of visible emissions does not exceed a total of 2 minutes during the observation period. Devices failing the visible emissions test shall follow manufacturers repair instructions, if available, or best combustion engineering practice as outlined in the unit inspection and maintenance plan, to return the unit to compliant operation. All repairs and maintenance activities for each unit shall be recorded in a maintenance and repair log and shall be available on site for inspection.

(iv) Following return to operation from maintenance or repair activity, each device must pass a Method 22 visual observation as described in paragraph (i)(3) of this section.

■ 19. Section 63.773 is amended by:
■ a. Adding paragraph (b);
■ b. Revising paragraph (d)(1) introductory text;
■ c. Revising paragraph (d)(1)(ii) and adding paragraphs (d)(1)(iii) and (iv);
■ d. Revising paragraph (d)(2);
■ e. Revising paragraph (d)(3)(i)(A);
■ f. Revising paragraph (d)(3)(i)(D);
■ g. Revising paragraph (d)(3)(i)(G);
■ h. Adding paragraph (d)(3)(i)(H);
■ i. Revising paragraph (d)(4);
■ j. Revising paragraph (d)(5)(i);
■ k. Revising paragraphs (d)(5)(ii)(A) through (C);
■ l. Revising paragraph (d)(6) introductory text;
■ m. Revising paragraphs (d)(6)(ii) and (iii);
■ n. Adding paragraph (d)(6)(vi);
■ o. Revising paragraph (d)(7); and
■ p. Removing paragraphs (d)(8) and (9).

The revisions and additions read as follows:

§ 63.773 Inspection and monitoring requirements.

* * * * *

(b) The owner or operator of a control device whose model was tested under § 63.772(h) shall develop an inspection and maintenance plan for each control device. At a minimum, the plan shall contain the control device manufacturer's recommendations for ensuring proper operation of the device. Semi-annual inspections shall be conducted for each control device with maintenance and replacement of control device components made in accordance with the plan.

* * * * *

(d) *Control device monitoring requirements.* (1) For each control device, except as provided for in paragraph (d)(2) of this section, the owner or operator shall install and operate a continuous parameter monitoring system in accordance with the requirements of paragraphs (d)(3) through (7) of this section. Owners or operators that install and operate a flare in accordance with § 63.771(d)(1)(iii) or (f)(1)(iii) are exempt from the requirements of paragraphs (d)(4) and (5) of this section. The continuous monitoring system shall be designed and operated so that a determination can be made on whether the control device is achieving the applicable performance requirements of § 63.771(d), (e)(3), or (f)(1). Each continuous parameter monitoring system shall meet the following specifications and requirements:

* * * * *

(ii) A site-specific monitoring plan must be prepared that addresses the monitoring system design, data collection, and the quality assurance and quality control elements outlined in paragraph (d) of this section and in § 63.8(d). Each CPMS must be installed, calibrated, operated, and maintained in accordance with the procedures in your approved site-specific monitoring plan. Using the process described in § 63.8(f)(4), you may request approval of monitoring system quality assurance and quality control procedures alternative to those specified in paragraphs (d)(1)(ii)(A) through (E) of this section in your site-specific monitoring plan.

(A) The performance criteria and design specifications for the monitoring system equipment, including the sample interface, detector signal analyzer, and data acquisition and calculations;

(B) Sampling interface (*e.g.*, thermocouple) location such that the monitoring system will provide representative measurements;

(C) Equipment performance checks, system accuracy audits, or other audit procedures;

(D) Ongoing operation and maintenance procedures in accordance with provisions in § 63.8(c)(1) and (3); and

(E) Ongoing reporting and recordkeeping procedures in accordance with provisions in § 63.10(c), (e)(1), and (e)(2)(i).

(iii) The owner or operator must conduct the CPMS equipment performance checks, system accuracy audits, or other audit procedures specified in the site-specific monitoring plan at least once every 12 months.

(iv) The owner or operator must conduct a performance evaluation of each CPMS in accordance with the site-specific monitoring plan.

(2) An owner or operator is exempt from the monitoring requirements specified in paragraphs (d)(3) through (7) of this section for the following types of control devices:

(i) Except for control devices for small glycol dehydration units, a boiler or process heater in which all vent streams are introduced with the primary fuel or is used as the primary fuel; or

(ii) Except for control devices for small glycol dehydration units, a boiler or process heater with a design heat input capacity equal to or greater than 44 megawatts.

(3) * * *

(i) * * *

(A) For a thermal vapor incinerator that demonstrates during the performance test conducted under § 63.772(e) that the combustion zone temperature is an accurate indicator of performance, a temperature monitoring device equipped with a continuous recorder. The monitoring device shall have a minimum accuracy of ±2 percent of the temperature being monitored in °C, or ±2.5 °C, whichever value is greater. The temperature sensor shall be installed at a location representative of the combustion zone temperature.

* * * * *

(D) For a boiler or process heater, a temperature monitoring device equipped with a continuous recorder. The temperature monitoring device shall have a minimum accuracy of ±2 percent of the temperature being monitored in °C, or ±2.5 °C, whichever value is greater. The temperature sensor shall be installed at a location representative of the combustion zone temperature.

* * * * *

(G) For a nonregenerative-type carbon adsorption system, the owner or operator shall monitor the design carbon replacement interval established using a performance test performed in accordance with § 63.772(e)(3) and shall be based on the total carbon working capacity of the control device and source operating schedule.

(H) For a control device model whose model is tested under § 63.772(h):

(*1*) The owner or operator shall determine actual average inlet waste gas flowrate using the model GRI–GLYCalc ™, Version 3.0 or higher, ProMax, or AspenTech HYSYS. Inputs to the models shall be representative of actual operating conditions of the controlled unit. The determination shall be performed to coincide with the visible emissions test under § 63.772(i)(3);

(*2*) A heat sensing monitoring device equipped with a continuous recorder that indicates the continuous ignition of the pilot flame.

* * * * *

(4) Using the data recorded by the monitoring system, except for inlet gas flowrate, the owner or operator must calculate the daily average value for each monitored operating parameter for each operating day. If the emissions unit operation is continuous, the operating day is a 24-hour period. If the emissions unit operation is not continuous, the operating day is the total number of hours of control device operation per 24-hour period. Valid data points must be available for 75 percent of the operating hours in an operating day to compute the daily average.

(5) * * *

(i) The owner or operator shall establish a minimum operating parameter value or a maximum operating parameter value, as appropriate for the control device, to define the conditions at which the control device must be operated to continuously achieve the applicable performance requirements of § 63.771(d)(1), (e)(3)(ii), or (f)(1). Each minimum or maximum operating parameter value shall be established as follows:

(A) If the owner or operator conducts performance tests in accordance with the requirements of § 63.772(e)(3) to demonstrate that the control device achieves the applicable performance requirements specified in § 63.771(d)(1), (e)(3)(ii) or (f)(1), then the minimum operating parameter value or the maximum operating parameter value shall be established based on values measured during the performance test and supplemented, as necessary, by a condenser design analysis or control device manufacturer recommendations or a combination of both.

(B) If the owner or operator uses a condenser design analysis in accordance with the requirements of § 63.772(e)(4) to demonstrate that the control device achieves the applicable performance requirements specified in § 63.771(d)(1), (e)(3)(ii), or (f)(1), then the minimum operating parameter value or the maximum operating parameter value shall be established based on the condenser design analysis and may be supplemented by the condenser manufacturer's recommendations.

(C) If the owner or operator operates a control device where the performance test requirement was met under § 63.772(h) to demonstrate that the control device achieves the applicable performance requirements specified in § 63.771(d)(1), (e)(3)(ii), or (f)(1), then the maximum inlet gas flowrate shall be established based on the performance test and supplemented, as necessary, by the manufacturer recommendations.

(ii) * * *

(A) If the owner or operator conducts a performance test in accordance with the requirements of § 63.772(e)(3) to demonstrate that the condenser achieves the applicable performance requirements in § 63.771(d)(1), (e)(3)(ii), or (f)(1), then the condenser performance curve shall be based on values measured during the performance test and supplemented as necessary by control device design analysis, or control device manufacturer's recommendations, or a combination of both.

(B) If the owner or operator uses a control device design analysis in accordance with the requirements of § 63.772(e)(4)(i) to demonstrate that the condenser achieves the applicable performance requirements specified in § 63.771(d)(1), (e)(3)(ii), or (f)(1), then the condenser performance curve shall be based on the condenser design analysis and may be supplemented by the control device manufacturer's recommendations.

(C) As an alternative to paragraph (d)(5)(ii)(B) of this section, the owner or operator may elect to use the procedures documented in the GRI report entitled, "Atmospheric Rich/Lean Method for Determining Glycol Dehydrator Emissions" (GRI–95/0368.1) as inputs for the model GRI–GLYCalc ™, Version 3.0 or higher, to generate a condenser performance curve.

(6) An excursion for a given control device is determined to have occurred when the monitoring data or lack of monitoring data result in any one of the criteria specified in paragraphs (d)(6)(i) through (vi) of this section being met. When multiple operating parameters are monitored for the same control device and during the same operating day and more than one of these operating parameters meets an excursion criterion specified in paragraphs (d)(6)(i) through (vi) of this section, then a single excursion is determined to have occurred for the control device for that operating day.

* * * * *

(ii) For sources meeting § 63.771(d)(1)(ii), an excursion occurs when the 365-day average condenser efficiency calculated according to the requirements specified in § 63.772(g)(2)(iii) is less than 95.0 percent. For sources meeting § 63.771(f)(1), an excursion occurs when the 365-day average condenser efficiency calculated according to the requirements specified in § 63.772(g)(2)(iii) is less than 95.0 percent of the identified 365-day required percent reduction.

(iii) For sources meeting § 63.771(d)(1)(ii), if an owner or operator has less than 365 days of data, an excursion occurs when the average condenser efficiency calculated according to the procedures specified in § 63.772(g)(2)(iii)(A) or (B) is less than 90.0 percent. For sources meeting § 63.771(f)(1), an excursion occurs when the 365-day average condenser efficiency calculated according to the requirements specified in § 63.772(g)(2)(iii) is less than the identified 365-day required percent reduction.

* * * * *

(vi) For control device whose model is tested under § 63.772(h) an excursion occurs when:

(A) The inlet gas flowrate exceeds the maximum established during the test conducted under § 63.772(h).

(B) Failure of the quarterly visible emissions test conducted under § 63.772(i)(3) occurs.

(7) For each excursion, the owner or operator shall be deemed to have failed to have applied control in a manner that achieves the required operating parameter limits. Failure to achieve the required operating parameter limits is a violation of this standard.

* * * * *

■ 20. Section 63.774 is amended by:
■ a. Revising paragraph (b)(3) introductory text;
■ b. Removing and reserving paragraph (b)(3)(ii);
■ c. Revising paragraph (b)(4)(ii) introductory text;
■ d. Adding paragraph (b)(4)(ii)(C);
■ e. Revising paragraph (b)(4)(iii);
■ f. Adding paragraph (b)(7)(ix); and
■ g. Adding paragraphs (g) through (i).

The revisions and additions read as follows:

§ 63.774 Recordkeeping requirements.

* * * * *

(b) * * *

(3) Records specified in § 63.10(c) for each monitoring system operated by the

owner or operator in accordance with the requirements of § 63.773(d). Notwithstanding the requirements of § 63.10(c), monitoring data recorded during periods identified in paragraphs (b)(3)(i) through (iv) of this section shall not be included in any average or percent leak rate computed under this subpart. Records shall be kept of the times and durations of all such periods and any other periods during process or control device operation when monitors are not operating or failed to collect required data.

* * * * *

(4) * * *

(ii) Records of the daily average value of each continuously monitored parameter for each operating day determined according to the procedures specified in § 63.773(d)(4) of this subpart, except as specified in paragraphs (b)(4)(ii)(A) through (C) of this section.

* * * * *

(C) For a control device whose model is tested under § 63.772(h), the records required in paragraph (h) of this section.

(iii) Hourly records of the times and durations of all periods when the vent stream is diverted from the control device or the device is not operating.

* * * * *

(7) * * *

(ix) Records identifying the carbon replacement schedule under § 63.771(d)(5) and records of each carbon replacement.

* * * * *

(g) The owner or operator of an affected source subject to this subpart shall maintain records of the occurrence and duration of each malfunction of operation (*i.e.,* process equipment) or the air pollution control equipment and monitoring equipment. The owner or operator shall maintain records of actions taken during periods of malfunction to minimize emissions in accordance with § 63.764(j), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation.

(h) Record the following when using a control device whose model is tested under § 63.772(h) to comply with § 63.771(d), (e)(3)(ii), and (f)(1):

(1) All visible emission readings and flowrate calculations made during the compliance determination required by § 63.772(i); and

(2) All hourly records and other recorded periods when the pilot flame is absent.

(i) The date the semi-annual maintenance inspection required under § 63.773(b) is performed. Include a list of any modifications or repairs made to the control device during the inspection and other maintenance performed such as cleaning of the fuel nozzles.

■ 21. Section 63.775 is amended by:
■ a. Revising paragraph (b)(1);
■ b. Revising paragraph (b)(6);
■ c. Removing and reserving paragraph (b)(7);
■ d. Revising paragraph (c)(1);
■ e. Revising paragraph (c)(6);
■ f. Revising paragraph (c)(7)(i);
■ g. Revising paragraph (d)(1)(i);
■ h. Revising paragraph (d)(1)(ii) introductory text;
■ i. Revising paragraph (d)(5)(ii);
■ j. Adding paragraph (d)(5)(iv);
■ k. Revising paragraph (d)(11);
■ l. Adding paragraphs (d)(13) and (d)(14);
■ m. Revising paragraphs (e)(2) introductory text, (e)(2)(ii)(B) and (C);
■ n. Adding paragraphs (e)(2)(ii)(E) and (F);
■ o. Adding paragraphs (e)(2)(xi) through (xiv); and
■ p. Adding paragraph (g).

The revisions and additions read as follows:

§ 63.775 Reporting requirements.

* * * * *

(b) * * *

(1) The initial notifications required for existing affected sources under § 63.9(b)(2) shall be submitted as provided in paragraphs (b)(1)(i) and (ii) of this section.

(i) Except as otherwise provided in paragraph (b)(1)(ii) of this section, the initial notifications shall be submitted by 1 year after an affected source becomes subject to the provisions of this subpart or by June 17, 2000, whichever is later. Affected sources that are major sources on or before June 17, 2000, and plan to be area sources by June 17, 2002, shall include in this notification a brief, nonbinding description of a schedule for the action(s) that are planned to achieve area source status.

(ii) An affected source identified under § 63.760(f)(7) or (9) shall submit an initial notification required for existing affected sources under § 63.9(b)(2) within 1 year after the affected source becomes subject to the provisions of this subpart or by October 15, 2013, whichever is later. An affected source identified under § 63.760(f)(7) or (9) that plans to be an area source by October 15, 2015, shall include in this notification a brief, nonbinding description of a schedule for the action(s) that are planned to achieve area source status.

* * * * *

(6) If there was a malfunction during the reporting period, the Periodic Report specified in paragraph (e) of this section shall include the number, duration, and a brief description for each type of malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded. The report must also include a description of actions taken by an owner or operator during a malfunction of an affected source to minimize emissions in accordance with § 63.764(j), including actions taken to correct a malfunction.

* * * * *

(c) * * *

(1) The initial notifications required under § 63.9(b)(2) not later than January 3, 2008. In addition to submitting your initial notification to the addressees specified under § 63.9(a), you must also submit a copy of the initial notification to the EPA's Office of Air Quality Planning and Standards. Send your notification via email to *Oil and Gas Sector@epa.gov* or via U.S. mail or other mail delivery service to U.S. EPA, Sector Policies and Programs Division/ Fuels and Incineration Group (E143–01), Attn: Oil and Gas Project Leader, Research Triangle Park, NC 27711.

* * * * *

(6) If there was a malfunction during the reporting period, the Periodic Report specified in paragraph (e) of this section shall include the number, duration, and a brief description for each type of malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded. The report must also include a description of actions taken by an owner or operator during a malfunction of an affected source to minimize emissions in accordance with § 63.764(j), including actions taken to correct a malfunction.

(7) * * *

(i) Documentation of the source's location relative to the nearest UA plus offset and UC boundaries. This information shall include the latitude and longitude of the affected source; whether the source is located in an urban cluster with 10,000 people or more; the distance in miles to the nearest urbanized area boundary if the source is not located in an urban cluster with 10,000 people or more; and the name of the nearest urban cluster with 10,000 people or more and nearest urbanized area.

* * * * *

(d) * * *

(1) * * *

(i) The condenser design analysis documentation specified in

§ 63.772(e)(4) of this subpart, if the owner or operator elects to prepare a design analysis.

(ii) If the owner or operator is required to conduct a performance test, the performance test results including the information specified in paragraphs (d)(1)(ii)(A) and (B) of this section. Results of a performance test conducted prior to the compliance date of this subpart can be used provided that the test was conducted using the methods specified in § 63.772(e)(3) and that the test conditions are representative of current operating conditions. If the owner or operator operates a combustion control device model tested under § 63.772(h), an electronic copy of the performance test results shall be submitted via email to *Oil_and_Gas_PT@EPA.GOV* unless the test results for that model of combustion control device are posted at the following Web site: *epa.gov/airquality/oilandgas/*.

* * * * *

(5) * * *

(ii) An explanation of the rationale for why the owner or operator selected each of the operating parameter values established in § 63.773(d)(5). This explanation shall include any data and calculations used to develop the value and a description of why the chosen value indicates that the control device is operating in accordance with the applicable requirements of § 63.771(d)(1), (e)(3)(ii) or (f)(1).

* * * * *

(iv) For each carbon adsorber, the predetermined carbon replacement schedule as required in § 63.771(d)(5)(i).

* * * * *

(11) The owner or operator shall submit the analysis prepared under § 63.771(e)(2) to demonstrate the conditions by which the facility will be operated to achieve the HAP emission reduction of 95.0 percent, or the BTEX limit in § 63.765(b)(1)(iii), through process modifications or a combination of process modifications and one or more control devices.

* * * * *

(13) If the owner or operator installs a combustion control device model tested under the procedures in § 63.772(h), the data listed under § 63.772(h)(8).

(14) For each combustion control device model tested under § 63.772(h), the information listed in paragraphs (d)(14)(i) through (vi) of this section.

(i) Name, address and telephone number of the control device manufacturer.

(ii) Control device model number.

(iii) Control device serial number.

(iv) Date the model of control device was tested by the manufacturer.

(v) Manufacturer's HAP destruction efficiency rating.

(vi) Control device operating parameters, maximum allowable inlet gas flowrate.

(e) * * *

(2) The owner or operator shall include the information specified in paragraphs (e)(2)(i) through (ix) of this section, as applicable.

* * * * *

(ii) * * *

(B) For each excursion caused when the 365-day average condenser control efficiency is less than the value specified in § 63.773(d)(6)(ii), the report must include the 365-day average values of the condenser control efficiency, and the date and duration of the period that the excursion occurred.

(C) For each excursion caused when condenser control efficiency is less than the value specified in § 63.773(d)(6)(iii), the report must include the average values of the condenser control efficiency, and the date and duration of the period that the excursion occurred.

* * * * *

(E) For each excursion caused when the maximum inlet gas flowrate identified under § 63.772(h) is exceeded, the report must include the values of the inlet gas identified and the date and duration of the period that the excursion occurred.

(F) For each excursion caused when visible emissions determined under § 63.772(i) exceed the maximum allowable duration, the report must include the date and duration of the period that the excursion occurred, repairs affected to the unit, and date the unit was returned to service.

* * * * *

(xi) The results of any periodic test as required in § 63.772(e)(3) conducted during the reporting period.

(xii) For each carbon adsorber used to meet the control device requirements of § 63.771(d)(1), records of each carbon replacement that occurred during the reporting period.

(xiii) For combustion control device inspections conducted in accordance with § 63.773(b) the records specified in § 63.774(i).

(xiv) Certification by a responsible official of truth, accuracy, and completeness. This certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

* * * * *

(g) *Electronic reporting.* (1) Within 60 days after the date of completing each performance test (defined in § 63.2) as required by this subpart you must submit the results of the performance tests required by this subpart to EPA's WebFIRE database by using the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (*www.epa.gov/cdx*). Performance test data must be submitted in the file format generated through use of EPA's Electronic Reporting Tool (ERT) (see *http://www.epa.gov/ttn/chief/ert/index.html*). Only data collected using test methods on the ERT Web site are subject to this requirement for submitting reports electronically to WebFIRE. Owners or operators who claim that some of the information being submitted for performance tests is confidential business information (CBI) must submit a complete ERT file including information claimed to be CBI on a compact disk or other commonly used electronic storage media (including, but not limited to, flash drives) to EPA. The electronic media must be clearly marked as CBI and mailed to U.S. EPA/OAPQS/CORE CBI Office, Attention: WebFIRE Administrator, MD C404–02, 4930 Old Page Rd., Durham, NC 27703. The same ERT file with the CBI omitted must be submitted to EPA via CDX as described earlier in this paragraph. At the discretion of the delegated authority, you must also submit these reports, including the confidential business information, to the delegated authority in the format specified by the delegated authority.

(2) All reports required by this subpart not subject to the requirements in paragraph (g)(1) of this section must be sent to the Administrator at the appropriate address listed in § 63.13. The Administrator or the delegated authority may request a report in any form suitable for the specific case (*e.g.*, by commonly used electronic media such as Excel spreadsheet, on CD or hard copy). The Administrator retains the right to require submittal of reports subject to paragraph (g)(1) of this section in paper format.

■ 22. Appendix to subpart HH of part 63 is amended by revising Table 2 to read as follows:

Appendix to Subpart HH of Part 63—Tables

* * * * *

TABLE 2 TO SUBPART HH OF PART 63—APPLICABILITY OF 40 CFR PART 63 GENERAL PROVISIONS TO SUBPART HH

General provisions reference	Applicable to subpart HH	Explanation
§ 63.1(a)(1)	Yes.	
§ 63.1(a)(2)	Yes.	
§ 63.1(a)(3)	Yes.	
§ 63.1(a)(4)	Yes.	
§ 63.1(a)(5)	No	Section reserved.
§ 63.1(a)(6)	Yes.	
§ 63.1(a)(7) through (a)(9)	No	Section reserved.
§ 63.1(a)(10)	Yes.	
§ 63.1(a)(11)	Yes.	
§ 63.1(a)(12)	Yes.	
§ 63.1(b)(1)	No	Subpart HH specifies applicability.
§ 63.1(b)(2)	No	Section reserved.
§ 63.1(b)(3)	Yes.	
§ 63.1(c)(1)	No	Subpart HH specifies applicability.
§ 63.1(c)(2)	Yes	Subpart HH exempts area sources from the requirement to obtain a Title V permit unless otherwise required by law as specified in § 63.760(h).
§ 63.1(c)(3) and (c)(4)	No	Section reserved.
§ 63.1(c)(5)	Yes.	
§ 63.1(d)	No	Section reserved.
§ 63.1(e)	Yes.	
§ 63.2	Yes	Except definition of major source is unique for this source category and there are additional definitions in subpart HH.
§ 63.3(a) through (c)	Yes.	
§ 63.4(a)(1) through (a)(2)	Yes.	
§ 63.4(a)(3) through (a)(5)	No	Section reserved.
§ 63.4(b)	Yes.	
§ 63.4(c)	Yes.	
§ 63.5(a)(1)	Yes.	
§ 63.5(a)(2)	Yes.	
§ 63.5(b)(1)	Yes.	
§ 63.5(b)(2)	No	Section reserved.
§ 63.5(b)(3)	Yes.	
§ 63.5(b)(4)	Yes.	
§ 63.5(b)(5)	No	Section Reserved.
§ 63.5(b)(6)	Yes.	
§ 63.5(c)	No	Section reserved.
§ 63.5(d)(1)	Yes.	
§ 63.5(d)(2)	Yes.	
§ 63.5(d)(3)	Yes.	
§ 63.5(d)(4)	Yes.	
§ 63.5(e)	Yes.	
§ 63.5(f)(1)	Yes.	
§ 63.5(f)(2)	Yes.	
§ 63.6(a)	Yes.	
§ 63.6(b)(1)	Yes.	
§ 63.6(b)(2)	Yes.	
§ 63.6(b)(3)	Yes.	
§ 63.6(b)(4)	Yes.	
§ 63.6(b)(5)	Yes.	
§ 63.6(b)(6)	No	Section reserved.
§ 63.6(b)(7)	Yes.	
§ 63.6(c)(1)	Yes.	
§ 63.6(c)(2)	Yes.	
§ 63.6(c)(3) through (c)(4)	No	Section reserved.
§ 63.6(c)(5)	Yes.	
§ 63.6(d)	No	Section reserved.
§ 63.6(e)(1)(i)	No	See § 63.764(j) for general duty requirement.
§ 63.6(e)(1)(ii)	No.	
§ 63.6(e)(1)(iii)	Yes.	
§ 63.6(e)(2)	No	Section reserved.
§ 63.6(e)(3)	No.	
§ 63.6(f)(1)	No.	
§ 63.6(f)(2)	Yes.	
§ 63.6(f)(3)	Yes.	
§ 63.6(g)	Yes.	
§ 63.6(h)(1)	No.	
§ 63.6(h)(2) through (h)(9)	Yes.	
§ 63.6(i)(1) through (i)(14)	Yes.	
§ 63.6(i)(15)	No	Section reserved.
§ 63.6(i)(16)	Yes.	
§ 63.6(j)	Yes.	

TABLE 2 TO SUBPART HH OF PART 63—APPLICABILITY OF 40 CFR PART 63 GENERAL PROVISIONS TO SUBPART HH—Continued

General provisions reference	Applicable to subpart HH	Explanation
§ 63.7(a)(1)	Yes.	
§ 63.7(a)(2)	Yes	But the performance test results must be submitted within 180 days after the compliance date.
§ 63.7(a)(3)	Yes.	
§ 63.7(a)(4)	Yes.	
§ 63.7(c)	Yes.	
§ 63.7(d)	Yes.	
§ 63.7(e)(1)	No.	
§ 63.7(e)(2)	Yes.	
§ 63.7(e)(3)	Yes.	
§ 63.7(e)(4)	Yes.	
§ 63.7(f)	Yes.	
§ 63.7(g)	Yes.	
§ 63.7(h)	Yes.	
§ 63.8(a)(1)	Yes.	
§ 63.8(a)(2)	Yes.	
§ 63.8(a)(3)	No	Section reserved.
§ 63.8(a)(4)	Yes.	
§ 63.8(b)(1)	Yes.	
§ 63.8(b)(2)	Yes.	
§ 63.8(b)(3)	Yes.	
§ 63.8(c)(1)	No.	
§ 63.8(c)(1)(i)	No.	
§ 63.8(c)(1)(ii)	Yes.	
§ 63.8(c)(1)(iii)	No.	
§ 63.8(c)(2)	Yes.	
§ 63.8(c)(3)	Yes.	
§ 63.8(c)(4)	Yes.	
§ 63.8(c)(4)(i)	No	Subpart HH does not require continuous opacity monitors.
§ 63.8(c)(4)(ii)	Yes.	
§ 63.8(c)(5) through (c)(8)	Yes.	
§ 63.8(d)(1)	Yes.	
§ 63.8(d)(2)	Yes.	
§ 63.8(d)(3)	Yes	Except for last sentence, which refers to an SSM plan. SSM plans are not required.
§ 63.8(e)	Yes	Subpart HH does not specifically require continuous emissions monitor performance evaluation, however, the Administrator can request that one be conducted.
§ 63.8(f)(1) through (f)(5)	Yes.	
§ 63.8(f)(6)	Yes.	
§ 63.8(g)	No	Subpart HH specifies continuous monitoring system data reduction requirements.
§ 63.9(a)	Yes.	
§ 63.9(b)(1)	Yes.	
§ 63.9(b)(2)	Yes	Existing sources are given 1 year (rather than 120 days) to submit this notification. Major and area sources that meet § 63.764(e) do not have to submit initial notifications.
§ 63.9(b)(3)	No	Section reserved.
§ 63.9(b)(4)	Yes.	
§ 63.9(b)(5)	Yes.	
§ 63.9(c)	Yes.	
§ 63.9(d)	Yes.	
§ 63.9(e)	Yes.	
§ 63.9(f)	Yes.	
§ 63.9(g)	Yes.	
§ 63.9(h)(1) through (h)(3)	Yes	Area sources located outside UA plus offset and UC boundaries are not required to submit notifications of compliance status.
§ 63.9(h)(4)	No	Section reserved.
§ 63.9(h)(5) through (h)(6)	Yes.	
§ 63.9(i)	Yes.	
§ 63.9(j)	Yes.	
§ 63.10(a)	Yes.	
§ 63.10(b)(1)	Yes	§ 63.774(b)(1) requires sources to maintain the most recent 12 months of data on-site and allows offsite storage for the remaining 4 years of data.
§ 63.10(b)(2)	Yes.	
§ 63.10(b)(2)(i)	No.	
§ 63.10(b)(2)(ii)	No	See § 63.774(g) for recordkeeping of (1) occurrence and duration and (2) actions taken during malfunctions.
§ 63.10(b)(2)(iii)	Yes.	
§ 63.10(b)(2)(iv) through (b)(2)(v)	No.	
§ 63.10(b)(2)(vi) through (b)(2)(xiv)	Yes.	

TABLE 2 TO SUBPART HH OF PART 63—APPLICABILITY OF 40 CFR PART 63 GENERAL PROVISIONS TO SUBPART HH—Continued

General provisions reference	Applicable to subpart HH	Explanation
§ 63.10(b)(3)	Yes	§ 63.774(b)(1) requires sources to maintain the most recent 12 months of data on-site and allows offsite storage for the remaining 4 years of data.
§ 63.10(c)(1)	Yes.	
§ 63.10(c)(2) through (c)(4)	No	Sections reserved.
§ 63.10(c)(5) through (c)(8)	Yes.	
§ 63.10(c)(9)	No	Section reserved.
§ 63.10(c)(10) through (11)	No	See § 63.774(g) for recordkeeping of malfunctions.
§ 63.10(c)(12) through (14)	Yes.	
§ 63.10(c)(15)	No.	
§ 63.10(d)(1)	Yes.	
§ 63.10(d)(2)	Yes	Area sources located outside UA plus offset and UC boundaries do not have to submit performance test reports.
§ 63.10(d)(3)	Yes.	
§ 63.10(d)(4)	Yes.	
§ 63.10(d)(5)	No	See § 63.775(b)(6) or (c)(6) for reporting of malfunctions.
§ 63.10(e)(1)	Yes	Area sources located outside UA plus offset and UC boundaries are not required to submit reports.
§ 63.10(e)(2)	Yes	Area sources located outside UA plus offset and UC boundaries are not required to submit reports.
§ 63.10(e)(3)(i)	Yes	Subpart HH requires major sources to submit Periodic Reports semi-annually. Area sources are required to submit Periodic Reports annually. Area sources located outside UA plus offset and UC boundaries are not required to submit reports.
§ 63.10(e)(3)(i)(A)	Yes.	
§ 63.10(e)(3)(i)(B)	Yes.	
§ 63.10(e)(3)(i)(C)	No.	
§ 63.10(e)(3)(i)(D)	Yes	Section reserved.
§ 63.10(e)(3)(ii) through (viii)	Yes.	
§ 63.10(e)(4)	Yes.	
§ 63.10(f)	Yes.	
§ 63.11(a) and (b)	Yes.	
§ 63.11(c), (d), and (e)	Yes.	
§ 63.12(a) through (c)	Yes.	
§ 63.13(a) through (c)	Yes.	
§ 63.14(a) through (q)	Yes.	
§ 63.15(a) and (b)	Yes.	
§ 63.16	Yes.	

Subpart HHH—[Amended]

■ 23. Section 63.1270 is amended by:
■ a. Revising paragraph (a) introductory text;
■ b. Revising paragraph (a)(4);
■ c. Revising paragraph (b);
■ d. Revising paragraphs (d)(1) and (2); and
■ e. Adding paragraphs (d)(3) and (4).

The revisions and additions read as follows:

§ 63.1270 Applicability and designation of affected source.

(a) This subpart applies to owners and operators of natural gas transmission and storage facilities that transport or store natural gas prior to entering the pipeline to a local distribution company or to a final end user (if there is no local distribution company), and that are major sources of hazardous air pollutants (HAP) emissions as defined in § 63.1271. Emissions for major source determination purposes can be estimated using the maximum natural gas throughput calculated in either paragraph (a)(1) or (2) of this section and paragraphs (a)(3) and (4) of this section. As an alternative to calculating the maximum natural gas throughput, the owner or operator of a new or existing source may use the facility design maximum natural gas throughput to estimate the maximum potential emissions. Other means to determine the facility's major source status are allowed, provided the information is documented and recorded to the Administrator's satisfaction in accordance with § 63.10(b)(3). A compressor station that transports natural gas prior to the point of custody transfer or to a natural gas processing plant (if present) is not considered a part of the natural gas transmission and storage source category. A facility that is determined to be an area source, but subsequently increases its emissions or its potential to emit above the major source levels (without obtaining and complying with other limitations that keep its potential to emit HAP below major source levels), and becomes a major source, must comply thereafter with all applicable provisions of this subpart starting on the applicable compliance date specified in paragraph (d) of this section. Nothing in this paragraph is intended to preclude a source from limiting its potential to emit through other appropriate mechanisms that may be available through the permitting authority.

* * * * *

(4) The owner or operator shall determine the maximum values for other parameters used to calculate potential emissions as the maximum over the same period for which maximum throughput is determined as specified in paragraph (a)(1) or (a)(2) of this section. These parameters shall be based on an annual average or the highest single measured value. For estimating maximum potential emissions from glycol dehydration units, the glycol circulation rate used in the calculation shall be the unit's maximum rate under its physical and

operational design consistent with the definition of potential to emit in § 63.2.

(b) The affected source is each new and existing glycol dehydration unit specified in paragraphs (b)(1) through (3) of this section.

(1) Each large glycol dehydration unit;

(2) Each small glycol dehydration unit for which construction commenced on or before August 23, 2011, is an existing small glycol dehydration unit.

(3) Each small glycol dehydration unit for which construction commenced after August 23, 2011, is a new small glycol dehydration unit.

* * * * *

(d) * * *

(1) Except as specified in paragraphs (d)(3) through (4) of this section, the owner or operator of an affected source, the construction or reconstruction of which commenced before February 6, 1998, shall achieve compliance with this provisions of the subpart no later than June 17, 2002 except as provided for in § 63.6(i). The owner or operator of an area source, the construction or reconstruction of which commenced before February 6, 1998, that increases its emissions of (or its potential to emit) HAP such that the source becomes a major source that is subject to this subpart shall comply with this subpart 3 years after becoming a major source.

(2) Except as specified in paragraphs (d)(3) through (4) of this section, the owner or operator of an affected source, the construction or reconstruction of which commences on or after February 6, 1998, shall achieve compliance with the provisions of this subpart immediately upon initial startup or June 17, 1999, whichever date is later. Area sources, the construction or reconstruction of which commences on or after February 6, 1998, that become major sources shall comply with the provisions of this standard immediately upon becoming a major source.

(3) Each affected small glycol dehydration unit, as defined in § 63.1271, located at a major source, that commenced construction before August 23, 2011, must achieve compliance no later than October 15, 2015, except as provided in § 63.6(i).

(4) Each affected small glycol dehydration unit, as defined in § 63.1271, located at a major source, that commenced construction on or after August 23, 2011, must achieve compliance immediately upon initial startup or October 15, 2012, whichever is later.

* * * * *

■ 24. Section 63.1271 is amended by:

■ a. Adding, in alphabetical order, definitions for the terms ''affirmative defense,'' ''BTEX,'' ''flare,'' ''large glycol dehydration units,'' ''responsible official'' and ''small glycol dehydration units;'' and

■ b. Revising the definition for ''glycol dehydration unit baseline operations.''

The additions and revision read as follows:

§ 63.1271 Definitions.

* * * * *

Affirmative defense means, in the context of an enforcement proceeding, a response or defense put forward by a defendant, regarding which the defendant has the burden of proof, and the merits of which are independently and objectively evaluated in a judicial or administrative proceeding.

* * * * *

BTEX means benzene, toluene, ethyl benzene, and xylene.

* * * * *

Flare means a thermal oxidation system using an open flame (*i.e.,* without enclosure).

* * * * *

Glycol dehydration unit baseline operations means operations representative of the large glycol dehydration unit operations as of June 17, 1999 and the small glycol dehydration unit operations as of August 23, 2011. For the purposes of this subpart, for determining the percentage of overall HAP emission reduction attributable to process modifications, glycol dehydration unit baseline operations shall be parameter values (including, but not limited to, glycol circulation rate or glycol-HAP absorbency) that represent actual long-term conditions (*i.e.,* at least 1 year). Glycol dehydration units in operation for less than 1 year shall document that the parameter values represent expected long-term operating conditions had process modifications not been made.

* * * * *

Large glycol dehydration unit means a glycol dehydration unit with an actual annual average natural gas flowrate equal to or greater than 283.0 thousand standard cubic meters per day and actual annual average benzene emissions equal to or greater than 0.90 Mg/yr, determined according to § 63.1282(a). A glycol dehydration unit complying with the 0.9 Mg/yr control option under 63.1275(b)(1)(ii) is considered to be a large dehydrator.

* * * * *

Responsible official means one of the following:

(1) For a corporation: A president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit and either:

(i) The facilities employ more than 250 persons or have gross annual sales or expenditures exceeding $25 million (in second quarter 1980 dollars); or

(ii) The delegation of authority to such representatives is approved in advance by the permitting authority;

(2) For a partnership or sole proprietorship: A general partner or the proprietor, respectively;

(3) For a municipality, State, Federal, or other public agency: Either a principal executive officer or ranking elected official. For the purposes of this part, a principal executive officer of a Federal agency includes the chief executive officer having responsibility for the overall operations of a principal geographic unit of the agency (*e.g.,* a Regional Administrator of EPA); or

(4) For affected sources:

(i) The designated representative in so far as actions, standards, requirements, or prohibitions under title IV of the Act or the regulations promulgated thereunder are concerned; and

(ii) The designated representative for any other purposes under part 70.

* * * * *

Small glycol dehydration unit means a glycol dehydration unit, located at a major source, with an actual annual average natural gas flowrate less than 283.0 thousand standard cubic meters per day or actual annual average benzene emissions less than 0.90 Mg/yr, determined according to § 63.1282(a).

* * * * *

■ 25. Section 63.1272 is revised to read as follows:

§ 63.1272 Affirmative defense for violations of emission standards during malfunction.

(a) The provisions set forth in this subpart shall apply at all times.

(b) [Reserved]

(c) [Reserved]

(d) In response to an action to enforce the standards set forth in this subpart, you may assert an affirmative defense to a claim for civil penalties for violations of such standards that are caused by malfunction, as defined at § 63.2. Appropriate penalties may be assessed; however, if you fail to meet your burden of proving all of the requirements in the affirmative defense, the affirmative defense shall not be available for claims for injunctive relief.

(1) To establish the affirmative defense in any action to enforce such a standard, you must timely meet the reporting requirements in paragraph (d)(2) of this section, and must prove by a preponderance of evidence that:

(i) The violation:

(A) Was caused by a sudden, infrequent, and unavoidable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner; and

(B) Could not have been prevented through careful planning, proper design or better operation and maintenance practices; and

(C) Did not stem from any activity or event that could have been foreseen and avoided, or planned for; and

(D) Was not part of a recurring pattern indicative of inadequate design, operation, or maintenance; and

(ii) Repairs were made as expeditiously as possible when a violation occurred. Off-shift and overtime labor were used, to the extent practicable to make these repairs; and

(iii) The frequency, amount and duration of the violation (including any bypass) were minimized to the maximum extent practicable; and

(iv) If the violation resulted from a bypass of control equipment or a process, then the bypass was unavoidable to prevent loss of life, personal injury, or severe property damage; and

(v) All possible steps were taken to minimize the impact of the violation on ambient air quality, the environment, and human health; and

(vi) All emissions monitoring and control systems were kept in operation if at all possible, consistent with safety and good air pollution control practices; and

(vii) All of the actions in response to the violation were documented by properly signed, contemporaneous operating logs; and

(viii) At all times, the affected source was operated in a manner consistent with good practices for minimizing emissions; and

(ix) A written root cause analysis has been prepared, the purpose of which is to determine, correct, and eliminate the primary causes of the malfunction and the violation resulting from the malfunction event at issue. The analysis shall also specify, using best monitoring methods and engineering judgment, the amount of any emissions that were the result of the malfunction.

(2) *Report.* The owner or operator seeking to assert an affirmative defense shall submit a written report to the Administrator with all necessary supporting documentation, that it has met the requirements set forth in paragraph (d)(1) of this section. This affirmative defense report shall be included in the first periodic compliance, deviation report or excess emission report otherwise required after the initial occurrence of the violation of the relevant standard (which may be the end of any applicable averaging period). If such compliance, deviation report or excess emission report is due less than 45 days after the initial occurrence of the violation, the affirmative defense report may be included in the second compliance, deviation report or excess emission report due after the initial occurrence of the violation of the relevant standard.

■ 26. Section 63.1274 is amended by:

■ a. Revising paragraph (c) introductory text;

■ b. Removing and reserving paragraph (d);

■ c. Revising paragraph (g); and

■ d. Adding paragraph (h).

The revisions and addition read as follows:

§ 63.1274 General standards.

* * * * *

(c) The owner or operator of an affected source (*i.e.,* glycol dehydration unit) located at an existing or new major source of HAP emissions shall comply with the requirements in this subpart as follows:

* * * * *

(d) [Reserved]

* * * * *

(g) In all cases where the provisions of this subpart require an owner or operator to repair leaks by a specified time after the leak is detected, it is a violation of this standard to fail to take action to repair the leak(s) within the specified time. If action is taken to repair the leak(s) within the specified time, failure of that action to successfully repair the leak(s) is not a violation of this standard. However, if the repairs are unsuccessful, and a leak is detected, the owner or operator shall take further action as required by the applicable provisions of this subpart.

(h) At all times the owner or operator must operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.

■ 27. Section 63.1275 is amended by:

■ a. Revising paragraph (a);

■ b. Revising paragraph (b)(1);

■ c. Revising paragraph (c)(2); and

■ d. Revising paragraph (c)(3).

The revisions read as follows:

§ 63.1275 Glycol dehydration unit process vent standards.

(a) This section applies to each glycol dehydration unit subject to this subpart that must be controlled for air emissions as specified in paragraph (c)(1) of § 63.1274.

(b) * * *

(1) For each glycol dehydration unit process vent, the owner or operator shall control air emissions by either paragraph (b)(1)(i) or (iii) of this section.

(i) The owner or operator of a large glycol dehydration unit, as defined in § 63.1271, shall connect the process vent to a control device or a combination of control devices through a closed-vent system. The closed-vent system shall be designed and operated in accordance with the requirements of § 63.1281(c). The control device(s) shall be designed and operated in accordance with the requirements of § 63.1281(d).

(ii) The owner or operator of a large glycol dehydration unit shall connect the process vent to a control device or a combination of control devices through a closed-vent system and the outlet benzene emissions from the control device(s) shall be less than 0.90 megagrams per year. The closed-vent system shall be designed and operated in accordance with the requirements of § 63.1281(c). The control device(s) shall be designed and operated in accordance with the requirements of § 63.1281(d), except that the performance requirements specified in § 63.1281(d)(1)(i) and (ii) do not apply.

(iii) You must limit BTEX emissions from each existing small glycol dehydration unit, as defined in § 63.1271, to the limit determined in Equation 1 of this section. You must limit BTEX emissions from each new small glycol dehydration unit process vent, as defined in § 63.1271, to the limit determined in Equation 2 of this section. The limits determined using Equation 1 or Equation 2, of this section, must be met in accordance with one of the alternatives specified in paragraphs (b)(1)(iii)(A) through (D) of this section.

$$EL_{BTEX} = 3.10x10^{-4} * Throughput * C_{i,BTEX} * 365 \frac{days}{yr} * \frac{1\ Mg}{1x10^{6}\ grams} \quad \text{Equation 1}$$

Where:

EL_{BTEX} = Unit-specific BTEX emission limit, megagrams per year;

3.10×10^{-4} = BTEX emission limit, grams BTEX/standard cubic meter-ppmv;

Throughput = Annual average daily natural gas throughput, standard cubic meters per day;

$C_{i,BTEX}$ = Annual average BTEX concentration of the natural gas at the inlet to the glycol dehydration unit, ppmv.

$$EL_{BTEX} = 5.44x10^{-5} * Throughput * C_{i,BTEX} * 365 \frac{days}{yr} * \frac{1\ Mg}{1x10^{6}\ grams} \quad \text{Equation 2}$$

Where:

EL_{BTEX} = Unit-specific BTEX emission limit, megagrams per year;

5.44×10^{-5} = BTEX emission limit, grams BTEX/standard cubic meter-ppmv;

Throughput = Annual average daily natural gas throughput, standard cubic meters per day;

$C_{i,BTEX}$ = Annual average BTEX concentration of the natural gas at the inlet to the glycol dehydration unit, ppmv.

(A) Connect the process vent to a control device or combination of control devices through a closed-vent system. The closed vent system shall be designed and operated in accordance with the requirements of § 63.1281(c). The control device(s) shall be designed and operated in accordance with the requirements of § 63.1281(f).

(B) Meet the emissions limit through process modifications in accordance with the requirements specified in § 63.1281(e).

(C) Meet the emission limit for each small glycol dehydration unit using a combination of process modifications and one or more control devices through the requirements specified in paragraphs (b)(1)(iii)(A) and (B) of this section.

(D) Demonstrate that the emissions limit is met through actual uncontrolled operation of the small glycol dehydration unit. Document operational parameters in accordance with the requirements specified in § 63.1281(e) and emissions in accordance with the requirements specified in § 63.1282(a)(3).

* * * * *

(c) * * *

(2) The owner or operator shall demonstrate, to the Administrator's satisfaction, that the total HAP emissions to the atmosphere from the large glycol dehydration unit process vent are reduced by 95.0 percent through process modifications or a combination of process modifications and one or more control devices, in accordance with the requirements specified in § 63.1281(e).

(3) Control of HAP emissions from a GCG separator (flash tank) vent is not required if the owner or operator demonstrates, to the Administrator's satisfaction, that total emissions to the atmosphere from the glycol dehydration unit process vent are reduced by one of the levels specified in paragraph (c)(3)(i) through (iv) through the installation and operation of controls as specified in paragraph (b)(1) of this section.

(i) For any large glycol dehydration unit, HAP emissions are reduced by 95.0 percent or more.

(ii) For any large glycol dehydration unit, benzene emissions are reduced to a level less than 0.90 megagrams per year.

(iii) For each existing small glycol dehydration unit, BTEX emissions are reduced to a level less than the limit calculated in Equation 1 of paragraph (b)(1)(iii) of this section.

(iv) For each new small glycol dehydration unit, BTEX emissions are reduced to a level less than the limit calculated in Equation 2 of paragraph (b)(1)(iii) of this section.

■ 28. Section 63.1281 is amended by:

■ a. Revising paragraph (c)(1);

■ b. Revising the heading of paragraph (d).

■ c. Adding paragraph (d) introductory text;

■ d. Revising paragraph (d)(1)(i)(C);

■ e. Revising paragraphs (d)(1)(ii) and (iii);

■ f. Revising paragraph (d)(4)(i);

■ g. Revising paragraph (d)(5)(i);

■ h. Revising paragraph (e)(2);

■ i. Revising paragraph (e)(3) introductory text;

■ j. Revising paragraph (e)(3)(ii); and

■ k. Adding paragraph (f).

The revisions and additions read as follows:

§ 63.1281 Control equipment requirements.

* * * * *

(c) * * *

(1) The closed-vent system shall route all gases, vapors, and fumes emitted from the material in an emissions unit to a control device that meets the requirements specified in paragraph (d) of this section.

* * * * *

(d) *Control device requirements for sources except small glycol dehydration units.* Owners and operators of small glycol dehydration units shall comply with the control requirements in paragraph (f) of this section.

(1) * * *

(i) * * *

(C) Operates at a minimum temperature of 760 degrees C, provided the control device has demonstrated, under § 63.1282(d), that combustion zone temperature is an indicator of destruction efficiency.

* * * * *

(ii) A vapor recovery device (*e.g.,* carbon adsorption system or condenser) or other non-destructive control device that is designed and operated to reduce the mass content of either TOC or total HAP in the gases vented to the device by 95.0 percent by weight or greater as determined in accordance with the requirements of § 63.1282(d).

(iii) A flare, as defined in § 63.1271, that is designed and operated in accordance with the requirements of § 63.11(b).

* * * * *

(4) * * *

(i) Each control device used to comply with this subpart shall be operating at all times when gases, vapors, and fumes are vented from the emissions unit or units through the closed vent system to the control device as required under § 63.1275. An owner or operator may vent more than one unit to a control device used to comply with this subpart.

* * * * *

(5) * * *

(i) Following the initial startup of the control device, all carbon in the control device shall be replaced with fresh carbon on a regular, predetermined time interval that is no longer than the carbon service life established for the

carbon adsorption system. Records identifying the schedule for replacement and records of each carbon replacement shall be maintained as required in § 63.1284(b)(7)(ix). The schedule for replacement shall be submitted with the Notification of Compliance Status Report as specified in § 63.1285(d)(4)(iv). Each carbon replacement must be reported in the Periodic Reports as specified in § 63.1285(e)(2)(xi).

* * * * *

(e) * * *

(2) The owner or operator shall document, to the Administrator's satisfaction, the conditions for which glycol dehydration unit baseline operations shall be modified to achieve the 95.0 percent overall HAP emission reduction, or BTEX limit determined in § 63.1275(b)(1)(iii), as applicable, either through process modifications or through a combination of process modifications and one or more control devices. If a combination of process modifications and one or more control devices are used, the owner or operator shall also establish the emission reduction to be achieved by the control device to achieve an overall HAP emission reduction of 95.0 percent for the glycol dehydration unit process vent or, if applicable, the BTEX limit determined in § 63.1275(b)(1)(iii) for the small glycol dehydration unit process vent. Only modifications in glycol dehydration unit operations directly related to process changes, including but not limited to changes in glycol circulation rate or glycol-HAP absorbency, shall be allowed. Changes in the inlet gas characteristics or natural gas throughput rate shall not be considered in determining the overall emission reduction due to process modifications.

(3) The owner or operator that achieves a 95.0 percent HAP emission reduction or meets the BTEX limit determined in § 63.1275(b)(1)(iii), as applicable, using process modifications alone shall comply with paragraph (e)(3)(i) of this section. The owner or operator that achieves a 95.0 percent HAP emission reduction or meets the BTEX limit determined in § 63.1275(b)(1)(iii), as applicable, using a combination of process modifications and one or more control devices shall comply with paragraphs (e)(3)(i) and (e)(3)(ii) of this section.

* * * * *

(ii) The owner or operator shall comply with the control device requirements specified in paragraph (d) or (f) of this section, as applicable, except that the emission reduction or limit achieved shall be the emission reduction or limit specified for the control device(s) in paragraph (e)(2) of this section.

(f) *Control device requirements for small glycol dehydration units.* (1) The control device used to meet BTEX the emission limit calculated in § 63.1275(b)(1)(iii) shall be one of the control devices specified in paragraphs (f)(1)(i) through (iii) of this section.

(i) An enclosed combustion device (*e.g.,* thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater) that is designed and operated to meet the levels specified in paragraphs (f)(1)(i)(A) or (B) of this section. If a boiler or process heater is used as the control device, then the vent stream shall be introduced into the flame zone of the boiler or process heater.

(A) The mass content of BTEX in the gases vented to the device is reduced as determined in accordance with the requirements of § 63.1282(d).

(B) The concentration of either TOC or total HAP in the exhaust gases at the outlet of the device is reduced to a level equal to or less than 20 parts per million by volume on a dry basis corrected to 3 percent oxygen as determined in accordance with the requirements of § 63.1282(e).

(ii) A vapor recovery device (*e.g.,* carbon adsorption system or condenser) or other non-destructive control device that is designed and operated to reduce the mass content of BTEX in the gases vented to the device as determined in accordance with the requirements of § 63.1282(d).

(iii) A flare, as defined in § 63.1271, that is designed and operated in accordance with the requirements of § 63.11(b).

(2) The owner or operator shall operate each control device in accordance with the requirements specified in paragraphs (f)(2)(i) and (ii) of this section.

(i) Each control device used to comply with this subpart shall be operating at all times. An owner or operator may vent more than one unit to a control device used to comply with this subpart.

(ii) For each control device monitored in accordance with the requirements of § 63.1283(d), the owner or operator shall demonstrate compliance according to the requirements of either § 63.1282(e) or (h).

(3) For each carbon adsorption system used as a control device to meet the requirements of paragraph (f)(1) of this section, the owner or operator shall manage the carbon as required under (d)(5)(i) and (ii) of this section.

■ 29. Section 63.1282 is amended by:

■ a. Revising paragraph (a) introductory text;
■ b. Revising paragraph (a)(1)(ii);
■ c. Revising paragraph (a)(2);
■ d. Revising paragraph (b)(6)(i);
■ e. Adding paragraph (c);
■ f. Revising paragraph (d) introductory text;
■ g. Revising paragraphs (d)(1)(i) through (v);
■ h. Revising paragraph (d)(2);
■ i. Revising paragraph (d)(3) introductory text;
■ j. Revising paragraph (d)(3)(i)(B);
■ k. Revising paragraph (d)(3)(iii) introductory text;
■ l. Revising paragraph (d)(3)(iv) introductory text;
■ m. Revising paragraph (d)(3)(iv)(C)(*1*);
■ n. Adding paragraphs (d)(3)(v) and (vi);
■ o. Revising paragraph (d)(4) introductory text;
■ p. Revising paragraph (d)(4)(i);
■ q. Revising paragraph (d)(5);
■ r. Revising paragraph (e) introductory text;
■ s. Revising paragraphs (e)(2) and (3);
■ t. Adding paragraphs (e)(4) through (e)(6);
■ u. Revising paragraph (f) introductory text;
■ v. Revising paragraph (f)(1);
■ w. Revising paragraph (f)(2) introductory text;
■ x. Revising paragraph (f)(2)(iii) introductory text, (f)(2)(iii)(A) and (f)(2)(iii)(B);
■ y. Revising paragraph (f)(3); and
■ z. Adding paragraphs (g) and (h).

The revisions and additions read as follows:

§ 63.1282 Test methods, compliance procedures, and compliance demonstrations.

(a) *Determination of glycol dehydration unit flowrate, benzene emissions, or BTEX emissions.* The procedures of this paragraph shall be used by an owner or operator to determine glycol dehydration unit natural gas flowrate, benzene emissions, or BTEX emissions.

(1) * * *

(ii) The owner or operator shall document, to the Administrator's satisfaction, the actual annual average natural gas flowrate to the glycol dehydration unit.

(2) The determination of actual average benzene or BTEX emissions from a glycol dehydration unit shall be made using the procedures of either paragraph (a)(2)(i) or (ii) of this section. Emissions shall be determined either uncontrolled or with federally enforceable controls in place.

(i) The owner or operator shall determine actual average benzene or

BTEX emissions using the model GRI–GLYCalc™, Version 3.0 or higher, and the procedures presented in the associated GRI–GLYCalc™ Technical Reference Manual. Inputs to the model shall be representative of actual operating conditions of the glycol dehydration unit and may be determined using the procedures documented in the Gas Research Institute (GRI) report entitled ''Atmospheric Rich/Lean Method for Determining Glycol Dehydrator Emissions'' (GRI–95/0368.1); or

(ii) The owner or operator shall determine an average mass rate of benzene or BTEX emissions in kilograms per hour through direct measurement by performing three runs of Method 18 in 40 CFR part 60, appendix A; or ASTM D6420–99 (Reapproved 2004) (incorporated by reference as specified in § 63.14), as specified in § 63.772(a)(1)(ii); or an equivalent method; and averaging the results of the three runs. Annual emissions in kilograms per year shall be determined by multiplying the mass rate by the number of hours the unit is operated per year. This result shall be converted to megagrams per year.

(b) * * *

(6) * * *

(i) Except as provided in paragraph (b)(6)(ii) of this section, the detection instrument shall meet the performance criteria of Method 21 of 40 CFR part 60, appendix A, except the instrument response factor criteria in section 3.1.2(a) of Method 21 shall be for the average composition of the process fluid not each individual volatile organic compound in the stream. For process streams that contain nitrogen, air, or other inert gases that are not organic HAP or VOC, the average stream response factor shall be calculated on an inert-free basis.

* * * * *

(c) *Test procedures and compliance demonstrations for small glycol dehydration units.* This paragraph (c) applies to the test procedures for small dehydration units.

(1) If the owner or operator is using a control device to comply with the emission limit in § 63.1275(b)(1)(iii), the requirements of paragraph (d) of this section apply. Compliance is demonstrated using the methods specified in paragraph (e) of this section.

(2) If no control device is used to comply with the emission limit in § 63.1275(b)(1)(iii), the owner or operator must determine the glycol dehydration unit BTEX emissions as specified in paragraphs (c)(2)(i) through (iii) of this section. Compliance is demonstrated if the BTEX emissions determined as specified in paragraphs (c)(2)(i) through (iii) are less than the emission limit calculated using the equation in § 63.1275(b)(1)(iii).

(i) Method 1 or 1A, 40 CFR part 60, appendix A, as appropriate, shall be used for selection of the sampling sites at the outlet of the glycol dehydration unit process vent. Any references to particulate mentioned in Methods 1 and 1A do not apply to this section.

(ii) The gas volumetric flowrate shall be determined using Method 2, 2A, 2C, or 2D, 40 CFR part 60, appendix A, as appropriate.

(iii) The BTEX emissions from the outlet of the glycol dehydration unit process vent shall be determined using the procedures specified in paragraph (d)(3)(v) of this section. As an alternative, the mass rate of BTEX at the outlet of the glycol dehydration unit process vent may be calculated using the model GRI–GLYCalc™, Version 3.0 or higher, and the procedures presented in the associated GRI–GLYCalc™ Technical Reference Manual. Inputs to the model shall be representative of actual operating conditions of the glycol dehydration unit and shall be determined using the procedures documented in the Gas Research Institute (GRI) report entitled ''Atmospheric Rich/Lean Method for Determining Glycol Dehydrator Emissions'' (GRI–95/0368.1). When the BTEX mass rate is calculated for glycol dehydration units using the model GRI–GLYCalc™, all BTEX measured by Method 18, 40 CFR part 60, appendix A, shall be summed.

(d) *Control device performance test procedures.* This paragraph applies to the performance testing of control devices. The owners or operators shall demonstrate that a control device achieves the performance requirements of § 63.1281(d)(1), (e)(3)(ii), or (f)(1) using a performance test as specified in paragraph (d)(3) of this section. Owners or operators using a condenser have the option to use a design analysis as specified in paragraph (d)(4) of this section. The owner or operator may elect to use the alternative procedures in paragraph (d)(5) of this section for performance testing of a condenser used to control emissions from a glycol dehydration unit process vent. Flares shall meet the provisions in paragraph (d)(2) of this section. As an alternative to conducting a performance test under this section for combustion control devices, a control device that can be demonstrated to meet the performance requirements of § 63.1281(d)(1), (e)(3)(ii), or (f)(1) through a performance test conducted by the manufacturer, as specified in paragraph (g) of this section, can be used.

(1) * * *

(i) Except as specified in paragraph (d)(2) of this section, a flare, as defined in § 63.1271, that is designed and operated in accordance with § 63.11(b);

(ii) Except for control devices used for small glycol dehydration units, a boiler or process heater with a design heat input capacity of 44 megawatts or greater;

(iii) Except for control devices used for small glycol dehydration units, a boiler or process heater into which the vent stream is introduced with the primary fuel or is used as the primary fuel;

(iv) Except for control devices used for small glycol dehydration units, a boiler or process heater burning hazardous waste for which the owner or operator has either been issued a final permit under 40 CFR part 270 and complies with the requirements of 40 CFR part 266, subpart H, or has certified compliance with the interim status requirements of 40 CFR part 266, subpart H;

(v) Except for control devices used for small glycol dehydration units, a hazardous waste incinerator for which the owner or operator has been issued a final permit under 40 CFR part 270 and complies with the requirements of 40 CFR part 264, subpart O, or has certified compliance with the interim status requirements of 40 CFR part 265, subpart O.

* * * * *

(2) An owner or operator shall design and operate each flare, as defined in § 63.1271, in accordance with the requirements specified in § 63.11(b) and the compliance determination shall be conducted using Method 22 of 40 CFR part 60, appendix A, to determine visible emissions.

(3) For a performance test conducted to demonstrate that a control device meets the requirements of § 63.1281(d)(1), (e)(3)(ii), or (f)(1) the owner or operator shall use the test methods and procedures specified in paragraphs (d)(3)(i) through (v) of this section. The initial and periodic performance tests shall be conducted according to the schedule specified in paragraph (d)(3)(vi) of this section.

(i) * * *

(B) To determine compliance with the enclosed combustion device total HAP concentration limit specified in § 63.1281(d)(1)(i)(B), or the BTEX emission limit specified in § 63.1275(b)(1)(iii), the sampling site

shall be located at the outlet of the combustion device.

* * * * *

(iii) To determine compliance with the control device percent reduction performance requirement in § 63.1281(d)(1)(i)(A), 63.1281(d)(1)(ii), or 63.1281(e)(3)(ii), the owner or operator shall use either Method 18, 40 CFR part 60, appendix A, or Method 25A, 40 CFR part 60, appendix A; or ASTM D6420–99 (incorporated by reference as specified in § 63.14), as specified in § 63.772(a)(1)(ii); alternatively, any other method or data that have been validated according to the applicable procedures in Method 301 of appendix A of this part may be used. The following procedures shall be used to calculate the percentage of reduction:

* * * * *

(iv) To determine compliance with the enclosed combustion device total HAP concentration limit specified in § 63.1281(d)(1)(i)(B), the owner or operator shall use either Method 18, 40 CFR part 60, appendix A; or Method 25A, 40 CFR part 60, appendix A; or ASTM D6420–99 (Reapproved 2004) (incorporated by reference as specified in § 63.14), as specified in § 63.772(a)(1)(ii), to measure either TOC (minus methane and ethane) or total HAP. Alternatively, any other method or data that have been validated according to Method 301 of appendix A of this part, may be used. The following procedures shall be used to calculate parts per million by volume concentration, corrected to 3 percent oxygen:

* * * * *

(C) * * *

(*1*) The emission rate correction factor for excess air, integrated sampling and analysis procedures of Method 3A or 3B, 40 CFR part 60, appendix A, ASTM D6522–00 (Reapproved 2005), or ANSI/ASME PTC 19.10–1981, Part 10 (manual portion only) (incorporated by reference as specified in § 63.14) shall be used to determine the oxygen concentration ($\%O_{2d}$). The samples shall be taken during the same time that the samples are taken for determining TOC concentration or total HAP concentration.

* * * * *

(v) To determine compliance with the BTEX emission limit specified in § 63.1275(b)(1)(iii) the owner or operator shall use one of the following methods: Method 18, 40 CFR part 60, appendix A; ASTM D6420–99 (Reapproved 2004) (incorporated by reference as specified in § 63.14), as specified in § 63.772(a)(1)(ii); or any other method or data that have been validated according to the applicable procedures in Method 301, 40 CFR part 63, appendix A. The following procedures shall be used to calculate BTEX emissions:

(A) The minimum sampling time for each run shall be 1 hour in which either an integrated sample or a minimum of four grab samples shall be taken. If grab sampling is used, then the samples shall be taken at approximately equal intervals in time, such as 15-minute intervals during the run.

(B) The mass rate of BTEX (E_o) shall be computed using the equations and procedures specified in paragraphs (d)(3)(v)(B)(*1*) and (*2*) of this section.

(*1*) The following equation shall be used:

$$E_o = K_2\left(\sum_{j=1}^{n} C_{oj}M_{oj}\right)Q_o$$

Where:

E_o = Mass rate of BTEX at the outlet of the control device, dry basis, kilogram per hour.

C_{oj} = Concentration of sample component j of the gas stream at the outlet of the control device, dry basis, parts per million by volume.

M_{oj} = Molecular weight of sample component j of the gas stream at the outlet of the control device, gram/gram-mole.

Q_o = Flowrate of gas stream at the outlet of the control device, dry standard cubic meter per minute.

K_2 = Constant, 2.494×10^{-6} (parts per million) (gram-mole per standard cubic meter) (kilogram/gram) (minute/hour), where standard temperature (gram-mole per standard cubic meter) is 20 degrees C.

n = Number of components in sample.

(*2*) When the BTEX mass rate is calculated, only BTEX compounds measured by Method 18, 40 CFR part 60, appendix A, or ASTM D6420–99 (Reapproved 2004) (incorporated by reference as specified in § 63.14) as specified in § 63.772(a)(1)(ii), shall be summed using the equations in paragraph (d)(3)(v)(B)(*1*) of this section.

(vi) The owner or operator shall conduct performance tests according to the schedule specified in paragraphs (d)(3)(vi)(A) and (B) of this section.

(A) An initial performance test shall be conducted within 180 days after the compliance date that is specified for each affected source in § 63.1270(d)(3) and (4) except that the initial performance test for existing combustion control devices (*i.e.,* control devices installed on or before August 23, 2011) at major sources shall be conducted no later than October 15, 2015. If the owner or operator of an existing combustion control device at a major source chooses to replace such device with a control device whose model is tested under § 63.1282(g), then the newly installed device shall comply with all provisions of this subpart no later than October 15, 2015. The performance test results shall be submitted in the Notification of Compliance Status Report as required in § 63.1285(d)(1)(ii).

(B) Periodic performance tests shall be conducted for all control devices required to conduct initial performance tests except as specified in paragraphs (e)(3)(vi)(B)(*1*) and (*2*) of this section. The first periodic performance test shall be conducted no later than 60 months after the initial performance test required in paragraph (d)(3)(vi)(A) of this section. Subsequent periodic performance tests shall be conducted at intervals no longer than 60 months following the previous periodic performance test or whenever a source desires to establish a new operating limit. The periodic performance test results must be submitted in the next Periodic Report as specified in § 63.1285(e)(2)(x). Combustion control devices meeting the criteria in either paragraph (e)(3)(vi)(B)(*1*) or (*2*) of this section are not required to conduct periodic performance tests.

(*1*) A control device whose model is tested under, and meets the criteria of, § 63.1282(g), or

(*2*) A combustion control device demonstrating during the performance test under § 63.1282(d) that combustion zone temperature is an indicator of destruction efficiency and operates at a minimum temperature of 760 degrees C.

(4) For a condenser design analysis conducted to meet the requirements of § 63.1281(d)(1), (e)(3)(ii), or (f)(1), the owner or operator shall meet the requirements specified in paragraphs (d)(4)(i) and (ii) of this section. Documentation of the design analysis shall be submitted as a part of the Notification of Compliance Status Report as required in § 63.1285(d)(1)(i).

(i) The condenser design analysis shall include an analysis of the vent stream composition, constituent concentrations, flowrate, relative humidity, and temperature, and shall establish the design outlet organic compound concentration level, design average temperature of the condenser exhaust vent stream, and the design average temperatures of the coolant fluid at the condenser inlet and outlet. As an alternative to the condenser design analysis, an owner or operator may elect to use the procedures specified in paragraph (d)(5) of this section.

* * * * *

(5) As an alternative to the procedures in paragraph (d)(4)(i) of this section, an owner or operator may elect to use the procedures documented in the GRI report entitled, ''Atmospheric Rich/Lean Method for Determining Glycol Dehydrator Emissions,'' (GRI–95/0368.1) as inputs for the model GRI–GLYCalc™, Version 3.0 or higher, to generate a condenser performance curve.

(e) *Compliance demonstration for control devices performance requirements.* This paragraph applies to the demonstration of compliance with the control device performance requirements specified in § 63.1281(d)(1), (e)(3)(ii), and (f)(1). Compliance shall be demonstrated using the requirements in paragraphs (e)(1) through (3) of this section. As an alternative, an owner or operator that installs a condenser as the control device to achieve the requirements specified in § 63.1281(d)(1)(ii), (e)(3)(ii), or (f)(1) may demonstrate compliance according to paragraph (f) of this section. An owner or operator may switch between compliance with paragraph (e) of this section and compliance with paragraph (f) of this section only after at least 1 year of operation in compliance with the selected approach. Notification of such a change in the compliance method shall be reported in the next Periodic Report, as required in § 63.1285(e), following the change.

* * * * *

(2) The owner or operator shall calculate the daily average of the applicable monitored parameter in accordance with § 63.1283(d)(4) except that the inlet gas flowrate to the control device shall not be averaged.

(3) Compliance is achieved when the daily average of the monitoring parameter value calculated under paragraph (e)(2) of this section is either equal to or greater than the minimum or equal to or less than the maximum monitoring value established under paragraph (e)(1) of this section. For inlet gas flowrate, compliance with the operating parameter limit is achieved when the value is equal to or less than the value established under § 63.1282(g) or under the performance test conducted under § 63.1282(d), as applicable.

(4) Except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities (including, as applicable, system accuracy audits and required zero and span adjustments), the CMS required in § 63.1283(d) must be operated at all times the affected source is operating. A monitoring system malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring system to provide valid data. Monitoring system failures that are caused in part by poor maintenance or careless operation are not malfunctions. Monitoring system repairs are required to be completed in response to monitoring system malfunctions and to return the monitoring system to operation as expeditiously as practicable.

(5) Data recorded during monitoring system malfunctions, repairs associated with monitoring system malfunctions, or required monitoring system quality assurance or control activities may not be used in calculations used to report emissions or operating levels. All the data collected during all other required data collection periods must be used in assessing the operation of the control device and associated control system.

(6) Except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required quality monitoring system quality assurance or quality control activities (including, as applicable, system accuracy audits and required zero and span adjustments), failure to collect required data is a deviation of the monitoring requirements.

(f) *Compliance demonstration with percent reduction or emission limit performance requirements—condensers.* This paragraph applies to the demonstration of compliance with the performance requirements specified in § 63.1281(d)(1)(ii), (e)(3) or (f)(1) for condensers. Compliance shall be demonstrated using the procedures in paragraphs (f)(1) through (f)(3) of this section.

(1) The owner or operator shall establish a site-specific condenser performance curve according to the procedures specified in § 63.1283(d)(5)(ii). For sources required to meet the BTEX limit in accordance with § 63.1281(e) or (f)(1) the owner or operator shall identify the minimum percent reduction necessary to meet the BTEX limit.

(2) Compliance with the percent reduction requirement in § 63.1281(d)(1)(ii), (e)(3), or (f)(1) shall be demonstrated by the procedures in paragraphs (f)(2)(i) through (iii) of this section.

* * * * *

(iii) Except as provided in paragraphs (f)(2)(iii)(A), (B), and (D) of this section, at the end of each operating day the owner or operator shall calculate the 30-day average HAP, or BTEX, emission reduction, as appropriate, from the condenser efficiencies as determined in paragraph (f)(2)(ii) of this section for the preceding 30 operating days. If the owner or operator uses a combination of process modifications and a condenser in accordance with the requirements of § 63.1281(e), the 30-day average HAP emission, or BTEX, emission reduction, shall be calculated using the emission reduction achieved through process modifications and the condenser efficiency as determined in paragraph (f)(2)(ii) of this section, both for the preceding 30 operating days.

(A) After the compliance date specified in § 63.1270(d), an owner or operator of a facility that stores natural gas that has less than 30 days of data for determining the average HAP, or BTEX, emission reduction, as appropriate, shall calculate the cumulative average at the end of the withdrawal season, each season, until 30 days of condenser operating data are accumulated. For a facility that does not store natural gas, the owner or operator that has less than 30 days of data for determining average HAP, or BTEX, emission reduction, as appropriate, shall calculate the cumulative average at the end of the calendar year, each year, until 30 days of condenser operating data are accumulated.

(B) After the compliance date specified in § 63.1270(d), for an owner or operator that has less than 30 days of data for determining the average HAP, or BTEX, emission reduction, as appropriate, compliance is achieved if the average HAP, or BTEX, emission reduction, as appropriate, calculated in paragraph (f)(2)(iii)(A) of this section is equal to or greater than 95.0 percent or is equal to or greater than the minimum percent reduction necessary to meet the BTEX emission limit as determined in paragraph (f)(1) of this section.

* * * * *

(3) Compliance is achieved based on the applicable criteria in paragraphs (f)(3)(i) or (ii) of this section.

(i) For sources meeting the HAP emission reduction specified in § 63.1281(d)(1)(ii) or (e)(3) if the average HAP emission reduction calculated in paragraph (f)(2)(iii) of this section is equal to or greater than 95.0 percent.

(ii) For sources required to meet the BTEX limit under § 63.1281(e)(3) or (f)(1), compliance is achieved if the average BTEX emission reduction calculated in paragraph (f)(2)(iii) of this section is equal to or greater than the minimum percent reduction identified in paragraph (f)(1) of this section.

(g) *Performance testing for combustion control devices—manufacturers' performance test.*

(1) This paragraph (g) applies to the performance testing of a combustion control device conducted by the device manufacturer. The manufacturer shall demonstrate that a specific model of control device achieves the performance requirements in (g)(7) of this section by conducting a performance test as specified in paragraphs (g)(2) through (6) of this section.

(2) Performance testing shall consist of three one-hour (or longer) test runs for each of the four following firing rate settings making a total of 12 test runs per test. Propene (propylene) gas shall be used for the testing fuel. All fuel analyses shall be performed by an independent third-party laboratory (not affiliated with the control device manufacturer or fuel supplier).

(i) 90–100 percent of maximum design rate (fixed rate).

(ii) 70–100–70 percent (ramp up, ramp down). Begin the test at 70 percent of the maximum design rate. During the first 5 minutes, incrementally ramp the firing rate to 100 percent of the maximum design rate. Hold at 100 percent for 5 minutes. In the 10–15 minute time range, incrementally ramp back down to 70 percent of the maximum design rate. Repeat three more times for a total of 60 minutes of sampling.

(iii) 30–70–30 percent (ramp up, ramp down). Begin the test at 30 percent of the maximum design rate. During the first 5 minutes, incrementally ramp the firing rate to 70 percent of the maximum design rate. Hold at 70 percent for 5 minutes. In the 10–15 minute time range, incrementally ramp back down to 30 percent of the maximum design rate. Repeat three more times for a total of 60 minutes of sampling.

(iv) 0–30–0 percent (ramp up, ramp down). Begin the test at 0 percent of the maximum design rate. During the first 5 minutes, incrementally ramp the firing rate to 30 percent of the maximum design rate. Hold at 30 percent for 5 minutes. In the 10–15 minute time range, incrementally ramp back down to 0 percent of the maximum design rate. Repeat three more times for a total of 60 minutes of sampling.

(3) All models employing multiple enclosures shall be tested simultaneously and with all burners operational. Results shall be reported for each enclosure individually and for the average of the emissions from all interconnected combustion enclosures/chambers. Control device operating data shall be collected continuously throughout the performance test using an electronic Data Acquisition System and strip chart. Data shall be submitted with the test report in accordance with paragraph (g)(8)(iii) of this section.

(4) Inlet testing shall be conducted as specified in paragraphs (g)(4)(i) through (iii) of this section.

(i) The inlet gas flow metering system shall be located in accordance with Method 2A, 40 CFR part 60, appendix A–1, (or other approved procedure) to measure inlet gas flowrate at the control device inlet location. The fitting for filling fuel sample containers shall be located a minimum of 8 pipe diameters upstream of any inlet gas flow monitoring meter.

(ii) Inlet gas flowrate shall be determined using Method 2A, 40 CFR part 60, appendix A–1. Record the start and stop reading for each 60-minute THC test. Record the inlet gas pressure and temperature at 5-minute intervals throughout each 60-minute THC test.

(iii) Inlet gas sampling shall be conducted in accordance with the criteria in paragraphs (g)(4)(iii)(A) and (B) of this section.

(A) At the inlet gas sampling location, securely connect a Silonite-coated stainless steel evacuated canister fitted with a flow controller sufficient to fill the canister over a 3 hour period. Filling shall be conducted as specified in the following:

(*1*) Open the canister sampling valve at the beginning of the total hydrocarbon (THC) test, and close the canister at the end of each THC test run.

(*2*) Fill one canister across the three test runs for each THC test such that one composite fuel sample exists for each test condition.

(*3*) Label the canisters individually and record on a chain of custody form.

(B) Each inlet gas sample shall be analyzed using the following methods. The results shall be included in the test report.

(*1*) Hydrocarbon compounds containing between one and five atoms of carbon plus benzene using ASTM D1945–03 (Reapproved 2010) (incorporated by reference as specified in § 63.14).

(*2*) Hydrogen (H_2), carbon monoxide (CO), carbon dioxide (CO_2), nitrogen (N_2), oxygen (O_2) using ASTM D1945–03 (Reapproved 2010) (incorporated by reference as specified in § 63.14).

(*3*) Higher heating value using ASTM D3588–98 (Reapproved 2003) or ASTM D4891–89 (Reapproved 2006) (incorporated by reference as specified in § 63.14).

(5) Outlet testing shall be conducted in accordance with the criteria in paragraphs (g)(5)(i) through (v) of this section.

(i) Sampling and flowrate measured in accordance with the following:

(A) The outlet sampling location shall be a minimum of 4 equivalent stack diameters downstream from the highest peak flame or any other flow disturbance, and a minimum of one equivalent stack diameter upstream of the exit or any other flow disturbance. A minimum of two sample ports shall be used.

(B) Flowrate shall be measured using Method 1, 40 CFR part 60, Appendix 1, for determining flow measurement traverse point location; and Method 2, 40 CFR part 60, Appendix 1, shall be used to measure duct velocity. If low flow conditions are encountered (*i.e.,* velocity pressure differentials less than 0.05 inches of water) during the performance test, a more sensitive manometer or other pressure measurement device shall be used to obtain an accurate flow profile.

(ii) Molecular weight shall be determined as specified in paragraphs (g)(4)(iii)(B), and (g)(5)(ii)(A) and (B) of this section.

(A) An integrated bag sample shall be collected during the Method 4, 40 CFR part 60, Appendix A, moisture test. Analyze the bag sample using a gas chromatograph-thermal conductivity detector (GC–TCD) analysis meeting the following criteria:

(*1*) Collect the integrated sample throughout the entire test, and collect representative volumes from each traverse location.

(*2*) The sampling line shall be purged with stack gas before opening the valve and beginning to fill the bag.

(*3*) The bag contents shall be vigorously mixed prior to the GC analysis.

(*4*) The GC–TCD calibration procedure in Method 3C, 40 CFR part 60, Appendix A, shall be modified by using EPAAlt–045 as follows: For the initial calibration, triplicate injections of any single concentration must agree within 5 percent of their mean to be valid. The calibration response factor for a single concentration re-check must be within 10 percent of the original calibration response factor for that concentration. If this criterion is not met, the initial calibration using at least three concentration levels shall be repeated.

(B) Report the molecular weight of: O_2, CO_2, methane (CH4), and N_2 and include in the test report submitted under § 63.775(d)(iii). Moisture shall be determined using Method 4, 40 CFR part 60, Appendix A. Traverse both ports with the Method 4, 40 CFR part 60, Appendix A, sampling train during each test run. Ambient air shall not be

introduced into the Method 3C, 40 CFR part 60, Appendix A, integrated bag sample during the port change.

(iii) Carbon monoxide shall be determined using Method 10, 40 CFR part 60, Appendix A or ASTM D6522–00 (Reapproved 2005) (incorporated by reference as specified in § 63.14). The test shall be run at the same time and with the sample points used for the EPA Method 25A, 40 CFR part 60, Appendix A, testing. An instrument range of 0–10 per million by volume-dry (ppmvd) shall be used.

(iv) Visible emissions shall be determined using Method 22, 40 CFR part 60, Appendix A. The test shall be performed continuously during each test run. A digital color photograph of the exhaust point, taken from the position of the observer and annotated with date and time, will be taken once per test run and the four photos included in the test report.

(v) Excess air shall be determined using resultant data from the EPA Method 3C tests and EPA Method 3B, 40 CFR part 60, Appendix A, equation 3B–1 or ANSI/ASME PTC 19.10–1981, Part 10 (manual portion only) (incorporated by reference as specified in § 63.14).

(6) Total hydrocarbons (THC) shall be determined as specified by the following criteria:

(i) Conduct THC sampling using Method 25A, 40 CFR part 60, Appendix A, except the option for locating the probe in the center 10 percent of the stack shall not be allowed. The THC probe must be traversed to 16.7 percent, 50 percent, and 83.3 percent of the stack diameter during the test run.

(ii) A valid test shall consist of three Method 25A, 40 CFR part 60, Appendix A, tests, each no less than 60 minutes in duration.

(iii) A 0–10 parts per million by volume-wet (ppmvw) (as propane) measurement range is preferred; as an alternative a 0–30 ppmvw (as carbon) measurement range may be used.

(iv) Calibration gases will be propane in air and be certified through EPA Protocol 1—''EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards,'' September 1997, as amended August 25, 1999, EPA–600/R–97/121 (or more recent if updated since 1999).

(v) THC measurements shall be reported in terms of ppmvw as propane.

(vi) THC results shall be corrected to 3 percent CO_2, as measured by Method 3C, 40 CFR part 60, Appendix A.

(vii) Subtraction of methane/ethane from the THC data is not allowed in determining results.

(7) Performance test criteria:

(i) The control device model tested must meet the criteria in paragraphs (g)(7)(i)(A) through (C) of this section:

(A) Method 22, 40 CFR part 60, Appendix A, results under paragraph (g)(5)(v) of this section with no indication of visible emissions, and

(B) Average Method 25A, 40 CFR part 60, Appendix A, results under paragraph (g)(6) of this section equal to or less than 10.0 ppmvw THC as propane corrected to 3.0 percent CO_2, and

(C) Average CO emissions determined under paragraph (g)(5)(iv) of this section equal to or less than 10 parts ppmvd, corrected to 3.0 percent CO_2.

(D) Excess combustion air shall be equal to or greater than 150 percent.

(ii) The manufacturer shall determine a maximum inlet gas flowrate which shall not be exceeded for each control device model to achieve the criteria in paragraph (g)(7)(i) of this section.

(iii) A control device meeting the criteria in paragraph (g)(7)(i)(A) through (C) of this section will have demonstrated a destruction efficiency of 95.0 percent for HAP regulated under this subpart.

(8) The owner or operator of a combustion control device model tested under this section shall submit the information listed in paragraphs (g)(8)(i) through (iii) in the test report required under § 63.775(d)(1)(iii).

(i) Full schematic of the control device and dimensions of the device components.

(ii) Design net heating value (minimum and maximum) of the device.

(iii) Test fuel gas flow range (in both mass and volume). Include the minimum and maximum allowable inlet gas flowrate.

(iv) Air/stream injection/assist ranges, if used.

(v) The test parameter ranges listed in paragraphs (g)(8)(v)(A) through (O) of this section, as applicable for the tested model.

(A) Fuel gas delivery pressure and temperature.

(B) Fuel gas moisture range.

(C) Purge gas usage range.

(D) Condensate (liquid fuel) separation range.

(E) Combustion zone temperature range. This is required for all devices that measure this parameter.

(F) Excess combustion air range.

(G) Flame arrestor(s).

(H) Burner manifold pressure.

(I) Pilot flame sensor.

(J) Pilot flame design fuel and fuel usage.

(K) Tip velocity range.

(L) Momentum flux ratio.

(M) Exit temperature range.

(N) Exit flowrate.

(O) Wind velocity and direction.

(vi) The test report shall include all calibration quality assurance/quality control data, calibration gas values, gas cylinder certification, and strip charts annotated with test times and calibration values.

(h) *Compliance demonstration for combustion control devices—manufacturers' performance test.* This paragraph applies to the demonstration of compliance for a combustion control device tested under the provisions in paragraph (g) of this section. Owners or operators shall demonstrate that a control device achieves the performance requirements of § 63.1281(d)(1), (e)(3)(ii) or (f)(1), by installing a device tested under paragraph (g) of this section and complying with the following criteria:

(1) The inlet gas flowrate shall meet the range specified by the manufacturer. Flowrate shall be calculated as specified in § 63.1283(d)(3)(i)(H)(*1*).

(2) A pilot flame shall be present at all times of operation. The pilot flame shall be monitored in accordance with § 63.1283(d)(3)(i)(H)(*2*).

(3) Devices shall be operated with no visible emissions, except for periods not to exceed a total of 2 minutes during any hour. A visible emissions test using Method 22, 40 CFR part 60, Appendix A, shall be performed each calendar quarter. The observation period shall be 1 hour and shall be conducted according to EPA Method 22, 40 CFR part 60, Appendix A.

(4) Compliance with the operating parameter limit is achieved when the following criteria are met:

(i) The inlet gas flowrate monitored under paragraph (h)(1) of this section is equal to or below the maximum established by the manufacturer; and

(ii) The pilot flame is present at all times; and

(iii) During the visible emissions test performed under paragraph (h)(3) of this section the duration of visible emissions does not exceed a total of 2 minutes during the observation period. Devices failing the visible emissions test shall follow manufacturers repair instructions, if available, or best combustion engineering practice as outlined in the unit inspection and maintenance plan, to return the unit to compliant operation. All repairs and maintenance activities for each unit shall be recorded in a maintenance and repair log and shall be available on site for inspection.

(iv) Following return to operation from maintenance or repair activity, each device must pass a Method 22 visual observation as described in paragraph (h)(3) of this section.

■ 30. Section 63.1283 is amended by:
■ a. Adding paragraph (b);
■ b. Revising paragraph (d)(1) introductory text;
■ c. Revising paragraph (d)(1)(ii) and adding paragraphs (d)(1)(iii) and (iv);
■ d. Revising paragraph (d)(2);
■ e. Revising paragraph (d)(3)(i)(A);
■ f. Revising paragraph (d)(3)(i)(D);
■ g. Revising paragraph (d)(3)(i)(G);
■ h. Adding paragraph (d)(3)(i)(H);
■ i. Revising paragraph (d)(4);
■ j. Revising paragraph (d)(5)(i);
■ k. Revising paragraphs (d)(5)(ii)(A) through (C);
■ l. Revising paragraph (d)(6) introductory text;
■ m. Revising paragraph (d)(6)(ii);
■ n. Adding paragraph (d)(6)(v);
■ o. Revising paragraph (d)(7); and
■ p. Removing and reserving paragraph (d)(8).

The additions and revisions read as follows:

§ 63.1283 Inspection and monitoring requirements.

* * * * *

(b) The owner or operator of a control device whose model was tested under 63.1282(g) shall develop an inspection and maintenance plan for each control device. At a minimum, the plan shall contain the control device manufacturer's recommendations for ensuring proper operation of the device. Semi-annual inspections shall be conducted for each control device with maintenance and replacement of control device components made in accordance with the plan.

* * * * *

(d) *Control device monitoring requirements.* (1) For each control device except as provided for in paragraph (d)(2) of this section, the owner or operator shall install and operate a continuous parameter monitoring system in accordance with the requirements of paragraphs (d)(3) through (7) of this section. Owners or operators that install and operate a flare in accordance with § 63.1281(d)(1)(iii) or (f)(1)(iii) are exempt from the requirements of paragraphs (d)(4) and (5) of this section. The continuous monitoring system shall be designed and operated so that a determination can be made on whether the control device is achieving the applicable performance requirements of § 63.1281(d), (e)(3), or (f)(1). Each continuous parameter monitoring system shall meet the following specifications and requirements:

* * * * *

(ii) A site-specific monitoring plan must be prepared that addresses the monitoring system design, data collection, and the quality assurance and quality control elements outlined in paragraph (d) of this section and in § 63.8(d). Each CPMS must be installed, calibrated, operated, and maintained in accordance with the procedures in your approved site-specific monitoring plan. Using the process described in § 63.8(f)(4), you may request approval of monitoring system quality assurance and quality control procedures alternative to those specified in paragraphs (d)(1)(ii)(A) through (E) of this section in your site-specific monitoring plan.

(A) The performance criteria and design specifications for the monitoring system equipment, including the sample interface, detector signal analyzer, and data acquisition and calculations;

(B) Sampling interface (*e.g.*, thermocouple) location such that the monitoring system will provide representative measurements;

(C) Equipment performance checks, system accuracy audits, or other audit procedures;

(D) Ongoing operation and maintenance procedures in accordance with provisions in § 63.8(c)(1) and (c)(3); and

(E) Ongoing reporting and recordkeeping procedures in accordance with provisions in § 63.10(c), (e)(1), and (e)(2)(i).

(iii) The owner or operator must conduct the CPMS equipment performance checks, system accuracy audits, or other audit procedures specified in the site-specific monitoring plan at least once every 12 months.

(iv) The owner or operator must conduct a performance evaluation of each CPMS in accordance with the site-specific monitoring plan.

(2) An owner or operator is exempted from the monitoring requirements specified in paragraphs (d)(3) through (7) of this section for the following types of control devices:

(i) Except for control devices for small glycol dehydration units, a boiler or process heater in which all vent streams are introduced with the primary fuel or are used as the primary fuel;

(ii) Except for control devices for small glycol dehydration units, a boiler or process heater with a design heat input capacity equal to or greater than 44 megawatts.

(3) * * *

(i) * * *

(A) For a thermal vapor incinerator that demonstrates during the performance test conducted under § 63.1282(d) that combustion zone temperature is an accurate indicator of performance, a temperature monitoring device equipped with a continuous recorder. The monitoring device shall have a minimum accuracy of ±2 percent of the temperature being monitored in °C, or ±2.5 °C, whichever value is greater. The temperature sensor shall be installed at a location representative of the combustion zone temperature.

* * * * *

(D) For a boiler or process heater, a temperature monitoring device equipped with a continuous recorder. The temperature monitoring device shall have a minimum accuracy of ±2 percent of the temperature being monitored in °C, or ±2.5 °C, whichever value is greater. The temperature sensor shall be installed at a location representative of the combustion zone temperature.

* * * * *

(G) For a nonregenerative-type carbon adsorption system, the owner or operator shall monitor the design carbon replacement interval established using a performance test performed in accordance with § 63.1282(d)(3) and shall be based on the total carbon working capacity of the control device and source operating schedule.

(H) For a control device whose model is tested under § 63.1282(g):

(*1*) The owner or operator shall determine actual average inlet waste gas flowrate using the model GRI–GLYCalc™, Version 3.0 or higher, ProMax, or AspenTech HYSYS. Inputs to the models shall be representative of actual operating conditions of the controlled unit. The determination shall be performed to coincide with the visible emissions test under § 63.1282(h)(3);

(*2*) A heat sensing monitoring device equipped with a continuous recorder that indicates the continuous ignition of the pilot flame.

* * * * *

(4) Using the data recorded by the monitoring system, except for inlet gas flowrate, the owner or operator must calculate the daily average value for each monitored operating parameter for each operating day. If the emissions unit operation is continuous, the operating day is a 24-hour period. If the emissions unit operation is not continuous, the operating day is the total number of hours of control device operation per 24-hour period. Valid data points must be available for 75 percent of the operating hours in an operating day to compute the daily average.

(5) * * *

(i) The owner or operator shall establish a minimum operating parameter value or a maximum operating parameter value, as appropriate for the control device, to

define the conditions at which the control device must be operated to continuously achieve the applicable performance requirements of § 63.1281(d)(1), (e)(3)(ii), or (f)(1). Each minimum or maximum operating parameter value shall be established as follows:

(A) If the owner or operator conducts performance tests in accordance with the requirements of § 63.1282(d)(3) to demonstrate that the control device achieves the applicable performance requirements specified in § 63.1281(d)(1), (e)(3)(ii), or (f)(1), then the minimum operating parameter value or the maximum operating parameter value shall be established based on values measured during the performance test and supplemented, as necessary, by a condenser design analysis or control device manufacturer's recommendations or a combination of both.

(B) If the owner or operator uses a condenser design analysis in accordance with the requirements of § 63.1282(d)(4) to demonstrate that the control device achieves the applicable performance requirements specified in § 63.1281(d)(1), (e)(3)(ii), or (f)(1), then the minimum operating parameter value or the maximum operating parameter value shall be established based on the condenser design analysis and may be supplemented by the condenser manufacturer's recommendations.

(C) If the owner or operator operates a control device where the performance test requirement was met under § 63.1282(g) to demonstrate that the control device achieves the applicable performance requirements specified in § 63.1281(d)(1), (e)(3)(ii) or (f)(1), then the maximum inlet gas flowrate shall be established based on the performance test and supplemented, as necessary, by the manufacturer recommendations.

(ii) * * *

(A) If the owner or operator conducts a performance test in accordance with the requirements of § 63.1282(d)(3) to demonstrate that the condenser achieves the applicable performance requirements in § 63.1281(d)(1), (e)(3)(ii), or (f)(1), then the condenser performance curve shall be based on values measured during the performance test and supplemented as necessary by control device design analysis, or control device manufacturer's recommendations, or a combination or both.

(B) If the owner or operator uses a control device design analysis in accordance with the requirements of § 63.1282(d)(4)(i) to demonstrate that the condenser achieves the applicable performance requirements specified in § 63.1281(d)(1), (e)(3)(ii), or (f)(1), then the condenser performance curve shall be based on the condenser design analysis and may be supplemented by the control device manufacturer's recommendations.

(C) As an alternative to paragraph (d)(5)(ii)(B) of this section, the owner or operator may elect to use the procedures documented in the GRI report entitled, "Atmospheric Rich/Lean Method for Determining Glycol Dehydrator Emissions" (GRI–95/0368.1) as inputs for the model GRI–GLYCalc™, Version 3.0 or higher, to generate a condenser performance curve.

(6) An excursion for a given control device is determined to have occurred when the monitoring data or lack of monitoring data result in any one of the criteria specified in paragraphs (d)(6)(i) through (d)(6)(v) of this section being met. When multiple operating parameters are monitored for the same control device and during the same operating day, and more than one of these operating parameters meets an excursion criterion specified in paragraphs (d)(6)(i) through (d)(6)(v) of this section, then a single excursion is determined to have occurred for the control device for that operating day.

* * * * *

(ii) For sources meeting § 63.1281(d)(1)(ii), an excursion occurs when average condenser efficiency calculated according to the requirements specified in § 63.1282(f)(2)(iii) is less than 95.0 percent, as specified in § 63.1282(f)(3). For sources meeting § 63.1281(f)(1), an excursion occurs when the 30-day average condenser efficiency calculated according to the requirements of § 63.1282(f)(2)(iii) is less than the identified 30-day required percent reduction.

* * * * *

(v) For control device whose model is tested under § 63.1282(g) an excursion occurs when:

(A) The inlet gas flowrate exceeds the maximum established during the test conducted under § 63.1282(g).

(B) Failure of the quarterly visible emissions test conducted under § 63.1282(h)(3) occurs.

(7) For each excursion, the owner or operator shall be deemed to have failed to have applied control in a manner that achieves the required operating parameter limits. Failure to achieve the required operating parameter limits is a violation of this standard.

(8) [Reserved]

* * * * *

■ 31. Section 63.1284 is amended by:

■ a. Revising paragraph (b)(3) introductory text;

■ b. Removing and reserving paragraph (b)(3)(ii);

■ c. Revising paragraph (b)(4)(ii);

■ d. Revising paragraph (b)(4)(iii);

■ e. Adding paragraph (b)(7)(ix); and

■ f. Adding paragraphs (f), (g) and (h).

The revisions and additions read as follows:

§ 63.1284 Recordkeeping requirements.

* * * * *

(b) * * *

(3) Records specified in § 63.10(c) for each monitoring system operated by the owner or operator in accordance with the requirements of § 63.1283(d). Notwithstanding the previous sentence, monitoring data recorded during periods identified in paragraphs (b)(3)(i) through (iv) of this section shall not be included in any average or percent leak rate computed under this subpart. Records shall be kept of the times and durations of all such periods and any other periods during process or control device operation when monitors are not operating or failed to collect required data.

* * * * *

(ii) [Reserved]

* * * * *

(4) * * *

(ii) Records of the daily average value of each continuously monitored parameter for each operating day determined according to the procedures specified in § 63.1283(d)(4) of this subpart, except as specified in paragraphs (b)(4)(ii)(A) through (C) of this section.

(A) For flares, the records required in paragraph (e) of this section.

(B) For condensers installed to comply with § 63.1275, records of the annual 30-day rolling average condenser efficiency determined under § 63.1282(f) shall be kept in addition to the daily averages.

(C) For a control device whose model is tested under § 63.1282(g), the records required in paragraph (g) of this section.

(iii) Hourly records of the times and durations of all periods when the vent stream is diverted from the control device or the device is not operating.

* * * * *

(7) * * *

(ix) Records identifying the carbon replacement schedule under § 63.1281(d)(5) and records of each carbon replacement.

* * * * *

(f) The owner or operator of an affected source subject to this subpart shall maintain records of the occurrence and duration of each malfunction of

operation (*i.e.,* process equipment) or the air pollution control equipment and monitoring equipment. The owner or operator shall maintain records of actions taken during periods of malfunction to minimize emissions in accordance with § 63.1274(h), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation.

(g) Record the following when using a control device whose model is tested under § 63.1282(g) to comply with § 63.1281(d), (e)(3)(ii) and (f)(1):

(1) All visible emission readings and flowrate calculations made during the compliance determination required by § 63.1282(h); and

(2) All hourly records and other recorded periods when the pilot flame is absent.

(h) The date the semi-annual maintenance inspection required under § 63.1283(b) is performed. Include a list of any modifications or repairs made to the control device during the inspection and other maintenance performed such as cleaning of the fuel nozzles.

■ 32. Section 63.1285 is amended by:
■ a. Revising paragraph (b)(1);
■ b. Revising paragraph (b)(6);
■ c. Removing paragraph (b)(7);
■ d. Revising paragraph (d) introductory text;
■ e. Revising paragraph (d)(1) introductory text;
■ f. Revising paragraph (d)(1)(i);
■ g. Revising paragraph (d)(1)(ii) introductory text;
■ h. Revising paragraph (d)(2) introductory text;
■ i. Revising paragraph (d)(4) introductory text;
■ j. Revising paragraph (d)(4)(ii);
■ k. Adding paragraph (d)(4)(iv);
■ l. Revising paragraph (d)(10);
■ m. Adding paragraphs (d)(11) and (d)(12);
■ n. Revising paragraph (e)(2) introductory text;
■ o. Revising paragraph (e)(2)(ii)(B);
■ p. Adding paragraphs (e)(2)(ii)(D) and (E);
■ q. Adding paragraphs (e)(2)(x) through (xiii); and
■ r. Adding paragraph (g).

The revisions and additions read as follows:

§ 63.1285 Reporting requirements.

* * * * *

(b) * * *

(1) The initial notifications required for existing affected sources under § 63.9(b)(2) shall be submitted as provided in paragraphs (b)(1)(i) and (ii) of this section.

(i) Except as otherwise provided in paragraph (b)(1)(ii) of this section, the initial notification shall be submitted by 1 year after an affected source becomes subject to the provisions of this subpart or by June 17, 2000, whichever is later. Affected sources that are major sources on or before June 17, 2000 and plan to be area sources by June 17, 2002 shall include in this notification a brief, nonbinding description of a schedule for the action(s) that are planned to achieve area source status.

(ii) An affected source identified under § 63.1270(d)(3) shall submit an initial notification required for existing affected sources under § 63.9(b)(2) within 1 year after the affected source becomes subject to the provisions of this subpart or by October 15, 2013, whichever is later. An affected source identified under § 63.1270(d)(3) that plans to be an area source by October 15, 2015, shall include in this notification a brief, nonbinding description of a schedule for the action(s) that are planned to achieve area source status.

* * * * *

(6) If there was a malfunction during the reporting period, the Periodic Report specified in paragraph (e) of this section shall include the number, duration, and a brief description for each type of malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded. The report must also include a description of actions taken by an owner or operator during a malfunction of an affected source to minimize emissions in accordance with § 63.1274(h), including actions taken to correct a malfunction.

* * * * *

(d) Each owner or operator of a source subject to this subpart shall submit a Notification of Compliance Status Report as required under § 63.9(h) within 180 days after the compliance date specified in § 63.1270(d). In addition to the information required under § 63.9(h), the Notification of Compliance Status Report shall include the information specified in paragraphs (d)(1) through (12) of this section. This information may be submitted in an operating permit application, in an amendment to an operating permit application, in a separate submittal, or in any combination of the three. If all of the information required under this paragraph have been submitted at any time prior to 180 days after the applicable compliance dates specified in § 63.1270(d), a separate Notification of Compliance Status Report is not required. If an owner or operator submits the information specified in paragraphs (d)(1) through (12) of this section at different times, and/or different submittals, subsequent submittals may refer to previous submittals instead of duplicating and resubmitting the previously submitted information.

(1) If a closed-vent system and a control device other than a flare are used to comply with § 63.1274, the owner or operator shall submit the information in paragraph (d)(1)(iii) of this section and the information in either paragraph (d)(1)(i) or (ii) of this section.

(i) The condenser design analysis documentation specified in § 63.1282(d)(4) of this subpart if the owner or operator elects to prepare a design analysis; or

(ii) If the owner or operator is required to conduct a performance test, the performance test results including the information specified in paragraphs (d)(1)(ii)(A) and (B) of this section. Results of a performance test conducted prior to the compliance date of this subpart can be used provided that the test was conducted using the methods specified in § 63.1282(d)(3), and that the test conditions are representative of current operating conditions. If the owner or operator operates a combustion control device model tested under § 63.1282(g), an electronic copy of the performance test results shall be submitted via email to *Oil_and_Gas_PT@EPA.GOV* unless the test results for that model of combustion control device are posted at the following Web site: *epa.gov/airquality/oilandgas/.*

* * * * *

(2) If a closed-vent system and a flare are used to comply with § 63.1274, the owner or operator shall submit performance test results including the information in paragraphs (d)(2)(i) and (ii) of this section. The owner or operator shall also submit the information in paragraph (d)(2)(iii) of this section.

* * * * *

(4) For each control device other than a flare used to meet the requirements of § 63.1274, the owner or operator shall submit the information specified in paragraphs (d)(4)(i) through (iv) of this section for each operating parameter required to be monitored in accordance with the requirements of § 63.1283(d).

* * * * *

(ii) An explanation of the rationale for why the owner or operator selected each of the operating parameter values established in § 63.1283(d)(5) of this subpart. This explanation shall include

any data and calculations used to develop the value, and a description of why the chosen value indicates that the control device is operating in accordance with the applicable requirements of § 63.1281(d)(1), (e)(3)(ii), or (f)(1).

* * * * *

(iv) For each carbon adsorber, the predetermined carbon replacement schedule as required in § 63.1281(d)(5)(i).

* * * * *

(10) The owner or operator shall submit the analysis prepared under § 63.1281(e)(2) to demonstrate that the conditions by which the facility will be operated to achieve the HAP emission reduction of 95.0 percent, or the BTEX limit in § 63.1275(b)(1)(iii) through process modifications or a combination of process modifications and one or more control devices.

(11) If the owner or operator installs a combustion control device model tested under the procedures in § 63.1282(g), the data listed under § 63.1282(g)(8).

(12) For each combustion control device model tested under § 63.1282(g), the information listed in paragraphs (d)(12)(i) through (vi) of this section.

(i) Name, address and telephone number of the control device manufacturer.

(ii) Control device model number.

(iii) Control device serial number.

(iv) Date the model of control device was tested by the manufacturer.

(v) Manufacturer's HAP destruction efficiency rating.

(vi) Control device operating parameters, maximum allowable inlet gas flowrate.

* * * * *

(e) * * *

(2) The owner or operator shall include the information specified in paragraphs (e)(2)(i) through (xiii) of this section, as applicable.

* * * * *

(ii) * * *

(B) For each excursion caused when the 30-day average condenser control efficiency is less than the value, as specified in § 63.1283(d)(6)(ii), the report must include the 30-day average values of the condenser control efficiency, and the date and duration of the period that the excursion occurred.

* * * * *

(D) For each excursion caused when the maximum inlet gas flowrate identified under § 63.1282(g) is exceeded, the report must include the values of the inlet gas identified and the date and duration of the period that the excursion occurred.

(E) For each excursion caused when visible emissions determined under § 63.1282(h) exceed the maximum allowable duration, the report must include the date and duration of the period that the excursion occurred, repairs affected to the unit, and date the unit was returned to service.

* * * * *

(x) The results of any periodic test as required in § 63.1282(d)(3) conducted during the reporting period.

(xi) For each carbon adsorber used to meet the control device requirements of § 63.1281(d)(1), records of each carbon replacement that occurred during the reporting period.

(xii) For combustion control device inspections conducted in accordance with § 63.1283(b) the records specified in § 63.1284(h).

(xiii) Certification by a responsible official of truth, accuracy, and completeness. This certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

* * * * *

(g) *Electronic reporting.* (1) Within 60 days after the date of completing each performance test (defined in § 63.2) as required by this subpart you must submit the results of the performance tests required by this subpart to EPA's WebFIRE database by using the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX)(*www.epa.gov/cdx*). Performance test data must be submitted in the file format generated through use of EPA's Electronic Reporting Tool (ERT) (see *http://www.epa.gov/ttn/chief/ert/index.html*). Only data collected using test methods on the ERT Web site are subject to this requirement for submitting reports electronically to WebFIRE. Owners or operators who claim that some of the information being submitted for performance tests is confidential business information (CBI) must submit a complete ERT file including information claimed to be CBI on a compact disk or other commonly used electronic storage media (including, but not limited to, flash drives) to EPA. The electronic media must be clearly marked as CBI and mailed to U.S. EPA/OAPQS/CORE CBI Office, Attention: WebFIRE Administrator, MD C404–02, 4930 Old Page Rd., Durham, NC 27703. The same ERT file with the CBI omitted must be submitted to EPA via CDX as described earlier in this paragraph. At the discretion of the delegated authority, you must also submit these reports, including the confidential business information, to the delegated authority in the format specified by the delegated authority.

(2) All reports required by this subpart not subject to the requirements in paragraph (g)(1) of this section must be sent to the Administrator at the appropriate address listed in § 63.13. The Administrator or the delegated authority may request a report in any form suitable for the specific case (*e.g.,* by commonly used electronic media such as Excel spreadsheet, on CD or hard copy). The Administrator retains the right to require submittal of reports subject to paragraph (g)(1) of this section in paper format.

■ 33. Section 63.1287 is amended by revising paragraph (a) to read as follows:

§ 63.1287 Alternative means of emission limitation.

(a) If, in the judgment of the Administrator, an alternative means of emission limitation will achieve a reduction in HAP emissions at least equivalent to the reduction in HAP emissions from that source achieved under the applicable requirements in §§ 63.1274 through 63.1281, the Administrator will publish a notice in the **Federal Register** permitting the use of the alternative means for purposes of compliance with that requirement. The notice may condition the permission on requirements related to the operation and maintenance of the alternative means.

* * * * *

■ 34. Appendix to Subpart HHH of Part 63—Table is amended by revising Table 2 to read as follows:

Appendix to Subpart HHH of Part 63—Tables

* * * * *

TABLE 2 TO SUBPART HHH OF PART 63—APPLICABILITY OF 40 CFR PART 63 GENERAL PROVISIONS TO SUBPART HHH

General provisions reference	Applicable to subpart HHH	Explanation
§ 63.1(a)(1)	Yes.	
§ 63.1(a)(2)	Yes.	
§ 63.1(a)(3)	Yes.	
§ 63.1(a)(4)	Yes.	
§ 63.1(a)(5)	No	Section reserved.
§ 63.1(a)(6) through (a)(8)	Yes.	
§ 63.1(a)(9)	No	Section reserved.
§ 63.1(a)(10)	Yes.	
§ 63.1(a)(11)	Yes.	
§ 63.1(a)(12)	Yes.	
§ 63.1(b)(1)	No	Subpart HHH specifies applicability.
§ 63.1(b)(2)	Yes.	
§ 63.1(b)(3)	No.	
§ 63.1(c)(1)	No	Subpart HHH specifies applicability.
§ 63.1(c)(2)	No.	
§ 63.1(c)(3)	No	Section reserved.
§ 63.1(c)(4)	Yes.	
§ 63.1(c)(5)	Yes.	
§ 63.1(d)	No	Section reserved.
§ 63.1(e)	Yes.	
§ 63.2	Yes	Except definition of major source is unique for this source category and there are additional definitions in subpart HHH.
§ 63.3(a) through (c)	Yes.	
§ 63.4(a)(1)	Yes.	
§ 63.4(a)(2)	Yes.	
§ 63.4(a)(3)	No	Section reserved.
§ 63.4(a)(4)	No	Section reserved.
§ 63.4(a)(5)	No	Section reserved.
§ 63.4(b)	Yes.	
§ 63.4(c)	Yes.	
§ 63.5(a)(1)	Yes.	
§ 63.5(a)(2)	No	Preconstruction review required only for major sources that commence construction after promulgation of the standard.
§ 63.5(b)(1)	Yes.	
§ 63.5(b)(2)	No	Section reserved.
§ 63.5(b)(3)	Yes.	
§ 63.5(b)(4)	Yes.	
§ 63.5(b)(5)	No	Section reserved.
§ 63.5(b)(6)	Yes.	
§ 63.5(c)	No	Section reserved.
§ 63.5(d)(1)	Yes.	
§ 63.5(d)(2)	Yes.	
§ 63.5(d)(3)	Yes.	
§ 63.5(d)(4)	Yes.	
§ 63.5(e)	Yes.	
§ 63.5(f)(1)	Yes.	
§ 63.5(f)(2)	Yes.	
§ 63.6(a)	Yes.	
§ 63.6(b)(1)	Yes.	
§ 63.6(b)(2)	Yes.	
§ 63.6(b)(3)	Yes.	
§ 63.6(b)(4)	Yes.	
§ 63.6(b)(5)	Yes.	
§ 63.6(b)(6)	No	Section reserved.
§ 63.6(b)(7)	Yes.	
§ 63.6(c)(1)	Yes.	
§ 63.6(c)(2)	Yes.	
§ 63.6(c)(3) and (c)(4)	No	Section reserved.
§ 63.6(c)(5)	Yes.	
§ 63.6(d)	No	Section reserved.
§ 63.6(e)	Yes.	
§ 63.6(e)	Yes	Except as otherwise specified.
§ 63.6(e)(1)(i)	No	See § 63.1274(h) for general duty requirement.
§ 63.6(e)(1)(ii)	No.	
§ 63.6(e)(1)(iii)	Yes.	
§ 63.6(e)(2)	No	Section reserved.
§ 63.6(e)(3)	No.	
§ 63.6(f)(1)	No.	
§ 63.6(f)(2)	Yes.	
§ 63.6(f)(3)	Yes.	
§ 63.6(g)	Yes.	

TABLE 2 TO SUBPART HHH OF PART 63—APPLICABILITY OF 40 CFR PART 63 GENERAL PROVISIONS TO SUBPART HHH—Continued

General provisions reference	Applicable to subpart HHH	Explanation
§ 63.6(h)(1)	No.	
§ 63.6(h)(2)	Yes.	
§ 63.6(h)(3)	No	Section reserved.
§ 63.6(h)(4) through (h)(9)	Yes.	
§ 63.6(i)(1) through (i)(14)	Yes.	
§ 63.6(i)(15)	No	Section reserved.
§ 63.6(i)(16)	Yes.	
§ 63.6(j)	Yes.	
§ 63.7(a)(1)	Yes.	
§ 63.7(a)(2)	Yes	But the performance test results must be submitted within 180 days after the compliance date.
§ 63.7(a)(3)	Yes.	
§ 63.7(a)(4)	Yes.	
§ 63.7(b)	Yes.	
§ 63.7(c)	Yes.	
§ 63.7(d)	Yes.	
§ 63.7(e)(1)	No.	
§ 63.7(e)(2)	Yes.	
§ 63.7(e)(3)	Yes.	
§ 63.7(e)(4)	Yes.	
§ 63.7(f)	Yes.	
§ 63.7(g)	Yes.	
§ 63.7(h)	Yes.	
§ 63.8(a)(1)	Yes.	
§ 63.8(a)(2)	Yes.	
§ 63.8(a)(3)	No	Section reserved.
§ 63.8(a)(4)	Yes.	
§ 63.8(b)(1)	Yes.	
§ 63.8(b)(2)	Yes.	
§ 63.8(b)(3)	Yes.	
§ 63.8(c)(1)	Yes.	
§ 63.8(c)(1)(i)	No.	
§ 63.8(c)(1)(ii)	Yes.	
§ 63.8(c)(1)(iii)	No.	
§ 63.8(c)(2)	Yes.	
§ 63.8(c)(3)	Yes.	
§ 63.8(c)(4)	No.	
§ 63.8(c)(5) through (c)(8)	Yes.	
§ 63.8(d)(1)	Yes.	
§ 63.8(d)(2)	Yes.	
§ 63.8(d)(3)	Yes	Except for last sentence, which refers to an SSM plan. SSM plans are not required.
§ 63.8(e)	Yes	Subpart HHH does not specifically require continuous emissions monitor performance evaluations, however, the Administrator can request that one be conducted.
§ 63.8(f)(1) through (f)(5)	Yes.	
§ 63.8(f)(6)	No	Subpart HHH does not require continuous emissions monitoring.
§ 63.8(g)	No	Subpart HHH specifies continuous monitoring system data reduction requirements.
§ 63.9(a)	Yes.	
§ 63.9(b)(1)	Yes.	
§ 63.9(b)(2)	Yes	Existing sources are given 1 year (rather than 120 days) to submit this notification.
§ 63.9(b)(3)	No	Section reserved.
§ 63.9(b)(4)	Yes.	
§ 63.9(b)(5)	Yes.	
§ 63.9(c)	Yes.	
§ 63.9(d)	Yes.	
§ 63.9(e)	Yes.	
§ 63.9(f)	Yes.	
§ 63.9(g)	Yes.	
§ 63.9(h)(1) through (h)(3)	Yes.	
§ 63.9(h)(4)	No	Section reserved.
§ 63.9(h)(5) and (h)(6)	Yes.	
§ 63.9(i)	Yes.	
§ 63.9(j)	Yes.	
§ 63.10(a)	Yes.	
§ 63.10(b)(1)	Yes	Section 63.1284(b)(1) requires sources to maintain the most recent 12 months of data on-site and allows offsite storage for the remaining 4 years of data.
§ 63.10(b)(2)	Yes.	

TABLE 2 TO SUBPART HHH OF PART 63—APPLICABILITY OF 40 CFR PART 63 GENERAL PROVISIONS TO SUBPART HHH—Continued

General provisions reference	Applicable to subpart HHH	Explanation
§ 63.10(b)(2)(i)	No.	
§ 63.10(b)(2)(ii)	No	See § 63.1284(f) for recordkeeping of (1) occurrence and duration and (2) actions taken during malfunction.
§ 63.10(b)(2)(iii)	Yes.	
§ 63.10(b)(2)(iv) through (b)(2)(v)	No.	
§ 63.10(b)(2)(vi) through (b)(2)(xiv)	Yes.	
§ 63.10(b)(3)	No.	
§ 63.10(c)(1)	Yes.	
§ 63.10(c)(2) through (c)(4)	No	Sections reserved.
§ 63.10(c)(5) through (c)(8)	Yes.	
§ 63.10(c)(9)	No	Section reserved.
§ 63.10(c)(10) through (c)(11)	No	See § 63.1284(f) for recordkeeping of malfunctions.
§ 63.10(c)(12) through (c)(14)	Yes.	
§ 63.10(c)(15)	No.	
§ 63.10(d)(1)	Yes.	
§ 63.10(d)(2)	Yes.	
§ 63.10(d)(3)	Yes.	
§ 63.10(d)(4)	Yes.	
§ 63.10(d)(5)	No	See § 63.1285(b)(6) for reporting of malfunctions.
§ 63.10(e)(1)	Yes.	
§ 63.10(e)(2)	Yes.	
§ 63.10(e)(3)(i)	Yes	Subpart HHH requires major sources to submit Periodic Reports semi-annually.
§ 63.10(e)(3)(i)(A)	Yes.	
§ 63.10(e)(3)(i)(B)	Yes.	
§ 63.10(e)(3)(i)(C)	No	Section reserved.
§ 63.10(e)(3)(i)(D)	Yes.	
§ 63.10(e)(3)(ii) through (e)(3)(viii)	Yes.	
§ 63.10(f)	Yes.	
§ 63.11(a) through (e)	Yes.	
§ 63.12(a) through (c)	Yes.	
§ 63.13(a) through (c)	Yes.	
§ 63.14(a) through (q)	Yes.	
§ 63.15(a) and (b)	Yes.	

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Part III

Environmental Protection Agency

40 CFR Parts 9 and 60

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

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 9 and 60

[EPA–HQ–OAR–2007–0011; FRL–9672–3]

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: Final rule; lift stay of effective date.

SUMMARY: On June 24, 2008, the EPA promulgated amendments to the Standards of Performance for Petroleum Refineries and new standards of performance for petroleum refinery process units constructed, reconstructed or modified after May 14, 2007. The EPA subsequently received three petitions for reconsideration of these final rules. On September 26, 2008, the EPA granted reconsideration and issued a stay for the issues raised in the petitions regarding process heaters and flares. On December 22, 2008, the EPA addressed those specific issues by proposing amendments to certain provisions for process heaters and flares and extending the stay of these provisions until further notice. The EPA also proposed technical corrections to the rules for issues that were raised in the petitions for reconsideration. In this action, the EPA is finalizing those amendments and technical corrections and is lifting the stay of all the provisions granted on September 26, 2008 and extended until further notice on December 22, 2008.

DATES: The stay of the definition of ''flare'' in 40 CFR 60.101a, paragraph (g) of 40 CFR 60.102a, and paragraphs (d) and (e) of 40 CFR 60.107a is lifted and this final rule is effective on November 13, 2012. The incorporation by reference of certain publications listed in the final rule is approved by the Director of the Federal Register as of November 13, 2012.

ADDRESSES: The EPA has established a docket for this action under Docket ID No. EPA–HQ–OAR–2007–0011. 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.,* confidential business information (CBI) or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the Internet and will be publicly available only in hard copy form. 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 Air Docket is (202) 566–1742.

FOR FURTHER INFORMATION CONTACT: Ms. Brenda Shine, Office of Air Quality Planning and Standards, Sector Policies and Programs Division, Refining and Chemicals Group (E143–01), Environmental Protection Agency, Research Triangle Park, NC 27711, telephone number: (919) 541–3608; fax number: (919) 541–0246; email address: *shine.brenda@epa.gov*.

SUPPLEMENTARY INFORMATION: The information in this preamble is organized as follows:

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C. Judicial Review
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H. Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use
I. National Technology Transfer and Advancement Act
J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations
K. Congressional Review Act

I. General Information

A. Does this action apply to me?

Categories and entities potentially regulated by these final rules 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 action to a particular entity, contact the person listed in the preceding **FOR FURTHER INFORMATION CONTACT** section.

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

In addition to being available in the docket, an electronic copy of this final action is available on the World Wide Web (WWW) through the Technology Transfer Network (TTN). Following signature, a copy of this final 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.

The EPA has created a redline document comparing the existing regulatory text of 40 CFR part 60, subpart Ja and the final amendments to aid the public's ability to understand the changes to the regulatory text. This document has been placed in the docket for this rulemaking (Docket ID No. EPA–HQ–OAR–2007–0011).

C. Judicial Review

Under section 307(b)(1) of the Clean Air Act (CAA), judicial review of these final rules is available only by filing a petition for review in the United States Court of Appeals for the District of Columbia Circuit by November 13, 2012. Under section 307(b)(2) of the CAA, the requirements established by these final rules may not be challenged separately in any civil or criminal proceedings brought by the EPA to enforce these requirements.

Section 307(d)(7)(B) of the CAA further provides that "[o]nly an objection to a rule or procedure which was raised with reasonable specificity during the period for public comment (including any public hearing) may be raised during judicial review." This section also provides a mechanism for us to convene a proceeding for reconsideration, "[i]f the person raising an objection can demonstrate to the EPA that it was impracticable to raise such objection within [the period for public comment] or if the grounds for such objection arose after the period for public comment (but within the time specified for judicial review) and if such objection is of central relevance to the outcome of the rule." Any person seeking to make such a demonstration to us should submit a Petition for Reconsideration to the Office of the Administrator, U.S. EPA, Room 3000, Ariel Rios Building, 1200 Pennsylvania Ave. NW., Washington, DC 20460, with a copy to both the person(s) listed in the preceding **FOR FURTHER INFORMATION CONTACT** section, and the Associate General Counsel for the Air and Radiation Law Office, Office of General Counsel (Mail Code 2344A), U.S. EPA, 1200 Pennsylvania Ave. NW., Washington, DC 20460.

II. Background Information

A. Executive Summary

1. Purpose of the Regulatory Action

This action finalizes amendments that were proposed on December 22, 2008, to address reconsideration issues related to the promulgation of new source performance standards (NSPS) for flares and process heaters on June 24, 2008. This action also lifts the stay that was granted on September 26, 2008 (73 FR 55751) and extended until further notice on December 22, 2008 (73 FR 78552) on the provisions at issue.

2. Summary of Major Provisions

Table 1 presents a summary of major changes to the rule since it was first promulgated on June 24, 2008. The following discussion is a summary of major provisions of this rule.

TABLE 1—SUMMARY OF MAJOR CHANGES SINCE JUNE 24, 2008, PROMULGATION

Affected source	Aspect	NSPS Ja (June 24, 2008)	NSPS Ja final
All Process Heater NO_X limits	Averaging time	24-hour rolling average	30-day rolling average.
Natural Draft Process Heaters	NO_X Emission Limits	40 ppmv	40 ppmv or 0.04 lb/MM BTU.
Forced Draft Process Heaters	NO_X Emission Limits	40 ppmv	60 ppmv or 0.06 lb/MM BTU.
Forced Draft Process Heaters with Co-fired (oil and gas) Burners.	NO_X Emission Limits	40 ppmv	150 ppmv or Weighted average based on oil at 0.40 lb/MM BTU and gas at 0.11 lb/MM BTU.
Natural Draft Process Heaters with Co-fired (oil and gas) Burners.	NO_X Emission Limits	40 ppmv	150 ppmv or weighted average based on oil at 0.35 lb/MM BTU and gas at 0.06 lb/MM BTU.
Process Heaters	Alternate Emission Standards	None	Case by case approval for some circumstances.
Flares	Applicability	New or reconstructed flare systems or existing flare systems that are physically altered to increase flow or to add new connections.	Similar, except specific list of connections that do not trigger applicability.
Fuel gas combustion devices	H_2S concentration limit	162 ppmv H_2S (3-hour average); 60 ppmv H_2S (annual rolling average).	162 ppmv H_2S (3-hour average); No 60 ppmv H_2S long term concentration limit for flares.
Flares	Compliance date for modified flares.	Comply with H_2S limit at start-up, and all other requirements within 1 year.	Comply with H_2S limit at start-up (except for modified flares not previously subject to the H_2S limit in 40 CFR part 60, subpart J or those with monitoring alternatives, or those complying with subpart J as specified in a consent decree, which comply no later than 3 years) and all other requirements within 3 years.
Flares	Flow limits	Flare system-wide flow limit of 250,000 scfd.	No limits.

TABLE 1—SUMMARY OF MAJOR CHANGES SINCE JUNE 24, 2008, PROMULGATION—Continued

Affected source	Aspect	NSPS Ja (June 24, 2008)	NSPS Ja final
Flares	Root Cause Analysis and Corrective Action (RCA/CA).	RCA/CA required on upsets or malfunctions in excess of 500,000 scfd or 500 lbs/day SO_2 from SSM.	RCA/CA required for 500,000 scfd above base load and 500 lbs SO_2 in any 24-hour period.
Flares	Flow monitoring	Continuous	Continuous except for intermittent/emergency only flares with water seal monitoring and limited releases.
Flares	Sulfur Monitoring	Continuous Total Reduced Sulfur (TRS).	Continuous TRS, using reference method 15A (Total Sulfur).

Affected process heaters are those that were modified, reconstructed or constructed after May 14, 2007. For these affected sources, these final amendments include concentration-based nitrogen oxide (NO_X) emissions limits and alternative heating value-based NO_X emissions limits, both determined daily on a 30-day rolling average basis. These final amendments establish limits of 40 parts per million by volume (ppmv) NO_X (or 0.04 pounds per million British thermal units (lb/MMBtu) and 60 ppmv NO_X (or 0.06 lb/MMBtu) for natural draft and forced draft process heaters, respectively. Co-fired process heaters, designed to operate on gaseous and liquid fuel (*e.g.,* oil), must meet either 150 ppmv NO_X or alternative heating value-based limits, weighted based on oil and gas use. The NSPS also contains an alternative compliance option that allows owners and operators to obtain EPA approval for a site-specific NO_X limit for process heaters that may have difficulty meeting the standards under certain situations. These final amendments also include monitoring, recordkeeping and reporting requirements necessary to demonstrate compliance with the NO_X emission standards.

For flares, these final amendments define a flare as a separate affected facility rather than a type of fuel gas combustion device. As such, these final amendments remove requirements for flares to comply with the performance standards for sulfur dioxide (SO_2) (expressed as a 162 ppmv short-term hydrogen sulfide (H_2S) concentration limit) and, instead, establish a separate suite of standards for flares. We are not finalizing the requirement in the December 22, 2008, proposed amendments for flares to meet the long-term 60 ppmv H_2S fuel gas concentration limit. As explained in section IV of this preamble, we determined that requiring refineries to ensure the fuel gas they send to their flares meets a long-term H_2S concentration of 60 ppmv is not appropriate for flares.

Affected flares are those that were modified, reconstructed or constructed after June 24, 2008. In general, a flare is modified if a connection is made into the flare header that can increase emissions from the flare. The NSPS specifically identifies certain connections to a flare that do not constitute a modification of the flare because they do not result in emissions increases.

The final amendments for flares include a suite of standards that apply at all times. This suite of standards requires refineries to: (1) Develop and implement a flare management plan; (2) conduct root cause analyses and take corrective action when waste gas sent to the flare exceeds a flow rate of 500,000 standard cubic feet per day (scfd) above the baseline flow or contains sulfur that, upon combustion, will emit more than 500 pounds (lb) of SO_2 in a 24-hour period; and (3) optimize management of the fuel gas by limiting the short-term concentration of H_2S to 162 ppmv during normal operating conditions.

The final amendments require that flares be equipped with flow and sulfur monitors except in cases where flares are used infrequently or are configured such that they cannot receive high sulfur gas. For flares that are configured such that they only receive inherently low sulfur gas streams, continuous sulfur monitors are not necessary because a root cause analysis will be triggered by an exceedance of the flow rate threshold long before they exceed the 500 lb SO_2 trigger in a 24-hour period.

For infrequently used flares, the NSPS allows for less burdensome monitoring, consisting of monitoring the differential pressure between the flare header and the flare water seal to determine if a gas release to the flare has occurred. Any instance where the pressure upstream of the water seal (expressed in inches of water) exceeds the water seal height triggers a requirement to perform a root cause analysis and corrective action analysis, unless the discharge is related to flare gas recovery system compressor cycling or a planned startup or shutdown (of a refinery process unit or ancillary equipment connected to the flare) following the procedures in the flare management plan. The NSPS also contains an alternative compliance option for refinery flares located in the South Coast Air Quality Management District (SCAQMD) or the Bay Area Air Quality Management District (BAAQMD). An affected flare subject to 40 CFR part 60, subpart Ja may elect to comply with SCAQMD Rule 1118 or both BAAQMD Regulation 12, Rule 11 and BAAQMD Regulation 12, Rule 12 as an alternative to complying with the requirements of subpart Ja.

3. Costs and Benefits

The provisions for flares and other fuel gas combustion devices (*i.e.,* process heaters and boilers) from the final June 2008 standards were stayed. The analysis for this final rule includes the same unit costs for the flare provisions as the final June 2008 rule but reflects recalculated total costs using data collected in the March 2011 information collection request (ICR) to update the number of flares. For the June 2008 standards, we estimated that 40 flares would be affected. We now anticipate that there will be 400 affected flares *that will be subject to this final rule.* Table 2 includes the recalculated cost estimates based on the updated number of flares since 2008, broken out by specific flare requirements. For the other fuel gas combustion devices, the total annualized costs for those provisions were estimated at $24 million (2006 dollars) in the June 2008 rule and remain the same. As discussed below, because there are no additional incremental costs associated with the other fuel gas combustion device provisions, we consider those annual costs accounted for in the final June 2008 standards. We are presenting these

costs and benefits here again, even though we estimate no changes to them, since these provisions will become effective upon this final action to lift the stay on certain provisions in the June 2008 rule. For the June 2008 rule, we estimated the benefits to be $220 million to $1.9 billion and $200 to $1.7 billion at a 3-percent discount rate and 7-percent discount rate, respectively.[1]

Cost impacts for flares are presented in Table 2. The estimated total capital cost of complying with the final amendments to 40 CFR part 60, subpart Ja for flares is $460 million dollars (2006 dollars). The estimated annual cost, including annualized capital costs, is a cost savings of about $79 million (2006 dollars) due to the replacement of some natural gas purchases with recovered flare gas and the retention of intermediate and product streams due to a reduction in the number of malfunctions associated with refinery process units and ancillary equipment connected to the flare. Note that not all refiners will realize a cost savings since we only estimate that refineries with high flare flows will install vapor recovery systems. Although the rule does not specifically require installation of flare gas recovery systems, we project that owners and operators of flares receiving high waste gas flows will conclude, upon installation of monitors, implementation of their flare management plans, and implementation of root causes analyses, that installing flare gas recovery would result in fuel savings by using the recovered flare gas where purchased natural gas is now being used to fire equipment such as boilers and process heaters. The flare management plan requires refiners to conduct a thorough review of the flare system so that flare gas recovery systems are installed and used where these systems are warranted. As part of the development of the flare management plan, refinery owners and operators must provide rationale and supporting evidence regarding the flare waste gas reduction options considered. In addition, consistent with Executive Order 13563 (Improving Regulation and Regulatory Review, issued on January 18, 2011), for facilities implementing flare gas recovery, we are finalizing provisions that would allow the owner or operator to reduce monitoring costs and the number of root cause analyses, corrective actions, and corresponding recordkeeping and reporting they would need to perform. The costs calculated for this rule, however, do not account for potential savings due to these provisions (reduced monitoring, root cause analysis, etc.). We estimate that the final requirements for flares will reduce emissions of SO_2 by 3,200 tons per year (tons/yr), NO_X by 1,100 tons/yr and volatile organic compounds (VOC) by 3,400 tons/yr from the baseline. The overall cost effectiveness is a cost savings of about $10,000 per ton of combined pollutants removed. We also estimate that the final requirements for flares will result in emissions reduction co-benefits of CO_2 equivalents by 1,900,000 metric tonnes per year, predominantly as a result of our estimate of the largest flares employing flare gas recovery, and to a lesser extent, as a result of the flow rate root cause analyses and corrective actions applicable to all flares.

TABLE 2—COST IMPACTS FOR PETROLEUM REFINERY FLARES SUBJECT TO AMENDED STANDARDS UNDER 40 CFR PART 60, SUBPART JA

[Fifth year after the effective date of these final rule amendments]

Subpart Ja requirements	Total capital cost ($1,000)	Total annual cost without credit ($1,000/yr)	Natural gas offset/product recovery credit ($1,000)	Total annual cost ($1,000/yr)	Annual emission reductions (tons SO_2/yr)	Annual emission reductions (tons NO_X/yr)	Annual emission reductions (tons VOC/yr)	Cost effectiveness ($/ton emissions reduced)
Majority of flares (approximately 360 flares)								
Flare Monitoring	72,000	12,000	0	12,000	0	0	0	.....
Flare gas recovery	0	0	0	0	0	0	0	.....
Flare Management	0	790	0	790	0	0	270	2,900
SO_2 RCA/CA	0	1,900	0	1,900	2,600	0	0	760
Flowrate RCA/CA	.....	900	(6,700)	(5,800)	3.4	50	390	(13,000)
Subtotal [1]	72,000	16,000	(6,700)	9,000	2,600	50	660	2,700
Largest flares (approximately 40 flares) [2]								
Flare Monitoring	12,000	2,000	0	2,000	0	0	0	.....
Flare gas recovery	380,000	78,000	(170,000)	(90,000)	380	1,100	2,700	(22,000)
Flare Management	0	88	0	88	0	0	30	2,900
SO_2 RCA/CA	0	220	0	220	290	0	0	760
Flowrate RCA/CA	0	100	(740)	(640)	0.4	6	43	(13,000)
Subtotal [1]	390,000	81,000	(170,000)	(88,000)	660	1,100	2,800	(20,000)
Total [1]	460,000	96,000	(180,000)	(79,000)	3,200	1,100	3,400	(10,000)

[1] All estimates are rounded to two significant figures so numbers may not sum down columns.
[2] The EPA has conducted an alternative analysis that presents the costs and benefits of the rule assuming that no refiners will opt to install flare gas recovery systems as part of their flare management strategy. This analysis is presented in the Regulatory Impact Analysis in the discussion provided in the executive summary and in Section 4.1, available in the docket for this rulemaking.

We estimate the monetized benefits of this final regulatory action for all flares to be $260 million to $580 million (3-percent discount rate) and $240 million to $520 million (7-percent discount rate for health benefits and 3-percent discount rate for climate benefits). For small flares only, we estimate the monetized benefits are $170 million to $410 million (3-percent discount rate) and $150 million to $370 million (7-percent discount rate for health benefits

[1] It is important to note that the EPA has implemented several substantial changes to the benefits methodology since 2008, which makes it challenging to compare the benefits of the June 2008 rule to the benefits of the current rulemaking. The changes with the largest impact on the range of monetized benefits are the removal of the assumption of a threshold in the concentration-response function, the revision of the value-of-a-statistical-life, and the range of risk estimates from epidemiology studies rather than the range of risk estimates supplied by experts. See the regulatory impact analysis for the current rulemaking for more information regarding these changes, which is available in the docket.

and 3-percent discount rate for climate benefits). For large flares only, we estimate the monetized benefits are $93 million to $160 million (3-percent discount rate) and $88 million to $150 million (7-percent discount rate for health benefits and 3-percent discount rate for climate benefits). Several benefits categories, including direct exposure to SO_2 and NO_X benefits, ozone benefits, ecosystem benefits and visibility benefits are not included in these monetized benefits. All estimates are in 2006 dollars for the year 2017.

Although this final rule provides refiners with some additional compliance options and removes some requirements, such as the long-term H_2S limit for flares, the cost savings due this increased flexibility have not been calculated for inclusion in the benefit-cost analysis.

B. Background of the Refinery NSPS

Section 111(b)(1)(A) of the Clean Air Act (CAA) requires the EPA to establish federal standards of performance for new, modified and reconstructed sources for source categories which cause or contribute significantly to air pollution which may reasonably be anticipated to endanger public health or welfare. The standard of performance must reflect the application of the best system of emission reductions (BSER) that (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 (CAA section 111(a)(1)). If it is not feasible to prescribe or enforce a standard of performance, the Administrator may instead promulgate a design, equipment, work practice or operational standard, or a combination of these types of standards (CAA section 111(h)(1)). 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.

The level of control prescribed by CAA section 111 historically has been referred to as ''Best Demonstrated Technology'' or BDT. In order to better reflect that CAA section 111 was amended in 1990 to clarify that ''best systems'' may or may not be ''technology,'' the EPA is now using the term ''best system of emission reduction'' or BSER in its rulemaking packages. See, *e.g.,* 76 FR 52738, 52740 (August 23, 2011); 76 FR 63878, 63879 (October 14, 2011). As was done previously in analyzing BDT, the EPA uses available information and considers the emissions reductions achieved by the different systems available and the costs of achieving those reductions. The EPA also considers the ''other factors'' prescribed by the statute in its BSER analysis. After considering all of this information, the EPA then establishes the appropriate standard representative of BSER. Sources may use whatever system meets the standard.

Section 111(b)(1)(B) of the CAA requires the EPA to periodically review and, as appropriate, revise the standards of performance to reflect improvements in methods for reducing emissions. As a result of our periodic review of the NSPS for petroleum refineries (40 CFR part 60, subpart J), we proposed amendments to the current standards of performance and separate standards of performance for new process units (40 CFR part 60, subpart Ja) (72 FR 27278, May 14, 2007) and we subsequently promulgated those amendments and new standards (73 FR 35838, June 24, 2008). Following promulgation, we received three separate petitions for reconsideration from: (1) 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''); (2) HOVENSA, LLC (''HOVENSA''); and (3) the Environmental Integrity Project, Sierra Club and Natural Resources Defense Council (collectively referred to as ''Environmental Petitioners''). On September 26, 2008, the EPA issued a **Federal Register** notice (73 FR 55751) granting reconsideration of the following issues: (1) The newly promulgated flare modification provision[2]; (2) the ''flare'' definition; (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. The EPA also granted Industry Petitioners' and HOVENSA's request for a 90-day stay for those same provisions under reconsideration. On December 22, 2008, three **Federal Register** notices (73 FR 78260, 73 FR 78546 and 73 FR 78549) were published to extend this stay until a final decision is reached on those issues.

In the September 26, 2008, **Federal Register** notice (73 FR 55751), we also identified other issues for which Petitioners requested reconsideration. We stated that, at that time, we were ''taking no action on all of the other issues raised in the petitions but will consider all of the outstanding issues in a future notice.'' On December 29, 2009, we sent a letter to the Petitioners, through their counsel, stating that ''[t]he Administrator has decided to grant reconsideration of all the remaining issues'' and that ''EPA will address the substantive aspects of the issues under reconsideration through notice and comment actions published in the **Federal Register**.'' A copy of the letter to the Petitioners can be found in the docket for this rulemaking (Docket Item No. EPA–HQ–OAR–2007–0011–0318).

In this action, we are finalizing the amendments for which we granted reconsideration and a stay as outlined in the September 26, 2008, notice and for which we proposed amendments on December 22, 2008. 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 Petitioners for reconsideration in future notices.

We received a total of 22 comments from the following groups on the proposed amendments during the public comment period: (1) Refineries, industry trade associations and consultants; (2) state and local environmental and public health agencies; (3) environmental groups; and (4) other members of the public. These final amendments reflect our full consideration of all of the comments we received. Detailed responses to the comments not included in this preamble, as well as more detailed summaries of the comments addressed in this preamble, are contained in *Standards of Performance for Petroleum Refineries: Background Information for Final Amendments—Summary of Public Comments and Responses,* dated December 2011, which is included in Docket ID No. EPA–HQ–OAR–2007–0011.

In summary, major comments on the proposed process heater requirements were related to the proposed NO_X concentration limits, the alternative heating value limits, consideration of turndown (*i.e.,* when a process heater is operated at less than 50-percent design capacity) and other factors that influence the achievable emissions

[2] The September 26, 2008, **Federal Register** notice (73 FR 55751) described the first issue for which the EPA granted reconsideration as ''the definition of 'modification.''' However, because what we are actually reconsidering is the specific flare modification provision that applies to flares at petroleum refineries rather than the more generally applicable definition of ''modification,'' we have revised the description of this issue as ''the newly promulgated flare modification provision.''

limits. In response, we are raising the limit for new forced draft process heaters from 40 ppmv NO_X at proposal to 60 ppmv NO_X. For both natural draft and forced draft process heaters, we are finalizing alternative heating value limits derived from a more direct numerical conversion of the NO_X concentration limit (*i.e.,* 0.04 lb/MMBtu for natural draft and 0.06 lb/MMBtu for forced draft). For newly constructed, modified and reconstructed natural draft and forced draft process heaters, we are reducing the averaging time for compliance from a 365-day rolling average to a 30-day rolling average applicable during periods of normal operation. We are also finalizing an alternative case-specific compliance option that allows owners and operators to obtain EPA approval for a site-specific NO_X limit in certain conditions such as turndown.

Major comments on the proposed requirements for flares were related to the definition of flare modification for purposes of triggering applicability to this rule, the proposed removal of the flare flow limit, clarification of flare monitoring requirements and clarification of the differences between the requirement for flares and the requirements for other fuel gas combustion devices. We address these comments by clarifying the definition of flare modification and by expanding the list included in the December 22, 2008, proposal, which specifies certain connections that do not constitute a modification of the flare because they do not result in emissions increases. We are finalizing the proposed removal of the flare flow limit and instead, we are promulgating a suite of work practice standards that apply to affected flares. Based on comments received on the December 22, 2008 proposal, we are finalizing definitions of ''fuel gas combustion device'' and ''flare'' to specify that a flare is a separate affected facility rather than a type of fuel gas combustion device. We are also finalizing amendments to clarify certain monitoring requirements and to provide additional monitoring alternatives under certain circumstances.

III. Summary of the Final Rules and Changes Since Proposal

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, boilers and flares), that commence construction, reconstruction or modification after June 11, 1973, but on or before May 14, 2007 (on or before June 24, 2008 for flares). The NSPS were originally promulgated on March 8, 1974, and have been amended several times. In this action, we are promulgating technical clarifications and corrections to subpart J.

New standards of performance 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 facilities at petroleum refineries, including process heaters and other fuel gas combustion devices that commence construction, reconstruction or modification after May 14, 2007. In this action, we are finalizing amendments to subpart Ja to address the issues raised by Petitioners regarding flares and process heaters. We are also finalizing technical corrections to subpart Ja for certain issues that were identified by Industry Petitioners in their August 21, 2008, supplement to their original administrative reconsideration request (Docket Item No. EPA–HQ–OAR–2007–0011–0246).

The following sections summarize the 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 final amendments to the standards of performance for petroleum refineries (40 CFR part 60, subpart J)?

The final amendments 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. 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 are also removing the reference to 40 CFR 60.101a from the description of the applicability dates in 40 CFR 60.100(b) so as not to cause confusion over the definition of ''flare'' in subpart J. We are finalizing a correction to the value and units (in the metric system) for the allowable incremental rate of particulate matter (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. Finally, we are finalizing a definition of ''fuel gas'' that incorporates the same clarifications regarding vapors from wastewater treatment units and marine tank vessel loading operations identified in the subpart Ja definition of ''fuel gas'' (described later in this preamble).

B. What are the final amendments to the standards of performance for process heaters (40 CFR part 60, subpart Ja)?

We proposed several amendments to the standards of performance for process heaters, including adding emission limits in units of lb/MMBtu, extending the emission limit averaging time from 24 hours to 365 days, raising the emission limit for modified and reconstructed forced draft process heaters and raising the emission limit for co-fired process heaters. After consideration of all of the public comments and our own additional analyses, we are finalizing the process heater requirements, as described in this section.

Table 3 presents a comparison of the proposed and final 40 CFR part 60, subpart Ja amendments for process heaters. The final amendments include four subcategories of process heaters: (1) Natural draft process heaters; (2) forced draft process heaters; (3) co-fired natural draft process heaters; and (4) co-fired forced draft process heaters. At proposal, all co-fired process heaters were included in one subcategory, for a total of three process heater subcategories, but, based on emissions data from co-fired process heaters, we divided natural draft and forced draft co-fired process heaters into separate subcategories with different emissions limits.

For each of the first two subcategories, the final amendments include a concentration-based NO_X emissions limit and a heating value-based NO_X emissions limit, both determined daily on a 30-day rolling average basis. For the natural draft process heater subcategory, the concentration-based NO_X emissions limit for newly constructed, modified and reconstructed natural draft process heaters is 40 ppmv (dry basis, corrected to 0-percent excess air) determined daily on a 30-day rolling average basis. The heating value-based NO_X emissions limit for newly constructed, modified and reconstructed natural draft process heaters is 0.040 lb/MMBtu higher heating value basis determined daily on a 30-day rolling average basis. The averaging time for both of these limits is shorter than the 365-day averaging time that was proposed, and the heating value-based NO_X emissions limit differs from the proposed limit in that it is a more direct numerical conversion from 40 ppmv NO_X. At proposal, we provided a longer averaging time so that short periods of turndown (*i.e.,* when a process heater is operating at less than 50-percent design

capacity) would not significantly affect the overall performance of the unit. Our analysis of the additional data that we obtained following the proposal supported revising all NO_X emissions limits to be on a 30-day rolling average basis, which is achievable for process heaters during periods of normal operation. These data indicate that process heaters equipped with ultra low NO_X burners meet the emission limits described above if compliance is determined on a 30-day rolling average basis. We are finalizing alternative compliance options that allow the owners and operator to establish site-specific limits applicable during certain conditions such as turndown. Section IV.A of this preamble provides additional information regarding the rationale and analyses leading to these final amendments.

For the second subcategory, forced draft process heaters, the concentration-based NO_X emissions limit for newly constructed, modified and reconstructed forced draft process heaters is 60 ppmv (dry basis, corrected to 0-percent excess air) determined daily on a 30-day rolling average basis. The heating value-based NO_X emissions limit for newly constructed, modified and reconstructed forced draft process heaters is 0.060 lb/MMBtu higher heating value basis determined daily on a 30-day rolling average basis. The higher limit for new forced draft process heaters (at proposal, the limit was 40 ppmv) is based on additional data and a re-evaluation of BSER, as described later in this preamble. As with natural draft process heaters, the averaging time for both of these limits is shorter than proposed, and the final heating value-based NO_X emissions limit is a more direct numerical conversion from 60 ppmv NO_X. Section IV.A of this preamble provides additional information regarding the rationale and analyses leading to these final amendments.

For each of these subcategories, a process heater need only meet either the concentration-based NO_X emissions limit or the heating value-based NO_X emissions limit. The refinery owner or operator may choose to comply with either limit at any time, provided that they are monitoring the appropriate variables to assess the heating value-based NO_X emissions limit. If the refinery owner or operator does not choose to monitor fuel composition, then they must comply with the concentration-based NO_X emissions limit.

TABLE 3—PROPOSED AND FINAL AMENDMENTS FOR PROCESS HEATERS

	Proposal (December 22, 2008)	Final
Averaging time	365-day rolling average	30-day rolling average.
Natural Draft NO_X Emission Limits	40 ppmv or 0.035 lb/MM BTU	40 ppmv or 0.04 lb/MM BTU.
Forced Draft NO_X Emission Limits	*New:* 40 ppmv or 0.035 lb/MM BTU *M/R:* 60 ppmv or 0.055 lb/MM BTU	60 ppmv or 0.06 lb/MM BTU.
Co-fired Burner (oil and gas) NO_X Emission Limits.	150 ppmv or Weighted average based on oil at 0.27 lb/MM BTU and gas at 0.08 lb/MM BTU.	150 ppmv or Weighted average based on oil at 0.40 lb/MM BTU and gas at 0.11 lb/MM BTU forced draft and weighted average based on oil at 0.35 lb/MM BTU and gas at 0.06 lb/MM BTU for natural draft.

As proposed, initial compliance with the heating value-based emissions limits will be demonstrated by conducting a performance evaluation of the continuous emission monitoring system (CEMS) in accordance with Performance Specification 2 in appendix B to 40 CFR part 60, with EPA Method 7 of 40 CFR part 60, appendix A–4 as the Reference Method, along with fuel flow measurements and fuel gas compositional analysis. The NO_X emission rate is calculated using the oxygen (O_2)-based F factor, dry basis according to EPA Method 19 of 40 CFR part 60, appendix A–7. Ongoing compliance with this NO_X emissions limit is determined using a NO_X CEMS and at least daily sampling of fuel gas heat content or composition to calculate a daily average heating value-based emissions rate, which is subsequently used to determine the 30-day average.

The third and fourth subcategories of process heaters are co-fired process heaters. A co-fired process heater is a process heater that employs burners that are designed to be supplied by both gaseous and liquid fuels. As described in more detail in section IV.A of this preamble, co-fired process heaters do not include gas-fired process heaters that have emergency oil back-up burners. There are two compliance options for each subcategory of co-fired process heaters: (1) 150 ppmv (dry basis, corrected to 0-percent excess air) determined daily on a 30 successive operating day rolling average basis; and (2) a source-specific daily average emissions limit. Unlike gas-fired process heaters, the owner or operator of a co-fired process heater must choose one emissions limit and show compliance with that limit. For co-fired natural draft process heaters, the daily average emissions limit is based on a limit of 0.06 lb/MMBtu for the gas portion of the firing and 0.35 lb/MMBtu for the oil portion of the firing. For co-fired forced draft process heaters, the daily average emissions limit is based on a limit of 0.11 lb/MMBtu for the gas portion of the firing and 0.40 lb/MMBtu for the oil portion of the firing. These limits are different than proposed, based on a re-evaluation of BSER with new data received during the public comment period. All of the requirements for emissions monitoring, recordkeeping and reporting for co-fired process heaters are the same as for the other process heater subcategories.

We are also finalizing an alternative compliance option that allows owners and operators to obtain EPA approval for a site-specific NO_X limit for certain process heaters. This compliance option was provided in the proposed amendments, but it was limited to (1) natural draft and forced draft modified or reconstructed process heaters that lack sufficient space to accommodate combustion modification-based technology and (2) natural draft and forced draft co-fired process heaters. In the final amendments, we are finalizing this compliance option for those process heaters mentioned above while also providing this compliance option for the following additional types of process heaters: (3) modified or reconstructed induced draft process heaters that have downwardly firing burners and (4) forced draft and natural draft process heaters that operate at low firing rates, or turndown, for an extended period of time. As we noted in the preamble to the proposed amendments, in limited cases, existing natural draft or forced draft process heaters have limited firebox size or other constraints such

that they cannot apply the BSER of ultra-low NO_X burners or otherwise meet the applicable limit and some co-fired units may not be able to achieve the NO_X limitations even with ultra-low NO_X burner control technology. In addition, commenters noted that downwardly fired process heaters with induced draft fans have similar NO_X control issues as forced draft heaters, but the definition of forced draft heater does not include these induced draft heaters (these are defined as natural draft process heaters). Therefore, we added a provision to allow induced draft process heaters with downwardly-firing burners to use the alternative compliance option.

Finally, we note that the emissions limits for forced draft and natural draft gas-fired process heaters are based on the performance of ultra-low NO_X burner control technologies. The ultra-low NO_X burner technology suppliers recommend operating with higher excess air rates at low firing rates (at or below approximately one-half of the maximum firing capacity), which causes higher NO_X concentrations at low firing rates. Therefore, all types of process heaters with ultra-low NO_X burner control technologies may be unable to meet the emissions limits if they are operated at low firing rates for an extended period of time. Requesting a site-specific emissions limit requires a detailed demonstration that the application of the ultra-low NO_X burner technology is not feasible or that the technology cannot meet the NO_X emissions limits given the conditions of the process heater (downward fired induced draft, co-fired or prolonged turndown); the refinery must also conduct source tests in developing a site-specific emissions limit for its process heater. This analysis must be submitted to and approved by the Administrator.

We are finalizing the proposed clarification that owners and operators of process heaters in any subcategory with a rated heating capacity of less than 100 million British thermal units per hour (MMBtu/hr) have the option of using CEMS. The final rule states that owners and operators of process heaters subject to 40 CFR part 60, subpart Ja should use CEMS to demonstrate compliance unless the heater is 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 MMBtu/hr; owners and operators of those specific process heaters have the alternative option of biennial source testing to determine compliance. As requested by commenters, we have provided additional detail in the final rule regarding how to develop the O_2 operating limit, including provisions on how to develop an O_2 operating curve to ensure compliance with the NO_X emission limit at different process heater firing rates. We are requiring that owners and operators with process heaters in any subcategory that are complying using biennial source testing establish a maximum excess O_2 concentration operating limit or operating curve that can be met at all times, even during turndown, and comply with the O_2 monitoring requirements for ongoing compliance demonstration.

C. What are the final amendments to the standards of performance for flares (40 CFR part 60, subpart Ja)?

We proposed several amendments to the standards of performance for flares, including, but not limited to, amending the flare modification provision, removing the numerical limit on the flow rate to the flare, revising the flare management plan requirements to include a list of connections to the flare and an identification of baseline conditions, clarifying when a root cause analysis is required, revising the sulfur and flow monitoring requirements and providing additional time for compliance. After consideration of all of the public comments, and our own additional analyses, we are finalizing the flare requirements, as described in this section.

We did not propose to revise the definitions of "fuel gas combustion device" and "flare" on December 22, 2008. However, based on public comment and changes to the flare requirements, as described later in this section, we have decided to finalize revisions to these definitions to specify that, for purposes of 40 CFR part 60, subpart Ja, a flare is a separate affected facility rather than a type of fuel gas combustion device. This change makes clearer the differences between the requirements for flares and the requirements for fuel gas combustion devices, particularly in terms of sulfur and flow rate monitoring requirements and thresholds for root cause analyses and corrective action analyses. We are also making corrections, as needed, in numerous paragraphs throughout subpart Ja for consistency with the amended definitions (*e.g.*, adding "and flares," where applicable, to paragraphs with requirements for "fuel gas combustion devices").

We are finalizing the flare modification provision in 40 CFR 60.100a(c), as described below, to specify certain connections to a flare that do not constitute a modification of the flare because they do not result in emissions increases. On December 22, 2008, we proposed that the following types of connections to a flare would not be considered a modification of the flare: (1) Connections made to install monitoring systems to the flares; (2) connections made to install a flare gas recovery system; (3) 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; and (4) 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. We are finalizing those proposed amendments and also adding the following types of connections to the list of connections to flares that are not modifications of flares: (1) Connections between flares; (2) connections for flare gas sulfur removal; and (3) connections made to install redundant flare equipment (such as a back-up compressor). We are also clarifying one of the proposed exemptions to indicate that connections made to upgrade or enhance components of flare gas recovery systems (*e.g.*, additional compressors or recycle lines) are not modifications.

We are not finalizing the proposed amendment to provide additional time for flares that need to install additional amine scrubbing and amine stripping columns to meet the requirement to limit the long-term concentration of H_2S to 60 ppmv (determined daily on a 365 successive calendar day rolling average basis) (hereafter referred to as the long-term 60 ppmv H_2S fuel gas concentration limit). Instead, based on comments received during the public comment period for the proposed amendments and our own additional analyses, we are removing the requirement for flares to meet the long-term 60 ppmv H_2S fuel gas concentration limit. As explained in section IV, we determined that requiring refineries to ensure the fuel gas they send to their flares meets a long-term H_2S concentration of 60 ppmv is not appropriate for flares.

We are promulgating final amendments for flares that include a suite of standards that apply at all times that are aimed at reducing SO_2 emissions from flares. These amendments include several provisions that were proposed on December 22,

2008, as well as others that differ from those proposed, but are a logical outgrowth of the proposed amendments. This suite of standards requires refineries to: (1) Develop and implement a flare management plan; (2) conduct root cause analyses and take corrective action when waste gas sent to the flare exceeds a flow rate of 500,000 standard cubic feet (scf) above the baseline flow to a flare in any 24-hour period (rather than the proposed threshold of 500,000 scf in any 24-hour period without considering the baseline); (3) conduct root cause analyses and take corrective action when the emissions from the flare exceed 500 lb of SO_2 in a 24-hour period (instead of 500 lb SO_2 above the emissions limit); and (4) optimize management of the fuel gas by limiting the short-term concentration of H_2S to 162 ppmv during normal operating conditions (determined hourly on a 3-hour rolling average basis). As explained further in preamble section IV.B, 40 CFR part 60, subpart J sets a performance standard for SO_2 (expressed as a 162 ppmv short-term H_2S concentration limit) in fuel gas entering fuel gas combustion devices. However, for this final rule, we have determined that flares should be treated separately from other fuel gas combustion devices because they meet the criteria set forth in CAA section 111(h)(2)(A) since emissions from a flare do not occur ''through a conveyance designed and constructed to emit or capture such pollutant.'' The flare itself is not a ''conveyance'' that is ''emitting'' or ''capturing'' these pollutants. Instead, pollutants such as SO_2 are created in the flame that burns outside the flare tip. Therefore, we have determined that this suite of work practice standards, which includes optimization of fuel gas management (based on limiting concentration of H_2S to 160 ppmv) is more appropriate for flares, as opposed to the H_2S performance standard in subpart J, applicable to fuel gas systems. See section IV.B of this preamble for a more detailed explanation of these requirements. In this rule, we are using the term ''normal operating conditions'' to describe situations where the process is operating in a routine, predictable manner, such that the gases from the process are predictable, as opposed to less-predictable swings related to emergency situations during which the flare begins to operate as a safety device. All of these requirements will apply during the vast majority of the time. Under a very narrow and limited set of circumstances, such as when a flare is used as a safety device under emergency conditions,[3] the flare will be subject to all of these requirements except for the requirement to optimize management of the fuel gas.

In addition, we are specifying that, if a discharge exceeding either or both of the SO_2 or flow thresholds described above is the result of a planned startup or shutdown of a refinery process unit or ancillary equipment connected to the flare, and the flare management plan procedures for minimizing flow (which minimizes emissions) during that type of event are followed, a root cause analysis and corrective action analysis are not required. Finally, we are finalizing the proposed added provisions to ensure that owners and operators implement corrective actions on the findings of the SO_2 or flow rate root cause analyses and to specify a deadline for performing the corrective actions.

We are finalizing the proposed amendment to remove the 250,000 scfd 30-day average flow rate limit. Our rationale for this decision is explained in the preamble to the proposed amendments (73 FR 78530) and also in section IV of this preamble.

We are finalizing one proposed amendment to the flare management plan and adding several new requirements as a logical outgrowth of the proposed amendments, considering the public comments we received, to ensure compliance with the flare standards. First, as proposed, we are requiring a list of refinery process units and fuel gas systems connected to each affected flare. However, we are also adding a requirement for a simple process flow diagram showing the design of the flare, connections to the flare header and subheader system(s), and all gas lines associated with the flare. With these two requirements, we are clarifying that the flare management plan must include a diagram of the flare and connections, but the diagram need not be a detailed piping and instrumentation diagram that shows all process units and ancillary equipment connected to the flare. We are also requiring the owner and operator of an affected flare to assess and minimize flow to affected flares from these process units and fuel gas systems. Second, we are adding new requirements that the flare management plan include design and operation details about the affected flare, including tip diameter, type of flare, monitoring methods and a description of the flare gas recovery system, if present. The inclusion of these details will ensure that the rest of the flare management plan is reasonable and appropriate for that affected flare.

Third, as a logical outgrowth of the proposed amendments, considering the public comments we received, we are adding a new requirement for owners and operators to determine the baseline flow to each flare, including purge and sweep gas, and include this baseline flow in the flare management plan. As described later in this preamble, developing the baseline is important because the final threshold for the flare flow root cause analysis takes this baseline flow into consideration. Finally, we are adding a new requirement to minimize the volume of gas flared during maintenance of a flare gas recovery system.

We have decided to remove the requirement for the owner or operator to explain in the flare management plan how a root cause analysis and corrective action analysis will be conducted if the flow to the flare exceeds the specified threshold. Instead, all the requirements for determining when and how to conduct a root cause analysis and corrective action analysis, and the requirements for when and how to implement a corrective action, have been expanded, as described later in this section, and moved to 40 CFR 60.103a(c) through (e).

We are specifying that, for modified flares, the flare management plan must be developed and implemented by no later than November 11, 2015 or upon startup of the modified flare, whichever is later (the proposed amendments provided 18 months with an additional 6 months if the owner or operator committed to installing a flare gas recovery system). In addition, because of the lack of a direct flow limit and the addition of the baseline flow value, we are adding a requirement that the flare management plan must be submitted to the Administrator.

As with the flare management plan, the owner or operator of an affected flare must comply with the root cause analysis and corrective action analysis requirements within 3 years from the effective date of this final rule or upon startup of the modified flare, whichever is later.

We are finalizing several proposed amendments to the sulfur monitoring requirements and revising other requirements as a logical outgrowth of the proposed amendments, considering the public comments we received. We consolidated the proposed alternatives to monitor reduced sulfur compounds and total sulfur compounds into a

[3] *Background Information for New Source Performance Standards,* Vol. 3, Promulgated Standards (APTD–1352c; Publication No. EPA 450/2–74–003), pg 127 (February 1974) (*NSPS BID Vol. 3*).

provision that allows the use of total reduced sulfur monitoring. We also clarified the span requirements for these monitors and are allowing the use of cylinder gas audits for relative accuracy assessments. We are finalizing the H_2S monitoring alternative method for determining total sulfur content in the flare gas, as proposed, but we have clarified the span requirements for this monitor and are allowing the use of cylinder gas audits for relative accuracy assessments, similar to the total reduced sulfur monitor requirements. For refineries that measure SO_2 concentrations in the exhaust from a fuel gas combustion device that combusts gas representative of the gas discharged to the flare, we added an alternative to allow the owner or operator to use the existing SO_2 CEMS data to calculate the total sulfur content in the flare gas.

We received public comments stating that the flow and sulfur monitoring requirements for flares were too burdensome for flares that are used infrequently or that are configured such that they cannot receive high sulfur flare gas. Based on our evaluation of these comments, we are providing new alternatives to continuous flow and sulfur monitoring for certain flares. First, for flares that are configured such that they only receive inherently low sulfur gas streams described in 40 CFR 60.107a(a)(3)(i) through (iv) or (b), continuous sulfur monitors are not necessary because a root cause analysis will be triggered by an exceedance of the flow rate threshold long before they exceed the 500 lb SO_2 trigger in a 24-hour period.

Second, we are providing an alternative monitoring option for emergency flares, secondary flares and flares equipped with a flare gas recovery system designed, sized and operated to capture all flows (except flows resulting from planned startup and shutdown that are addressed in the flare management plan). If this option is applicable, the owner or operator may elect to continuously monitor the water seal height and the pressure in the flare header just upstream of the water seal rather than install total sulfur and flow monitoring systems. If this monitoring option is selected, any instance where the pressure upstream of the water seal (expressed in inches of water) exceeds the water seal height triggers a requirement to perform a root cause analysis and corrective action analysis, unless the discharge is related to flare gas recovery system compressor cycling or a planned startup or shutdown (of a refinery process unit or ancillary equipment connected to the flare) following the procedures in the flare management plan. An ''emergency flare'' is a flare that combusts gas exclusively released as a result of malfunctions (and not startup, shutdown, routine operations or any other cause) and is characterized as having four or fewer discharge events in any 365 consecutive calendar days.

Owners or operators of affected flares that have flare gas recovery systems with staged compressors that elect to use this monitoring option must identify these flares in their flare management plan, identify the time period required for the staged compressors to actively start to recover gas and identify the operating parameters monitored and procedures employed to minimize the duration of flaring during compressor staging. If a pressure exceedance is caused during compressor staging and the duration of the pressure exceedance is less than the time specified in the flare management plan, then a root cause analysis is not required and the pressure exceedance is not required to be reported. If a pressure exceedance is not attributable to compressor staging (*i.e.,* all staged compressors are active), if a pressure exceedance is the result of a planned startup and shutdown event during which the flare management plan is not followed or if the duration of a pressure exceedance attributable to compressor staging is greater than the time specified in the flare management plan, then a root cause analysis and corrective action analysis are required and the pressure exceedance must be reported. More than four pressure exceedances required to be reported, as described above and under 40 CFR 60.108a(d)(5) (hereafter referred to as ''reportable pressure exceedances'') in any 365 consecutive calendar days is an indication that the flare gas recovery system is not adequately sized, and the sulfur and flow monitors, as required in 40 CFR 60.107a(e) and (f), must be installed if that occurs.

Third, we are clarifying that monitors for flow and sulfur on the second flare in a staged flare configuration are not required where the water seal monitoring requirements adequately and appropriately address this scenario. Under most circumstances, the root cause analysis is expected to be triggered, based on the flow to or emissions from the primary flare. However, in cases where the capacity of the primary flare is small (less than 500,000 scfd), this may not always be the case. Additionally, we consider the water seal monitoring on the secondary flare to be appropriate to ensure that gases are not released to the secondary flare inadvertently. We clarify in this final rule that if a root cause analysis is triggered for the primary flare, releases to the secondary flare do not trigger an additional root cause analysis (*i.e.,* the releases may be treated as one event). However, if flow is diverted to the secondary flare, then a root cause analysis is required, even if a root cause analysis was not triggered for the primary flare, based on flow rate or SO_2 emissions. In addition, if flow is diverted to the secondary flare five or more times in a 365-day period, flow monitoring of the secondary flare is required. We anticipate that the upstream sulfur monitor on the primary flare can be used to determine the sulfur content of the gas diverted to the secondary flare.

In response to comments, we are also finalizing a new amendment providing an alternative compliance option in 40 CFR 60.103a(g) and 40 CFR 60.107a(h) for certain flares. Specifically, for refineries located in the SCAQMD, an affected flare subject to 40 CFR part 60, subpart Ja may elect to comply with SCAQMD Rule 1118 as an alternative to complying with the requirements for flares in 40 CFR 60.103a(a) through (e) and the associated monitoring provisions in 40 CFR 60.107a(e) and (f). Similarly, for refineries located in the BAAQMD, an affected flare subject to subpart Ja may elect to comply with both BAAQMD Regulation 12, Rule 11 and BAAQMD Regulation 12, Rule 12 as an alternative to complying with the requirements for flares in 40 CFR 60.103a(a) through (e) and the associated monitoring provisions in 40 CFR 60.107a(e) and (f). We are also finalizing specific provisions within the standards for owners or operators (and manufacturers of equipment) to submit a request for a determination of equivalence for ''an alternative means of emission limitation'' that will achieve a reduction in emissions at least equivalent to the reduction in emissions achieved under any of the final subpart Ja design, equipment, work practice or operational requirements in accordance with CAA section 111(h).

For fuel gas combustion devices and sulfur recovery plants, we are correcting and clarifying the threshold for a root cause analysis and corrective action analysis. The proposed root cause analysis threshold for both types of process units was 500 lb SO_2 above the emission limit, but the proposed amendments directed the owner or operator to compare the SO_2 emissions to ''the period of the exceedance'' for fuel gas combustion devices and ''the entire 24-hour period'' for sulfur recovery plants. That language meant that if one 12-hour average for a sulfur

recovery plant was above the emission limit, the owner or operator would have compared those emissions to the emissions allowed over an entire 24 hours to determine if root cause analysis was required. However, although a 12-hour average above the emission limit clearly means that more SO_2 was emitted than allowed by that emissions limit, it is possible that, since the time periods being compared were not analogous, the ''allowed emissions'' over 24 hours could be more than the actual emissions that made up the one 12-hour average. Upon further consideration, we see no reason for the requirements to be different for fuel gas combustion devices and sulfur recovery plants. Therefore, we are finalizing an amendment that states that the threshold for a root cause analysis and corrective action analysis for both sulfur recovery plants and fuel gas combustion devices is 500 lb above the emission limit during one or more consecutive periods of excess emissions [4] or any 24-hour period, whichever is shorter. This clarifying amendment is needed to ensure that the magnitude of the emissions limit exceedance is properly compared to what would have been emitted if the emissions were equivalent to the emissions limit based on the averaging time allowed for that emissions limit.

Finally, we are finalizing the amendments at 40 CFR 60.108a(c) and (d) mostly as proposed to clarify recordkeeping and reporting when a root cause analysis and corrective action analysis are required. These clarifications were needed to more clearly delineate the differences in the recordkeeping and reporting requirements for flares, fuel gas combustion devices and sulfur recovery plants. The differences between the proposed amendments and the final amendments are corrections to be consistent with changes to the root cause analysis and corrective action analysis requirements already described. We are also finalizing 40 CFR 60.108a(c), as proposed, to add recordkeeping requirements for the proposed monitoring option that is based on periodic manual sampling and analysis to determine the total sulfur-to-H_2S ratio.

[4] As noted above, the proposed amendments used the term ''period of the exceedance'' for fuel gas combustion devices. That term was intended to have the same meaning as a period of excess emissions (or multiple consecutive periods of excess emissions), as defined in 40 CFR 60.106a(b) or 40 CFR 60.107a(i)). Therefore, the final amendments refer to ''one or more consecutive periods of excess emissions'' rather than ''period of the exceedance.''

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

We proposed amendments to a number of definitions in 40 CFR 60.101a. This section describes whether we are finalizing the amendments as proposed, finalizing an amendment different than (but as a logical outgrowth of) what was proposed or not finalizing the proposed amendment.

We are finalizing amendments to the definitions of ''flexicoking unit'' and ''fluid coking unit,'' as proposed.

We are finalizing a definition of ''delayed coking unit'' that is different than the proposed amendments to clarify what pieces are included in a delayed coking unit. The final June 2008 rule did not explicitly describe the pieces of a delayed coking unit. We proposed to amend the definition in December 2008 to specify that a delayed coking unit ''consists of the coke drums and associated fractionator.'' In the course of evaluating public comments on the proposed definition, we looked more closely at the operation of delayed coking units and determined that the fractionators, quench water system and coke cutting equipment are integral to the operation of a delayed coking unit. Therefore, we are revising the definition of ''delayed coking unit'' in these final amendments to include ''the coke drums associated with a single fractionator and the associated fractionator; the coke drum cutting water and quench system, including the jet pump and coker quench water tank; process piping and associated equipment such as pumps, valves and connectors; and the coke drum blowdown recovery compressor system.'' Finally, to avoid any potential retroactive compliance issues that could arise for certain delayed coking units because of the changes to the definition of ''delayed coking unit'' between the proposal and the final rule, we are moving the date for determining applicability of NSPS subpart Ja for those newly constructed, reconstructed and modified delayed coking units specifically affected by this change from the date of the proposal to the promulgation date of these final amendments. See CAA section 111(a)(2).

We are finalizing definitions of ''forced draft process heater,'' ''natural draft process heater'' and ''co-fired process heater,'' which will enable owners and operators to determine the appropriate subcategory for each of their process heaters. Based on public comments, the final amendments have been revised slightly from the proposed definitions to clarify that induced draft systems are defined as natural draft process heaters and balanced draft systems are defined as forced draft process heaters. We are also revising the definition of ''co-fired process heater'' to clarify that this type of process heater does not include gas burners that have emergency oil back-up burners. We are finalizing the definition of ''air preheat,'' as proposed, except that we are substituting the term ''sensible'' for ''latent'' to describe the heat recovered from exhaust gases.

We are finalizing the definitions of ''flare gas recovery system'' and ''process upset gas,'' as proposed, and we are adding a new definition of ''flare gas header system.'' We are finalizing a revision to the definition of ''flare'' to refer to the ''flare gas header system'' rather than repeat the components of the flare gas header system within the definition of flare. In addition, we are clarifying in the definition of ''flare'' that, in the case of an interconnected flare gas header system (*i.e.,* two or more flare tips share the same flare gas header system or are otherwise connected such that they receive flare gas from the same source), the ''flare'' includes each combustion device serviced by the interconnected flare gas header system and the interconnected flare gas header system.

We are finalizing definitions of ''corrective action,'' ''corrective action analysis'' and ''root cause analysis'' with minor changes from proposal to update section references and to expand upon the types of factors that should be taken into consideration for root cause and corrective action analyses. We are adding definitions of ''purge gas'' and ''sweep gas'' to clarify the requirements of the flare minimization plan. We are also adding new definitions of ''emergency flare,'' ''cascaded flare system,'' ''non-emergency flare,'' ''primary flare'' and ''secondary flare'' to clarify the types of flares that are and are not allowed to use the water seal monitoring alternative for flares.

We are finalizing the amendments to the definition of ''petroleum refinery,'' as proposed. As we noted in the preamble to the proposed amendments, 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. Facilities that produce oil shale or tar sands-derived crude oil and then upgrade these materials and produce refined products would be petroleum refineries. Additionally, facilities that produce oil shale or tar sands-derived

crude oil using any cracking process would be considered petroleum refineries.

We are not finalizing the proposed amendments to "refinery process unit" to avoid possible conflicts and confusion caused by having different definitions for "refinery process unit" in 40 CFR part 60, subparts J and Ja, but we are adding a new definition of "ancillary equipment" and using this term to clarify that the flare modification provisions and standards apply to the types of units listed in the proposed definition of "refinery process unit." Specifically, we are defining *ancillary equipment* as equipment used in conjunction with or that serve a refinery process unit. *Ancillary equipment* includes, but is not limited to, storage tanks, product loading operations, wastewater treatment systems, steam- or electricity-producing units (including coke gasification units), pressure relief valves, pumps, sampling vents and continuous analyzer vents.

We are amending the definition of "fuel gas," as proposed, to clarify that process units that gasify petroleum coke at a petroleum refinery are producing refinery fuel gases. We also proposed to amend the definition to state that gas generated by process units that calcine petroleum coke into anode grade coke is not fuel gas. Based on public comment, we are amending the definition to state that gas generated by coke calciners producing all premium grade coke (rather than just anode grade coke, as proposed) is not fuel gas. Also upon consideration of public comments, we are amending the definition of "fuel gas" to clarify which vapor streams we intended to exclude. The proposed definition indicated that vapors collected and combusted to comply with specific standards were not considered fuel gas. The final amended definition clarifies that vapors that are collected and combusted in a thermal oxidizer or flare installed to control emissions from wastewater treatment units other than those processing sour water, marine tank vessel loading operations and asphalt processing units are not considered fuel gas, regardless of whether the action is required by another standard.

Finally, we are finalizing several proposed amendments to the definition of "sulfur recovery plant" to clarify the intent of the definition. We are correcting the spelling of "H_2S." We are also clarifying that multiple units recovering sulfur from a common source of sour gas produced at a refinery are considered one sulfur recovery plant. In addition, we are clarifying that loading facilities downstream of the sulfur pits are not part of the sulfur recovery plant (the proposed definition only specified secondary sulfur storage vessels).

E. What are the final technical corrections to 40 CFR part 60, subpart Ja?

See Table 4 of this preamble for miscellaneous technical corrections that we are finalizing throughout 40 CFR part 60, subpart Ja. As mentioned previously, some of these technical corrections are in response to straightforward issues raised by Industry Petitioners in their August 21, 2008, supplement to their original petition for reconsideration (Docket Item No. EPA–HQ–OAR–2007–0011–0246). Other technical corrections are needed to correct typographical errors and to correct equation and paragraph designations.

TABLE 4—TECHNICAL CORRECTIONS TO 40 CFR PART 60, SUBPART JA

Section	Technical correction and reason
60.102a(f)(1)(ii)	Replace "300 ppm by volume of reduced sulfur compounds and 10 ppm by volume of hydrogen sulfide (HS_2), each calculated as ppm SO_2 by volume (dry basis) at zero percent excess air" with "300 ppmv of reduced sulfur compounds and 10 ppmv of H_2S, each calculated as ppmv SO_2 (dry basis) at 0-percent excess air" for consistency of units and to correct a typographical error.
60.104a(d)(4)(ii)	Redesignate Equation 3 as Equation 5 to provide for the addition of new Equations 3 and 4.
60.104a(d)(4)(iii)	Redesignate Equation 4 as Equation 6 to provide for the addition of new Equations 3 and 4.
60.104a(d)(4)(v)	Redesignate Equation 5 as Equation 7 to provide for the addition of new Equations 3 and 4.
60.104a(d)(8)	Redesignate Equation 6 as Equation 8 to provide for the addition of new Equations 3 and 4.
60.104a(f)(3)	Redesignate Equation 7 as Equation 9 to provide for the addition of new Equations 3 and 4. Replace "hourly" with "3-hour" in the definition of the new Equation 9 variable "Opacity limit" and replace "source test runs" with "source test" in the definition of the new Equation 9 variable "$Opacity_{st}$" to clarify the information required for new Equation 9.
60.104a(h)(5)(iv)	Redesignate the reference to Equation 6 as a reference to Equation 8 to provide for the addition of new Equations 3 and 4.
60.105a(b)	Replace "in § 60.102a(b)(1) shall comply with the requirements in paragraphs (b)(1) through (3) of this section" with "in § 60.102a(b)(1) that uses a control device other than fabric filter or cyclone shall comply with the requirements in paragraphs (b)(1) and (2) of this section" to clarify applicability of the requirements and remove the reference to a nonexistent paragraph.
60.105a(b)(1)	Replace "according to the requirements in paragraph (b)(1)(i) through (iii) of this section" with "according to the applicable requirements in paragraphs (b)(1)(i) through (v) of this section" to clarify and correct paragraph reference.
60.105a(b)(1)(ii)(A)	Replace "alterative" with "alternative" to correct the use of an incorrect word.
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(a)(2)(i)	Replace "320 ppmv H_2S" with "300 ppmv H_2S" to make the span value for a H_2S monitor consistent with the span value in 40 CFR part 60, subpart J.
60.108a(d)(5)	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.

IV. Summary of Significant Comments and Responses

As previously noted, we received a total of 22 comments addressing the proposed amendments. These comments were received from refineries, industry trade associations, consultants, state and local environmental and public health agencies, environmental groups and members of the public. Brief summaries of the major comments and our complete responses to those comments are included in the following sections. A summary of the remainder of the

comments received during the comment period and responses thereto, as well as more detailed summaries of the comments addressed in this preamble, can be found in *Standards of Performance for Petroleum Refineries: Background Information for Final Amendments—Summary of Public Comments and Responses,* which is included in the docket for the final amendments (Docket ID No. EPA–OAR–HQ–2007–0011). The docket also contains further details on all the analyses summarized in the responses below.

In responding to the public comments, we re-evaluated the cost and emission reduction impact estimates of some of the control options and re-evaluated the related BSER determinations. In our BSER determinations, we took all relevant factors into account consistent with other agency decisions.

A. Process Heaters

Comment: Commenters stated that new forced draft process heaters cannot meet the proposed emissions limit of 40 ppmv NO_X, so the EPA should revise the emissions limits for new forced draft process heaters to be the same as the limit for modified and reconstructed forced draft process heaters (60 ppmv NO_X). One commenter referenced a general technical document written by a process heater burner manufacturer regarding a new forced draft process heater at their refinery to support the assertion that new process heaters cannot meet the proposed limit without selective catalytic reduction or other add-on controls. Another commenter also requested higher emissions limits for new forced draft process heaters with air preheat.

Response: The commenters provided only limited and theoretical data to support their argument that new forced draft process heaters cannot meet the 40 ppmv (or 0.040 lb/MMBtu) NO_X emissions limit. Specifically, the John Zink white paper cited by the commenter (submitted as an attachment to Docket Item No. EPA–HQ–OAR–2007–0011–0296) stated only that the 40 ppmv emissions limit could not be ''guaranteed'' for a new forced draft process heater, based on the design conditions, which included air preheat. Actual NO_X performance data for that commenter's new forced draft process heaters are not available, as those particular process heaters are not yet operational. As such, the actual performance of these forced draft process heaters is still in question. However, we acknowledge that we only have data for one new forced draft process heater without air preheat that is currently operating that could meet a 40 ppmv NO_X emissions limit on a 365-day average. We conducted additional data evaluations to determine appropriate limits and averaging times for all process heaters at normal operating conditions while considering this and other public comments we received. As part of the data analysis effort, we obtained a year's worth of hourly CEMS data for the new forced draft process heater without air preheat capable of meeting 40 ppmv on a 365-day average. As discussed later in this section, our analysis of the additional data that we obtained following the proposal supported revising all NO_X emissions limits to be on a 30-day average basis. The data indicate that the 30-day averages for the new forced draft process heater without air preheat capable of meeting 40 ppmv on a 365-day average exceeded 40 ppmv 15 percent of the time, but none of the 30-day averages exceeded 60 ppmv NO_X.

Consequently, we are raising the NO_X emissions limit (while concurrently reducing the averaging time) for all new forced draft process heaters to be equivalent to the emissions limit for modified and reconstructed forced draft process heaters (*i.e.,* 60 ppmv or 0.060 lb/MMBtu with a 30-day averaging period). Furthermore, based on the information provided by the commenters, as well as the available performance data for existing forced draft process heaters with air preheat that have been retrofitted with ultra-low NO_X burners, we also conclude that the 60 ppmv (or 0.060 lb/MMBtu) on a 30-day rolling average basis adequately accommodates forced draft process heaters that use air preheat. Based on our review of CEMS data for new and retrofitted forced draft process heaters, we conclude that 60 ppmv (or 0.060 lb/MMBtu) on a 30-day rolling average basis is BSER for new, reconstructed or modified forced draft process heaters. (For additional details, see *Revised NO_X Impact Estimates for Process Heaters,* in Docket ID No. EPA–HQ–OAR–2007–0011.)

Comment: Commenters asserted that the heating value-based emissions limits (*i.e.,* the limits in units of lb/MMBtu) should be numerically equivalent to the concentration-based emissions limits (*e.g.,* 40 ppmv should be equivalent to 0.040 lb/MMBtu rather than 0.035 lb/MMBtu).

Response: In August 2008, Industry Petitioners provided the EPA with suggestions for revising the process heater standards (Docket Item No. EPA–HQ–OAR–2007–0011–0257). One of their recommendations was to include emissions limits based on heating value (lb/MMBtu) to account for hydrogen content variations in the fuel gas. They suggested that, on an annual basis, most natural draft process heaters could meet 0.035 lb/MMBtu and all other process heaters could meet 0.055 lb/MMBtu. We evaluated these suggested emissions limits and determined that they were reasonably equivalent to the concentration-based limits we were proposing. We also requested comment on their use and their equivalency, as described in the preamble to the proposed amendments (see 73 FR 78527). Industry commenters now assert that the emissions limit numerically equivalent to the 40 ppmv concentration limit is 0.040 lb/MMBtu and the emissions limit numerically equivalent to the 60 ppmv concentration limit is 0.060 lb/MMBtu.

We note that, as discussed in the preamble to the proposed amendments, the exact conversion from ppmv to lb/MMBtu depends on the hydrogen content of the fuel gas. However, our calculations generally support the more direct numerical conversion suggested by commenters over the typical range of hydrogen concentrations expected in the fuel gas (see *Revised NO_X Impact Estimates for Process Heaters,* in Docket ID No. EPA–HQ–OAR–2007–0011). Therefore, we are finalizing heating value-based emissions limits of 0.040 lb/MMBtu and 0.060 lb/MMBtu for natural draft process heaters and forced draft process heaters, respectively, based on direct numerical conversions from the concentration-based emissions limits.

We are also clarifying that the owner or operator must demonstrate that the process heater is in compliance with either the applicable concentration-based or heating value-based NO_X limit. The heating value-based NO_X emission rate is calculated using the oxygen (O_2)-based F factor, which is the ratio of combustion gas volume to heat input. Ongoing compliance with this NO_X emissions limit is determined using a NO_X CEMS and at least daily sampling of fuel gas heat content or composition to calculate a daily average heating value-based emissions rate, which is subsequently used to determine the 30-day average.

Specifically, if the F factor is determined at least daily, the owner or operator may elect to calculate both a 30-day rolling average NO_X concentration (ppmv, dry basis, corrected to 0-percent excess air) and a 30-day rolling average NO_X emission factor (in lb/MMBtu) and demonstrate that the process heater is in compliance with either one of these limits. For most

fuel gas systems, the alternative emissions limits are expected to be identical; however, there may be instances where a process heater may be complying with one of the emissions limits and not the other. For example, a process heater combusting fuel gas with very high hydrogen content may have an average NO_X concentration above the 60 ppmv limit, but below the 0.060 lb/MMBtu limit, largely due to the concentration limit being determined on a dry basis (and understanding that the combustion of hydrogen produces only water and not carbon dioxide). Provided that the appropriate monitoring is conducted, an affected source would only be out of compliance if it exceeds both the concentration-based limit and the heating value-based limit at the same time. However, to have the option to determine compliance with the alternative heating value-based emissions limit, the refinery owner or operator must, at least daily, determine the F factor (dry basis) for the fuel gas according to the monitoring provisions in 40 CFR 60.107a(d). If the F factor is not determined at least daily, the heating value-based alternative cannot be used. Generally, fuel gas heating value is important to the overall operation of refinery boilers and process heaters; as such, refiners maintain their fuel gas within an operating range that they need to fire these sources, often by mixing with natural gas, etc., so we anticipate that most, if not all, refiners will already have this information available on a daily basis.

Comment: Several commenters addressed the need for the rule to address turndown, which is a period of time when process heaters are firing below capacity. Commenters stated that during these periods, the NO_X concentrations will likely be above the emissions limits, but the mass of NO_X emissions is no greater than when the heater is operating at full capacity because the lower firing rate results in a lower exhaust flow rate. Commenters noted that turndown conditions could exist for extended periods, so special provisions are needed for these conditions. Commenters requested a mass-based emission rate (lb/MMBtu limit multiplied by the heater's rated capacity) that would apply when the process heater is firing at less than full capacity (some commenters suggested 50 percent of capacity; one commenter suggested 70-percent capacity as a cutoff). One commenter also noted that process heaters must often operate at higher O_2 levels during turndown and requested that the proposed maximum O_2 operating limit not apply when small furnaces that are not required to install CEMS are firing at less than full capacity.

Response: In our proposed amendments, we provided a longer averaging time (365-day average) so that short periods of turn-down would not significantly affect the overall performance of the unit. However, according to the commenters, the longer averaging time does not adequately address turndown conditions. Therefore, we re-evaluated the available data, including our existing data and additional data provided by the industry, to determine the appropriate emissions limits during different types of operation, including turndown. The additional data provided by Industry and our evaluation of those data are included in the docket for the final amendments (Docket ID No. EPA–OAR–HQ–2007–0011). Based on our analysis of the data (described in greater detail in the next paragraph), we concluded that a 30-day averaging period is appropriate for the NO_X emission limits under most operating scenarios.

Upon examination of all available CEMS data, we determined that, for periods of normal operation (*i.e.,* firing at 50 percent or more of design capacity), the proposed NO_X emissions limits of 40 and 60 ppmv were not achievable for all process heaters using a 24-hour averaging period (the averaging period included in the final June 2008 rule). From the available data, short-term fluctuations in the NO_X concentrations of process heaters using ultra-low NO_X burners caused them to exceed a 24-hour average limit somewhat frequently, but a 30-day average provided adequate time to average out the short-term fluctuations. We note that a few of the process heaters operated at relatively high excess O_2 concentrations at normal conditions (*i.e.,* at exhaust O_2 concentrations of 6 percent or more). These units had periods of excess emissions above the 30-day average emission limits, but we rejected the performance of these process heaters as BSER because of the high exhaust O_2 concentrations for these units during normal (*i.e.,* non-turndown) firing rates. That is, these process heaters were not being operated optimally for reducing NO_X emissions. Furthermore, when these process heaters were operated at the lower range of exhaust concentrations for the unit (although generally higher than what would be considered optimal excess O_2 concentrations for reducing NO_X emissions), the process heater could meet the applicable 40 or 60 ppmv emissions limit on a 30-day averaging period. Based on our review of CEMS data for process heaters with ultra-low NO_X burners that operated at excess O_2 concentrations less than 6 percent (*i.e.,* operated in a manner consistent with proper low NO_X burner operation), all such process heaters could comply with the final NO_X emissions limits on a 30-day average basis. Consequently, we revised the basic emissions limits to be on a 30-day average.

As described previously in this section, we conclude that the applicable 40 or 60 ppmv emissions limit on a 30-day averaging period is achievable for process heaters during periods of normal operation. Our next step was to evaluate the achievability of the emissions limits during turndown conditions and alternative approaches for establishing emissions limitations where necessary. The following paragraphs describe our analysis of the data, including our evaluation of alternative methods for accommodating turndown conditions and our rationale for providing the site-specific alternative for extended turndown conditions.

There were very limited CEMS data available for process heaters operating under turndown conditions (*i.e.,* firing below 50 percent of design capacity). However, two general trends were observed in the CEMS data that were available: (1) Typical exhaust O_2 concentrations increase at lower firing rates; and (2) exhaust NO_X concentrations (corrected to 0-percent excess O_2) increase with increasing O_2 concentration (regardless of firing rates). These data, along with the need to operate the process heater at higher O_2 concentrations during low firing rates to maintain flame stability, suggest that an alternative NO_X emissions limit could, in some instances, be needed to address extended turndown conditions (turndown events lasting a majority of the 30-day averaging time). As such, we considered alternative compliance options to address turndown conditions.

One alternative compliance option considered to address turndown was a mass-based NO_X emissions limit that would be equivalent to the mass of NO_X emitted from a unit meeting the 0.040 (or 0.060) lb/MMBtu limit while firing at 50 percent of capacity, as suggested by commenters. However, for most units for which CEMS data are available, the alternative mass-based emissions limit did not improve the ability of the process heater to meet the emissions limit. We note that most of the process heaters were able to meet the applicable concentration-based emissions limit (40/60 ppmv) or the heating value-based (0.040/0.060 lb/MMBtu) emissions limit

during turndown. Therefore, the issue appears to be limited to a few of the process heaters that must operate at relatively high excess O_2 concentrations during turndown conditions. For these units, the alternative mass-based emissions limit that we were considering rarely, if ever, provided a means for these units to comply with the performance standard.

We understand that technology providers recommend operating process heaters that are turned down at higher excess O_2 concentrations to improve flame stability and ensure safe operation of the process heater; however, based on the information provided by the technology providers, there is still an optimal excess O_2 concentration at which flame stability is achieved while minimizing NO_X formation. That is, even when a process heater is operating at less than 50-percent design capacity, excess O_2 concentrations should still be controlled to minimize NO_X formation within the safe operating constraints to maintain flame stability. We do not have specific data on process heaters that are near, but below, the concentration emissions limits when firing above 50-percent capacity, but cannot meet the concentration limit when firing below 50-percent capacity, so we have no data that show that process heaters operating at less than 50-percent design capacity and controlling excess O_2 concentrations cannot meet the emissions limits. However, we acknowledge that the correlations with firing rates and O_2 and/or NO_X concentrations and the need for higher O_2 concentrations to maintain flame stability generally support the commenter's argument that a few marginally compliant process heaters will have difficulty meeting the basic emissions limit when the unit is turned down. As such, we acknowledge that there may be periods of turndown in which a process heater is operating as recommended, but may be unable to meet the concentration or heating value-based emissions limits in the final rule, especially when the unit is operated at turndown for extended periods (*e.g.,* for 20 days or more compared to the 30-day averaging time). As the need for an alternative limit appears to be limited to a few process heaters and the optimal O_2 concentration is expected to vary, based on fuel gas composition, we determined that a site-specific emissions limit was the best approach to account for these extended turndown conditions. As such, the final rule provides owners and operators that have a process heater operating in turndown for an extended period of time the option of developing a site-specific emissions limit that would apply to those operating conditions and requesting approval from the Administrator to use that limit.

For process heaters between 40 and 100 MMBtu/hr capacity that do not install a NO_X CEMS, turndown is also expected to be an issue with respect to achieving the O_2 operating limit. As described above, higher O_2 concentrations are generally needed to maintain flame stability at low firing rates. To address potential turndown compliance issues with the O_2 operating limit, we have provided an allowance for process heater owners or operators to develop an O_2 operating curve to provide different O_2 operating limits based on the firing rate of the process heater. If a single O_2 operating limit is established, it must be determined when the process heater is being fired at 70 percent or more of capacity (*i.e.,* far from turndown conditions). For process heaters that routinely operate at less than 50 percent of design capacity and require additional O_2 to maintain flame stability, a separate O_2 operating limit should be established for turndown by conducting a second performance test while the unit is operating at less than 50 percent of capacity. Additional performance tests can be conducted to develop O_2 operating limits for additional operating ranges.

Comment: Several commenters requested that the EPA revise the emissions limits for co-fired process heaters or remove the limits for co-fired process heaters from this rulemaking and address them at a later date due to lack of sufficient data to set an achievable emissions limit. One commenter provided a white paper to support higher emissions limits. Commenters also asserted that the averaging time for the weighted average emission rate should be extended to 365 days. One commenter noted that the notation "$E_{NOx,hour}$" in Equation 3 was confusing since the purpose of the equation was to determine the daily emission rate.

Response: The final June 2008 rule included only one emissions limit for all co-fired process heaters, and Industry Petitioners asserted that differences in the configuration and operation of different types of process heaters warranted different emissions limits. The proposed amendments introduced two specific emissions limits for co-fired process heaters, one based on vendor guarantees for the burners and one based on an average NO_X concentration for a combination of fuel gas and fuel oil. We note that, for purposes of this rule, a co-fired process heater is defined as a process heater that employs burners that are designed to be supplied by both gaseous and liquid fuels. In other words, co-fired process heaters are designed to routinely fire both oil and gas in the same burner. These do not include burners that are designed to burn gas, but have supplemental oil firing capability that is not routinely used (*i.e.,* emergency oil back-up).

To respond to the comments requesting higher emissions limits for co-fired process heaters, we reviewed the white paper provided by one commenter (submitted as an attachment to Docket Item No. EPA–HQ–OAR–2007–0011–0308), as well as additional burner emissions test data provided by another commenter[5] (conducted under well-controlled conditions using best available ultra-low NO_X burner technologies at the manufacturer's testing facility). This information indicates that, for co-fired natural draft process heaters, a daily average emissions limit calculated based on a limit of 0.06 lb/MMBtu for the gas portion of the firing and 0.35 lb/MMBtu for the oil portion of the firing is achievable. Similarly, the information indicates that, for co-fired forced draft process heaters, a daily average emissions limit calculated based on a limit of 0.11 lb/MMBtu for the gas portion of the firing and 0.40 lb/MMBtu for the oil portion of the firing is achievable. As noted above, these values are based on burner performance tests, which are considered a better source of information than the vendor guarantees that were relied upon to develop the proposed emissions limit. Therefore, we are revising the NO_X emissions limits for co-fired process heaters to those described above. We note that we have revised the concentration-based NO_X emissions limits to be on a 30-day average basis (same as the limits for gas-fired process heaters). We have also revised the nomenclature of the daily average emissions limit in Equations 3 and 4 (proposed Equation 3) to be clear that we intend the limit to be determined on a daily basis rather than on an hourly basis.

We also note that the burner performance tests were conducted in a controlled environment at the burner manufacturer's full-scale facilities. While it is incumbent on the owner or operator of an affected process heater to control certain operating parameters, such as excess O_2 concentrations, to the

[5] The commenter providing this data asserted that it is CBI. We will follow our CBI regulations in 40 CFR part 2 in handling this data. The data has been placed in the docket, but is not publicly available.

extent possible, we recognize that the performance limits in the final amendments are based on limited data, none of which are direct test data for a co-fired process heater operated at a petroleum refinery. We conclude that the low-NO_X burner technologies exist, are demonstrated and are cost effective for co-fired process heaters and they are, therefore, BSER for co-fired process heaters. However, as the performance limits are based on limited operational data, we also conclude that it is reasonable to provide an alternative, site-specific limit in the event that factors outside the influence of the burner design and operation (such as nitrogen content in the fuel oil) suggests the emission limits in the final rule are inappropriate for a specific application. Consequently, co-fired process heaters that cannot meet the limits specified above, can request approval for a site-specific emissions limit, as allowed above, for process heaters that operate for extended periods under turndown.

B. Flares

Comment: Several commenters asserted that routine connections to a flare should not be considered modifications of the flare because they do not change the maximum physical capacity of the flare and do not generally increase emissions. One commenter asserted that the 40 CFR part 60, subpart A General Provisions in 40 CFR 60.14 can and should apply to flares, so a special modification provision for flares in 40 CFR part 60, subpart Ja is unnecessary. Commenters noted that some connections to the flare have the primary purpose of reducing emissions, which has been excluded under 40 CFR 60.14(e)(5), a paragraph that is not limited to pollutants "to which the standard is applicable." One commenter noted that a single project may remove some connections and add others such that the net emissions could actually be reduced. Another commenter asserted that an increase in flow should not be considered a modification because flow is not a regulated pollutant.

Instead, commenters asserted that the modification provision for a flare should focus on physical and operational changes that increase emissions from the flare. One commenter suggested that the EPA should focus the flare modification provision on connections that provide a primary/routine flow from a process unit to the flare. Other commenters suggested that the flare modification provision should be focused on VOC and SO_2 emissions and should only include connections that result in a net increase of those pollutants emitted "during normal operations" and connections that cause an increase in the total volume of gas containing VOC or sulfur compounds under standard conditions that could reach the flare.

Response: The agency made a conscious decision to promulgate a separate provision for a flare modification in 40 CFR part 60, subpart Ja (see 40 CFR 60.14(f)) because flares are operated differently from other refinery process units, making it difficult to apply the modification provision in the General Provisions (40 CFR 60.14) to them. The physical capacity of a flare is based on the amount of gas potentially discharged to a flare as a result of emergency relief. Refiners frequently make connections to existing flares that result in emissions increases at the flares, but may never approach the physical capacity of the flare system. Contrary to commenters' assertions, the flare modification provision in 40 CFR 60.100a(c) does meet the statutory definition of "modification" in CAA section 111(a)(4), which is "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." It is axiomatic that the connections to the flare described in 40 CFR 60.100a(c) qualify as physical or operational changes to the flare. Additionally, we explained in the proposed rule how these connections also resulted in emissions increases from the flare (see 73 FR 78529). Thus, these types of new connections of refinery process units (including ancillary equipment) and fuel gas systems to the flare qualify as a "modification" of the flare and trigger subpart Ja applicability for the flare.

Those connections we identified that do not increase emissions from the flare were specifically excluded from triggering 40 CFR part 60, subpart Ja applicability under this same provision (see 40 CFR 60.100a(c)(1)). Specifically, we proposed on December 22, 2008, that the following types of connections to a flare would not be considered a modification of the flare: (1) Connections made to install monitoring systems to the flares; (2) connections made to install a flare gas recovery system; (3) 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; and (4) 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. While we agree that there may be other connections to a flare that would not result in an emissions increase from the flare (see response to the next comment for specific details), we disagree with the commenters that the flare modification provision should be further limited beyond what is already provided in the provision.

We disagree with commenters that we must consider the "net" emissions from the process unit and the flare when determining whether a flare is modified. The affected facility is the flare and does not include the process units that are tied into the flare header system. *See Asarco* v. *EPA,* 578 F.2d 319, 325 (D.C. Cir. 1978) (holding that emission increases had to be determined based on emissions from the affected facility). We also disagree that a modification determination should be limited to emissions increases of VOC or SO_2. Flares are known to emit VOC, SO_2, carbon monoxide (CO), PM and NO_X, as well as other air pollutants, all of which are relevant when determining whether a flare has been modified. See CAA section 111(a)(4). That is, we consider the standards for flares to be emission standards for VOC, SO_2, CO, PM and NO_X. See, generally, 73 FR 35838, 35842, 35854–35856 (June 24, 2008); 73 FR 78522, 78533 (December 22, 2008), as well as Table 4 of this preamble. Using the flare to control VOC emissions at other refinery process units will increase CO, PM and NO_X emissions from the flare and are, therefore, considered modifications of the flare, even if there is a net reduction in VOC emissions at the refinery.

In evaluating whether a flare has been modified, we consider increases in flow to the flare to be directly indicative of increased emissions from the flare. While we agree that "flow" is not a pollutant, we evaluated flow limits as a means to reduce SO_2, VOC, CO, NO_X and other emissions from the flare. The emissions from the flare are very difficult, if not impossible, to measure accurately, but flow to the flare can be measured, and the flow to the flare generates SO_2, VOC, CO, PM, NO_X and other emissions. Therefore, a physical or operational change to a flare that causes an increase of flow to the flare will increase emissions of at least one of these pollutants and is considered a modification of the flare.

Comment: Many commenters responded to the EPA's request for comment on types of connections that

do not result in an increase in emissions from a flare. The commenters suggested numerous specific connections that should not be considered modifications, including:

(1) Connections made to upgrade or enhance (not just to install) a flare gas recovery system;

(2) Connections made for flare gas sulfur removal;

(3) Connections made to install back-up equipment;

(4) Flare interconnects;

(5) All emergency pressure relief valve connections from existing equipment;

(6) Connections of monitoring system purge gases and analyzer exhausts or closed vent sampling systems;

(7) Purge and clearing vapors, block and bleeder vents and other uncombusted vapors where the flare is the control device;

(8) Connections made to comply with other federal, state or local rules where the flare is the control device;

(9) Connections of ''unregulated gases'' such as hydrogen, nitrogen, ammonia, other non-hydrocarbon gases or natural gas or any connection that is not fuel gas;

(10) New connections upstream of an existing flare gas recovery system, provided the new connections do not compromise or exceed the flare gas recovery system's capacity;

(11) Any new, moved or replaced piping or pressure relief valve connections that do not result in a net increase in emissions from the flare, regardless of piping or pressure relief valve size;

(12) Vapors from tanks used to store sweet or treated products;

(13) Temporary connections for purging existing equipment, as these are essentially ''existing'' connections; and

(14) Connections of safety instrumentation systems (SIS) described under Occupational Safety and Health Administration (OSHA) process safety standards at 29 CFR 1910.119, the EPA's risk management program at 49 CFR 68 and/or American National Standards Institute (ANSI)/International Society of Automation (ISA)-84.00.01–2004.

Response: We carefully reviewed the commenters' suggested changes to the flare modification provision to determine whether there are additional connections that should not be considered modifications to the flare. We agree that the first four connections in the commenters' list should not be considered modifications of a flare. Projects to upgrade or enhance components of a flare gas recovery system (*e.g.,* addition of compressors or recycle lines) will improve the operation of the flare gas recovery system, and connections to these additional components will not result in increased emissions. Connections made for removal of sulfur from flare gas (Item 2 above) will generally result in a slight decrease in volumetric flow and a large decrease in emissions of SO_2. Connections made to install back-up or redundant equipment (Item 3 above), such as a back-up compressor, will result in fewer released emissions if there is a malfunction in the main equipment.

The request to exclude flare interconnections (Item 4 above) is a complicated issue because interconnecting two separate flares alters what we consider to be the affected facility. The definition of ''flare'' specifically includes the flare gas header system as part of the flare. Prior to interconnecting the flares, presumably each flare header system is independent, and there would be two separate ''flares,'' each of which could potentially be an affected facility subject to 40 CFR part 60, subpart Ja. However, because the flare includes the flare header system, we consider that an interconnected flare system is a single affected facility, and we have amended the definition of ''flare'' for clarity. We agree that interconnections between flares will not alter the cumulative amount of gas being flared (*i.e.,* interconnecting two flares does not result in an emissions increase relative to the two single flares prior to interconnection). We also see cases where the emissions from a single flare tip will likely be reduced due to the flare interconnect. For example, when a large release event occurs, this gas will now flow to both of the interconnected flares rather than a single flare. The maximum emission rate for the original single flare actually decreases, while the combined emissions from both flares is the same quantity as prior to the interconnection. Considering this, we agree that the interconnection of two flares does not necessarily result in a modification of the flare and we have specifically excluded flare interconnections from the modification provisions.

However, we also clarify in this response that when a flare that is subject to 40 CFR part 60, subpart Ja is interconnected with a flare that is not subject to subpart Ja, then the resulting interconnected flare is subject to subpart Ja. That is, the only case in which an interconnection between two (or more) flares results in a combined, interconnected flare that is not subject to subpart Ja is when none of the original individual flares were subject to subpart Ja. Additionally, we note that if a new connection is made to the interconnected flare, then the flare (including each individual flare tip within the interconnected flare header system) is modified and becomes an affected facility subject to subpart Ja.

While we agree that connections that do not increase the emissions from the flare should not trigger a modification, we disagree with the commenter that their other suggested connections do not increase the flare's emissions at the time gases are discharged via the new connection. Each of the commenters' suggestions is discussed in the following paragraphs.

We previously proposed an exemption for emergency pressure relief valve connections from existing equipment (Item 5 above) if they replace or upgrade existing equipment and do not increase the instantaneous release rate to the flare (*i.e.,* the new pressure relief valve has a pressure set point and diameter no greater than the equipment being replaced). As stated previously in this preamble, we are finalizing that amendment, as proposed. However, new connections, even if they are made to ''existing equipment,'' will result in an increase in flow to the flare during periods of process upset that cause the pressure relief valve to open.

Connections of monitoring system purge gases and analyzer exhausts or closed vent sampling systems (Item 6 above) will increase the emissions from the flare. Similarly, connections of purge and clearing vapors and block and bleeder vents (Item 7 above), also trigger a modification of the flare because the increase of gas flow to the flare will increase the emissions from the flare.

We recognize that connections to a flare may be made to comply with other federal, state or local rules where the flare is an emissions control device (Item 8 above). In fact, nearly all flares could be considered ''control devices.'' We agree that using a flare as an emissions control device is preferable to venting the process unit to the atmosphere. However, while using the flare as an emissions control device does decrease emissions from the process unit being controlled, the increase of gas flow to the flare will increase the emissions from the flare. Therefore, a connection from a process unit to a flare for use as an emissions control device results in a modification of that flare.

Comments suggesting that connections of ''unregulated gases'' such as hydrogen, nitrogen, ammonia, other non-hydrocarbon gases or natural gas or connections that are not ''fuel gas,'' should not be considered a

modification of the flare (Item 9 above) are in conflict with the statutory definition of ''modification.'' Each of the streams mentioned by the commenter, when directed to a flare, will increase emissions of at least one pollutant (either PM, CO or NO_X) from the flare (all of which the standard is intended to reduce). That is, we reiterate that we consider the standards for flares to be emission standards for VOC, SO_2, CO, PM and NO_X. As such, we do not agree that the types of gas streams suggested by the commenters should be exempt from the modification determination.

New connections upstream of an existing flare gas recovery system (Item 10 above) will increase the likelihood of an event that would cause an exceedance of the flare gas recovery system's capacity (even if the new connections ''do not exceed the flare gas recovery system's capacity'' under normal conditions), and the amount of gases sent to the flare would increase as a result of such an event, thereby increasing the emissions from the flare.

We reiterate that we proposed an exemption for any moved or replaced piping or pressure relief valve connections of the same size. However, we disagree with the commenter's suggestion that any ''new, moved, or replaced piping or pressure relief valve connections that do not result in a net increase in emissions from the flare regardless of piping or pressure relief valve size'' should be exempted (Item 11 above). The premise of the suggested amendment is that new or larger connections somehow will not increase emissions from the flare. We have discussed new connections previously, so we will concentrate on the ''regardless of piping or pressure relief valve size'' comment in this paragraph. First, the size of the pressure relief valve or piping does correlate to the discharge rate to the flare, with larger pressure relief valves or larger diameter piping allowing higher discharge rates to the flare at a given pressure. In fact, larger pressure relief valves and larger diameter pipes are specifically designed to allow higher flow rates to the flare. Second, higher flow rates will lead to higher emission rates. For a pressure relief event that occurs for several hours, the flow rate to the flare during the first hour of relief using the larger pressure relief valve or larger diameter piping will be larger than the flow rate experienced using the smaller pressure relief valve or smaller diameter piping and will result in higher emissions from the flare. Therefore, we reject the notion that larger diameter pipes and larger pressure relief valves do not increase the emissions rate from the flare during a release event. We are finalizing the proposed exemptions for moved or replaced piping or pressure relief valves with the size and design restrictions for the new piping or pressure relief valves as proposed on December 22, 2008.

Commenters suggested that connections of vapors from tanks used to store sweet or treated products (Item 12 above) should not be modifications because those gas streams have less than 162 ppmv H_2S. We reiterate that SO_2 is not the only pollutant emitted from flares and that the additional flow of sweet gases will increase the emissions of at least one pollutant from the flare, so we are not exempting these types of connections to the flare from the 40 CFR part 60, subpart Ja flare modification provision. However, we have amended the sulfur monitoring requirements for flares to exempt vapors from tanks used to store sweet or treated products from the flare sulfur monitoring requirements. This monitoring exemption is justified because it is not needed for the purposes of a root cause analysis or other compliance purpose. For these sweet vapors, the flow rate root cause analysis threshold will be exceeded well before the SO_2 root cause analysis threshold.

We carefully considered temporary connections for purging existing equipment (Item 13 above), but we failed to see how these temporary connections are essentially ''existing connections.'' According to the commenters, ''maintenance gases have been routed in some form or other to the flare for years, and the temporary tie-in to accomplish that is not a change and is not an increase in emissions when viewed from a before and after perspective.'' If the connections already exist, then opening an existing valve to allow for this type of purging would not trigger a flare modification. If the connection is being relocated and the piping used is the same diameter as the pre-existing connection, then this scenario is adequately covered by the proposed exclusion for relocated connections. However, if a new connection is made specifically to purge an existing piece of equipment, this purge gas unequivocally represents additional gas flow sent to the flare that did not exist and could not exist prior to the connection being made. Again, we consider that the increase in gas flow to the flare will result in an increase in emissions of at least one pollutant from the flare. As such, no exemption is provided for new connections to existing equipment, regardless if these connections are temporary or permanent. We also find that these types of flows should be expressly considered in the flare management plan and that flaring from these ''temporary'' connections should be minimized to the extent practicable.

The impact of connections of SIS described under OSHA process safety standards at 29 CFR 1910.119, the EPA's risk management program at 49 CFR 68 and ANSI/ISA–84.00.01–2004 (Item 14 above) should be evaluated on a case-by-case basis to determine whether these connections result in a flare modification. We expect that, if these connections are made for flare monitoring purposes, these connections are already excluded in the exemption for flare monitoring systems. If the ''SIS'' are process unit analyzers and the new connections are being made to connect the analyzer exhaust to the flare, these connections would be considered a modification, as previously discussed. The commenter may also be referring to new connections for additional pressure relief valves identified in the safety reviews required by the cited rules, which we would consider to be a modification of the flare.

Following all of the above review and analysis, we are finalizing three of the connections, as proposed, adding three of the connections requested by commenters and revising one of the proposed connections as requested by commenters in 40 CFR 60.100a(c)(1). Thus, the following seven types of connections are not considered a modification of the flare:

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

(2) Connections made to install a flare gas recovery system or connections made to upgrade or enhance components of a flare gas recovery system (*e.g.*, addition of compressors or recycle lines).

(3) 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.

(4) Connections that interconnect two or more flares.

(5) Connections made for flare gas sulfur removal.

(6) Connections made to install back-up (redundant) equipment associated with the flare (such as a back-up compressor) that does not increase the capacity of the flare.

(7) 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.

Comment: Several commenters suggested that *de minimis* emission increases and net emission decreases resulting from new connections to a flare made to control and combust fugitive emissions such as leaks from compressor seals, valves or pumps, should not be considered modifications of a flare. One commenter suggested allowing site-specific exemptions for connections that do not increase emissions or that result in a *de minimis* emissions increase. However, another commenter objected to setting a *de minimis* emissions increase to determine whether a change to a flare is a modification and stated that allowing a *de minimis* approach would cause confusion over the applicability of 40 CFR part 60, subpart Ja because flare emissions are difficult to estimate.

Response: In the preamble to our proposed amendments, the EPA specifically requested comment on using the *de minimis* exception in the flare modification provision. 73 FR 78522, 78529. Industry Petitioners had suggested some type of *de minimis* emissions increase should be allowed without triggering 40 CFR part 60, subpart Ja applicability. *Id.* The EPA acknowledged that these exceptions are ''permissible but not required'' under the modification provision in the CAA. *Id.* The EPA also stated: ''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.'' Id.*

Industry Petitioners continue to recommend that any emissions increases resulting from ''routine connections'' to the flare system ''will be *de minimis''* and should not trigger 40 CFR part 60, subpart Ja applicability at the flare, but they have not provided the comments or data requested in the proposal preamble that the EPA could consider to evaluate the impacts of such an approach. Docket Item No. EPA–HQ–OAR–2007–0011–0311 (second attachment), pg 20. Industry Petitioners again suggest that the EPA exercise its authority and ''authorize exceptions from otherwise clear statutory mandates'' by promulgating *de minimis* exemptions for the flare modification provision. *Id.; Alabama Power Co.* v. *Costle,* 636 F.2d 323, 360 (D.C. Cir. 1979). As explained in *Alabama Power,* the *de minimis* exception allows agency flexibility in interpreting a statute to prevent ''pointless expenditures of effort.'' *Id.* However, as Industry Petitioners recognize, nothing mandates that the EPA use its *de minimis* authority in any given instance, and courts especially recognize the significant deference due an agency's use of a *de minimis* exception. *Id.* at 400; *Shays* v. *Federal Election Com'n,* 414 F.3d 76, 113 (D.C. Cir. 2005); *Environmental Defense Fund, Inc.* v. *EPA,* 82 F.3d 451, 466 (D.C. Cir. 1996); *Ass'n of Admin. Law Judges* v. *Fed. Labor Relations Auth.,* 397 F.3d 957, 961 (D.C. Cir. 2005).

In exercising that discretion, the EPA must consider the cautionary advice it received from the *Alabama* Court regarding its use of the *de minimis* exception: ''EPA must take into account in any action * * * that this exemption authority is narrow in reach and tightly bounded by the need to show that the situation is genuinely *de minimis.'' Id.* at 361. The Court also noted that exemptions from ''the clear commands of a regulatory statute, though sometimes permitted, are not favored.'' *Id.* at 358. The EPA must exercise this authority cautiously, and only in those circumstances that truly warrant its application.

The EPA has found no basis for promulgating a *de minimis* exception to the flare modification provision. Despite its assertions, Industry Petitioners have still provided no data to support a finding that the emissions increases resulting from the alleged ''routine connections'' to a flare system are truly ''trivial or [of] no value.'' Docket Item No. EPA–HQ–OAR–2007–0011–0311 (second attachment), pg 20. Without the requested information showing that ''the situation is genuinely *de minimis,''* *Alabama Power,* 636 F.2d at 361 and, therefore, warrants this kind of exception, we believe such an exemption would be inappropriate.

Additionally, Industry Petitioners' example that ''venting a new small storage tank to a flare system * * * easily would cost a typical refinery tens of millions of dollars'' since ''the *entire* flare system'' (emphasis in original) would be subject to subpart Ja is unavailing for its argument that the EPA should promulgate a *de minimis* exception for the flare modification provision. Docket Item No. EPA–HQ–OAR–2007–0011–0311 (second attachment), pg 21. As the District of Columbia Circuit specifically states in *Shays,* authority for promulgating a *de minimis* exception ''does *not* extend to a situation where the regulatory function does provide benefits, in the sense of furthering regulatory objectives, *but the agency concludes the acknowledged benefits are exceeded by the costs.'' Shays,* 414 F.3d 76, 114 (emphasis added). By focusing solely on cost, Industry Petitioners are effectively asking the agency to engage in the type of cost-benefit analysis prohibited by the *Shays* Court. Such cost analyses are improper in these types of decisions. Industry Petitioners generally focus their discussion on VOC emissions and effectively admit that connecting the small storage tank to the flare system increases emissions from the flare (*e.g.,* ''uncontrolled tank emissions would be *essentially* eliminated by combustion in a flare'' (Docket Item No. EPA–HQ–OAR–2007–0011–0311 (second attachment), pg 21, emphasis added)). Furthermore, they disregard additional emissions of NO_X and CO resulting from the combustion of these gases at the flare. Industry Petitioners also provide no data quantifying these emissions increases and, therefore, cannot demonstrate that they are ''trivial or [of] no value'' or, in other words, that the emissions increases are, in fact, *de minimis.* As releases to the flare are often event driven, one can envision situations where the release from even a small storage tank could be significant. On the other hand, the EPA sees a substantial environmental benefit in requiring controls that will reduce the cumulative emissions from a flare that becomes subject to 40 CFR part 60, subpart Ja because of any of these alleged ''routine connections.'' Thus, given the nature of releases to the flare, we determined that a *de minimis* exemption from the modification provisions for flares is unworkable and unwarranted.

Comment: One commenter stated that exempting flares [6] from the H_2S concentration limits during startup, shutdown and malfunction (SSM) events is illegal because the CAA requires continuous compliance with standards of performance promulgated under CAA section 111. See CAA sections 111(a)(1), 302(k). For support, the commenter cited *Sierra Club* v. *EPA,* 551 F.3d 1019 (DC Cir. 2008), in which the Court stated: ''When sections 112 and 302(k) are read together, then, Congress has required that there must be continuous section 112-compliant standards.'' The commenter noted that the Court found that the exemption from compliance with CAA section 112 standards during SSM events violates

[6] The comments submitted referenced ''fuel gas combustion devices'' as the affected source when describing the exemption during SSM events. However, the exemption only applies to flares. See 40 CFR 60.103a(h). The discussion in this preamble is, therefore, focused on flares as distinguished from other types of fuel gas combustion devices that are required to comply at all times with the H_2S concentration limits in 40 CFR 60.102a(g)(1).

the CAA because the general duty to minimize emissions during SSM events is not a CAA section 112-compliant standard. The commenter asserted that the CAA also requires that a section 111-compliant standard that reflects BSER[7] be in effect at all times for flares.

The commenter further asserted that work practice standards for flares are not CAA section 111-compliant standards because this is not one of those "limited instances" in which CAA section 111(h) authorizes such standards. The commenter stated that the EPA must show that a standard of performance for flares is "not feasible to prescribe or enforce" because "(A) a pollutant * * * cannot be emitted through a conveyance designed and constructed to emit or capture such pollutant, or that any requirement for, or use of, such a conveyance would be inconsistent with any federal, state or local law or (B) the application of measurement methodology to a particular class of sources is not practicable due to technological or economic limitations." See CAA section 111(h)(2). The commenter stated that neither of these exemptions appear to apply and the EPA cannot claim that it is infeasible to promulgate a standard of performance for flares,[8] so the EPA cannot set a work practice standard for flares. Thus, the commenter asserted that a CAA section 111-compliant standard does not continuously apply to flares since both the exemption from the H_2S concentration limits during SSM events and the flare work practice standards are not lawful under the CAA.

Another commenter disagreed and provided several reasons why they believe the EPA may lawfully exempt flares from the H_2S concentration limits during SSM events. First, the commenter noted that 40 CFR part 60, subpart Ja was promulgated as part of the mandatory periodic review of 40 CFR part 60, subpart J required by CAA section 111(b)(1)(B). The commenter noted that subpart J exempts a flare from the H_2S concentration limits when combusting certain gases generated during SSM events (see 40 CFR 60.104(a)(1), 60.101(e)) and stated that the record contains "ample evidence" to support maintaining that provision in subpart Ja. The commenter asserted that including these same provisions in subpart Ja is "an appropriate exercise of EPA's authority to 'not review' this aspect of the existing standard in light of the efficacy of the existing standard." See CAA section 111(b)(1)(B).

Second, the commenter noted that the *Sierra Club* decision was largely grounded in the Court's determination that Congress amended CAA section 112 out of concern "about the slow pace of EPA's regulation of HAPs," eliminating much of the EPA's discretion and requiring sources to "meet the strictest standards" without variance "based on different time periods." The commenter further explained that the Court pointed to CAA section 112(d)(1) regarding the EPA's authority to "distinguish among classes, types, and sizes of sources" when promulgating CAA section 112 standards as further evidence for constraining the EPA's ability to adopt different standards applicable during SSM events. In contrast, the commenter asserted that "Congress has expressed no such concern about EPA's efforts to implement section 111" despite revisions to CAA section 111 in 1977 and 1990. Therefore, the commenter asserted, Congress has "effectively ratified EPA's longstanding approach to SSM under the NSPS program," which includes the exemption for flares from the H_2S concentration limits during SSM events.

The commenter also asserted that, regardless of the above and despite the similar nature of the provisions in CAA sections 111 and 112, the EPA has the discretion to implement them differently "under the markedly differently context of the NSPS program v. the MACT program." See *Environmental Defense* v. *Duke Energy Corp.,* 549 U.S. 561, 575–576 (2007). For example, the commenter asserted that the word "continuous" as used in the NSPS program could be interpreted and applied differently, as acknowledged by the Court in *National Lime Ass'n* v. *EPA,* 627 F.2d 416, 434 (DC Cir. 1980) (deferring to agency regarding the effect of "the perplexing implications of Congress' new requirement of systems of continuous emission reduction" on the agency's longstanding "regulations permitting flexibility to account for startups, shutdowns, and malfunctions"). The commenter urged the EPA to exercise this discretion and "reassert the many practical, technical and economic factors" that justify promulgating separate standards for SSM events in the NSPS program.

Third, the commenter asserted that requiring flares to meet the H_2S concentration limits during SSM events does not represent BSER for this time period. According to the commenter, "startup and shutdown gases are intermittent streams that cannot be cost effectively treated for sulfur removal because of their infrequent occurrence, their scattered points of generation and their variability." Therefore, for all of the above reasons, the commenter asserted that exempting a flare from the H_2S concentration limits when combusting certain gases generated during SSM events is lawful under CAA section 111.

Alternatively, the commenter stated that if a standard must apply during SSM events, the flare work practice standards are appropriate in lieu of the H_2S concentration limit.

Response: Regardless of whether or how the *Sierra Club* decision under CAA section 112 applies to NSPS promulgated under CAA section 111, we are promulgating final amendments for flares that include a suite of standards that apply at all times and are aimed at reducing SO_2 emissions from flares. As described previously, this suite of standards requires refineries to: (1) Develop and implement a flare management plan; (2) conduct root cause analysis and take corrective action when waste gas sent to the flare exceeds a flow rate of 500,000 scf above the baseline; (3) conduct root cause analysis and take corrective action when SO_2 emissions exceed 500 lb in a 24-hour period; and (4) optimize management of the fuel gas by limiting the short-term concentration of H_2S to 162 ppmv during normal operating conditions. Additionally, refineries must install and operate monitors for measuring sulfur and flow at the inlet of all of their flares. Together, these requirements provide CAA section 111-compliant standards that collectively cover all operating conditions of the flare.

As the commenter notes, CAA section 111(h)(1) allows the EPA to promulgate a design, equipment, work practice or operational standard or "combination thereof," when "it is not feasible to prescribe or enforce a standard of performance" which reflects BSER for the particular affected source. CAA section 111(h)(2) defines the phrase

[7] The commenter asserted, without providing support, that it is not BSER to exempt flares from the H_2S concentration limits during startup and shutdown events. The commenter also stated that the EPA, at a minimum, must demonstrate how the exemption from the H_2S concentration limits during SSM events does, in fact, represent BSER, but the commenter stated that the EPA has failed to make this demonstration.

[8] The commenter cited the EPA's rationale for proposing work practice standards for flaring in which we state: "It is not feasible to prescribe or enforce a standard of performance for these sources because either the pollution prevention measures eliminate the emission source, so that there are no emissions to capture and convey, or the emissions are so transient, and in some cases, occur so randomly, that the application of a measurement methodology to these sources is not technically and economically practical." 72 FR 27178, 27194–27195 (May 14, 2007). In response, the commenter stated: "[T]he plain language of the Act recognizes that standards of performance leading to the 'capture' of emissions are not infeasible [citation omitted], and EPA has proposed to apply measurement methodologies to flares in spite of the transience of their emissions."

"not feasible to prescribe or enforce a standard of performance" as "any situation in which the Administrator determines that * * * a pollutant or pollutants cannot be emitted through a conveyance designed and constructed to emit or capture such pollutant, or that any requirement for, or use of, such a conveyance would be inconsistent with any Federal, State, or local law, or * * * the application of measurement methodology to a particular class of sources is not practicable due to technological or economic limitations."

We have determined that flares meet the criteria set forth in CAA section 111(h)(2)(A) because emissions from a flare do not occur "through a conveyance designed and constructed to emit or capture such pollutant." Gases are conveyed to the flare for destruction, and combustion products such as SO_2 are not created until combustion occurs, which happens in the flame that burns outside of the flare tip. In other words, the SO_2, NO_X, PM, CO, VOC and other pollutants generated from burning the gases are only created once the gases pass through the flare and come into contact with the flame burning on the outside of the flare. The flare itself is not a "conveyance" that is "emitting" or "capturing" these pollutants; instead, it is a structure designed to combust the gases in the open air. Thus, setting a standard of performance for SO_2 (and other pollutants) is not "feasible," allowing the EPA to instead promulgate standards under CAA section 111(h), which will collectively limit emissions from the flare.

The EPA previously promulgated a standard of performance for SO_2 emissions for fuel gas combustion devices which also applied to flares. 39 FR 9308, 9315 (March 8, 1974). The standard is expressed as an H_2S concentration limit because it was developed as an alternative to measuring the SO_2 concentration in the stack gases exiting fuel gas combustion devices other than flares (*i.e.,* boilers and process heaters). That approach is appropriate for fuel gas combustion devices other than flares because measuring the H_2S in the fuel gas combusted in those devices is directly indicative of the SO_2 emitted from the exhaust stacks of those other devices. As explained in section III of this preamble, we are, for the first time, designating flares as their own affected facility. As such, in finalizing these amendments for flares, we considered whether we could also apply a standard of performance for SO_2 emissions, expressed as an H_2S concentration limit or a total sulfur limit at the inlet to the flare. However, as explained above, flares are substantially different from other fuel gas combustion devices so that this approach is not workable for flares. For example, SO_2 emissions from a flare are dependent on many factors, including the flow rates of all gases sent to the flare, the total sulfur content of all gases sent to the flare and the combustion efficiency at the flare. Each of these factors is also dependent on many variables. For example, combustion efficiency at the flare is dependent upon the flammability of the gases entering the flare, the turbulence at the flare,[9] the wind speed and wind direction and the presence of other pollutants in the gases that can react with the sulfur to form sulfur-containing pollutants other than SO_2. Since so many factors affect the potential formation of SO_2 emissions outside the flare tip, we realized that we could not properly derive an H_2S concentration limit or a total sulfur limit at the flare inlet that would directly correlate with those SO_2 emissions. Thus, we determined that we cannot set a standard of performance for SO_2 emissions at the flare.

However, we still recognize that reducing the amount of sulfur that is sent to a flare will reduce the SO_2 emissions at the flare. Even with the uncertainty described above, we understand the importance of refineries managing the fuel gas sent to their flares in a way that minimizes the sulfur content so as to ultimately minimize the SO_2 emissions. Rather than eliminate the H_2S concentration limit altogether, we are instead requiring under CAA section 111(h) that refineries limit the short-term concentration of H_2S to 162 ppmv in the fuel gas sent to flares during normal operating conditions. Refineries rely on various methods for optimizing the management of fuel gas, including the use of amine treatment and flare gas recovery systems. Amine treatment removes the H_2S from the flare gas that generates the pollutants before the gas is sent to the flare. Flare gas recovery systems remove the flare gas altogether and instead treat this gas in a fuel gas treatment system to be used elsewhere as fuel gas in the refinery. Requiring refineries to meet this concentration limit at the flare ensures that the fuel gas has been adequately treated and managed such that it can be used as fuel gas in the fuel gas system elsewhere in the refinery. We are not requiring refineries to meet this limit during other periods of operation because flare gas recovery systems that capture gases prior to amine treatment can be quickly overwhelmed and fail to properly function during high fuel gas flows. Thus, requiring that flares meet this H_2S concentration limit during periods when high fuel gas flows would likely overwhelm these flare gas recovery systems would not fully address the circumstances refineries face in managing these high flow periods. Designing flare gas recovery systems to capture the full range of gas flows to the flare would not only require the ability to predict the full range of gas flows in the flare headers, but also would require refiners to install recovery compressors in a staged fashion such that all events causing high gas flows could be captured and managed, neither of which are practical. Therefore, promulgating flare requirements that include the H_2S fuel gas concentration limit during normal operating conditions, coupled with requirements for refineries to develop and implement a flare management plan and conduct root cause analyses and take corrective action when waste gas sent to the flare exceeds a flow rate of 500,000 scf above the baseline or 500 lb of SO_2 in a 24-hour period, recognizes these unique circumstances while still requiring the refinery to take all reasonable measures for reducing or eliminating the flow and sulfur content of gases being sent to the flares.

We are aware that numeric SO_2 emission limits for flares have been established under state law and in Federal Implementation Plan (FIP) regulatory requirements. Those source-specific circumstances differ markedly from this nationally applicable rulemaking, necessitating different decisions in two very different circumstances. For example, the EPA's SO_2 FIP for the Billings/Laurel, Montana area includes a SO_2 emission limit of 150 lb of SO_2 per 3 hours for four sources that apply to the flares at all times. See 40 CFR 52.1392(d)(2)(i), (e)(2)(i), (f)(2)(i) and (g)(2)(i). These source-specific limits were appropriately based on dispersion modeling in the Billings/Laurel area to determine what was needed to meet national ambient air quality standards (NAAQS) for SO_2 in the Billings/Laurel area. In contrast, the nationally applicable standards and requirements we are promulgating in this rule must represent the BSER achievable for an entire industry sector scattered across the entire country. This requires that we consider costs and other non-air quality factors that affect all petroleum refineries nationwide in making that decision and not just as applied to a

[9] Turbulence is needed to insure good mixing at the flare, but is affected by whether the flare is assisted with air or steam or non-assisted.

particular group of sources in a particular location.

Additionally, those four sources subject to the Billings/Laurel FIP demonstrate compliance with the 150 lb SO_2/3-hour emission limit by measuring the total sulfur concentration and volumetric flow rate of the gas stream at the inlet to the flare. See 40 CFR 52.1392(d)(2)(ii), (e)(2)(ii), (f)(2)(ii), (g)(2)(ii) and (h). Since the FIP must include emissions limits that insure attainment and maintenance of the NAAQS in the Billings/Laurel area, it was appropriate, in setting the standards for the Billings/Laurel FIP, to conservatively assume that 100 percent of the sulfur in the gases discharged to the flare is converted to SO_2, and based on this conversion, set the numeric limit as a value that is not to be exceeded. However, that same assumption is not appropriate when setting national standards for flares. Instead, we must consider the many factors affecting the formation of SO_2 at the flare tip and how these factors affect how much of the sulfur in the gases sent into the flare actually converts to SO_2. Therefore, although setting such source-specific limits was appropriate to satisfy what the modeling showed was necessary to meet the SO_2 NAAQS in the Billings/Laurel area, a different analysis and standard is appropriate for a national rulemaking.

Therefore, for the reasons discussed above, the EPA is finalizing this collective set of CAA section 111(h)-compliant standards for flares, based on our interpretation of CAA section 111(h) as it applies to flares.

Comment: Numerous commenters asserted that the long-term 60 ppmv H_2S fuel gas concentration limit is not cost effective for flares and, therefore, not BSER for flares. The commenters noted that the EPA did not include costs for compressors, additional amine units and sulfur recovery units, and one commenter stated that the EPA did not consider the range of costs that are incurred by individual refineries. Commenters also asserted that the EPA overstated emission reductions by using 162 ppmv H_2S as a baseline because many refinery streams currently sent to the flare contain H_2S concentrations below 162 ppmv, so 162 ppmv H_2S does not reflect long-term performance. Commenters noted that the British thermal units (Btu) content of flare gas is highly variable and generally lower than that used by the EPA, so the EPA's analysis overestimated the value of the recovered flare gas. One commenter noted that the EPA should have considered consent decree requirements in the baseline SO_2 emissions estimates.

One commenter stated that the long-term 60 ppmv H_2S fuel gas concentration limit could preclude some refineries from processing high-sulfur crude oils, thereby limiting refining production capacity. Another commenter noted that many flares will receive both fuel gas and process upset gas, so it would be impossible to determine if an exceedance is caused by the regulated fuel gas or by the exempt gas. The commenter recommended that the EPA apply the long-term 60 ppmv H_2S fuel gas concentration limit only to fuel gas combusted in process heaters, boilers and similar fuel gas combustion devices, and not to flares, or that the EPA allow Alternative Monitoring Plans to demonstrate compliance with the emissions limits for non-exempt gas streams upstream of the flare header.

Response: We acknowledge that, at proposal, we determined that a long-term 60 ppmv H_2S fuel gas concentration limit was cost effective primarily for process heaters, boilers and other fuel gas combustion devices that are fed by the refinery's fuel gas system. Based on the typical configuration at a refinery, adding one new fuel gas combustion device to the fuel gas system would essentially require the owner or operator to limit the long-term concentration of H_2S in the entire fuel gas system to 60 ppmv, so emission reductions would result from all fuel gas combustion devices tied to that fuel gas system. Upon review of the BSER analysis conducted at proposal for fuel gas combustion devices, we now realize that the analysis is not applicable to flares (See Docket Item No. EPA–HQ–OAR–2007–0011–0289).

Moreover, since we are regulating flares separately from other fuel gas combustion devices in this final rule, we should separately consider whether a long-term H_2S concentration limit is appropriate for fuel gas sent to flares.

In developing the suite of CAA section 111(h) standards for flares, we considered whether refineries should be required to optimize management of their fuel gas by limiting the long-term H_2S concentration to 60 ppmv in addition to the short-term H_2S concentration of 162 ppmv during normal operating conditions. We determined that, for refineries to demonstrate that their fuel gas complies with a long-term H_2S concentration of 60 ppmv, refineries would have to install a flare gas recovery system (which was not needed for other fuel gas combustion devices) and then upgrade the fuel gas desulfurization system. Alternatively, refineries would have to treat the recovered fuel gas to limit the long-term concentration of H_2S to 60 ppmv with new amine treatment units on each flare.

While some of the costs provided by the commenters did not include the value of the recovered gas and appeared, at times, to include equipment not necessarily required by the regulation, we generally agree with the commenters, based on our own cost estimates, that optimizing management of the fuel gas system to limit the long-term concentration of H_2S to 60 ppmv is not cost effective for flares (see Table 4 below). We note that the costs provided by the commenters and the costs and emissions reductions in our analysis are the incremental costs and emissions reductions of going from the short-term 162 ppmv H_2S concentration to a combined short-term 162 ppmv H_2S concentration and long-term 60 ppmv H_2S concentration. While we are aware that some consent decrees require refineries to limit the concentration of H_2S in the fuel gas to levels lower than the short-term 162 ppmv H_2S concentration, our baseline when evaluating the impacts of a national standard (in this case, 40 CFR part 60, subpart Ja) is the national set of requirements to which an affected flare would be subject in the absence of subpart Ja (*i.e.,* the short-term 162 ppmv H_2S concentration limit in 40 CFR part 60, subpart J).

TABLE 4—NATIONAL FIFTH YEAR IMPACTS OF MEETING A LONG-TERM 60 PPMV H_2S CONCENTRATION FOR FLARES SUBJECT TO 40 CFR PART 60, SUBPART JA

	Capital cost ($1,000)	Total annual cost ($1,000/yr) [a]	Emission reduction (tons SO_2/yr) [b]	Emission reduction (tons NO_X/yr) [b]	Emission reduction (tons VOC/yr) [b]	Cost effectiveness ($/ton)
New	80,000	15,000	6	34	130	84,000

TABLE 4—NATIONAL FIFTH YEAR IMPACTS OF MEETING A LONG-TERM 60 PPMV H_2S CONCENTRATION FOR FLARES SUBJECT TO 40 CFR PART 60, SUBPART JA—Continued

	Capital cost ($1,000)	Total annual cost ($1,000/yr) [a]	Emission reduction (tons SO_2/yr) [b]	Emission reduction (tons NO_X/yr) [b]	Emission reduction (tons VOC/yr) [b]	Cost effectiveness ($/ton)
Modified/Reconstructed	860,000	160,000	53	310	1,200	100,000

[a] Because of the heat content of recovered gas, each scf of recovered gas is assumed to offset one scf of natural gas; a value of $5/10,000 scf of natural gas was used to estimate recovery credit.

[b] These emission reductions are based on flares already meeting the short-term 162 ppmv H_2S fuel gas concentration limit in 40 CFR part 60, subpart J (*i.e.,* these are the incremental emission reductions achieved from a baseline of optimizing management of the fuel gas system to limit the short-term H_2S concentration in the fuel gas to 162 ppmv to the originally proposed combined short-term 162 ppmv H_2S concentration and long-term 60 ppmv H_2S concentration in the fuel gas).

Comment: Several commenters addressed the EPA's request for comment on ''the equivalency of the subpart Ja requirements as proposed to be amended today and the SCAQMD Rule 1118'' and ''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'' (73 FR 78532, December 22, 2008). One commenter disagreed with the EPA's position, alleging that ''EPA's suggestion that it can waive compliance with the NSPS in this manner is contrary to the Clean Air Act.'' The commenter stated that the EPA's suggestion ''that existing state and local requirements render the federal requirements irrelevant only confirms that EPA's proposed flaring requirements do not reflect the *best* technological system of continuous emission reduction.'' 42 U.S.C. 7411(h)(1) (emphasis added). The commenter also stated that the CAA already provides a mechanism for implementation of alternative work practice standards in narrowly defined circumstances (42 U.S.C. 7411(h)(3)); an owner or operator may demonstrate to the Administrator that an alternative means of emissions limitation is equivalent to the federal standard on a case-by-case basis. Therefore, the commenter asserted, the CAA clearly states that ''EPA's authority to waive federal work practice standards is case specific.'' Finally, the commenter stated that the EPA did not explain how emissions reductions achieved through compliance with SCAQMD Rule 1118 are equivalent to 40 CFR part 60, subpart Ja. Further, the commenter asserted that the EPA neither identified other state or local rules that could be considered equivalent to subpart Ja, nor explained how the EPA would determine that a specific state or local rule is equivalent to subpart Ja. Therefore, the commenter asserted, it is impossible to fully assess the merit of the EPA's idea and provide meaningful comments.

Another commenter stated that ''most stringent'' is not one of the criteria that must be applied under the law to determine BSER. Therefore, the commenter asserted, it is not appropriate to argue that the EPA did not properly determine BSER simply because there exist state or local rules that are more stringent than federal requirements. The commenter also asserted that the EPA has full authority to establish alternative regulatory standards that are determined to be as stringent as or more stringent than BSER, and CAA section 111(h)(3) generally applies after the EPA has completed a national rulemaking and an owner or operator requests approval for a site-specific alternative at a later date. The commenter asserted that it is logical that, if an alternative method is identified during the rulemaking process, ''the law would allow EPA to establish a site-specific alternative [in the rule itself] (especially, as under [CAA section 111], where the alternative would have to be determined through notice and comment rulemaking).''

Other commenters recommended that refineries complying with SCAQMD Rule 1118 be deemed in compliance with 40 CFR part 60, subparts J and Ja. According to one commenter, SCAQMD Rule 1118 is ''in all respects equivalent to or more stringent than the corresponding requirements'' of subparts J and Ja. Commenters also recommended that refineries should be able to consider compliance with BAAQMD Regulation 12, Rule 11 and Regulation 12, Rule 12 as compliance with the appropriate provisions of subpart Ja. One commenter provided a table comparing each of the six proposed flare management plan requirements in 40 CFR 60.103a(a) to the SCAQMD and BAAQMD regulations. The table identified sections of BAAQMD Regulation 12, Rule 11 and Regulation 12, Rule 12 that are equivalent to the six subpart Ja flare management plan requirements. The commenter also noted that SCAQMD Rule 1118 is only equivalent to five of the proposed requirements; it does not require an owner or operator to identify procedures to reduce flaring in cases of fuel gas imbalance (although another commenter noted that SCAQMD Rule 1118 requires minimization of all flaring, including fuel gas imbalance). While most commenters focused on the equivalence of the flare management plan requirements of the SCAQMD and BAAQMD rules and the flare management plan requirements of subpart Ja, one commenter requested that the periodic sampling of BAAQMD Regulation 12, Rule 11 be considered equivalent to the continuous sulfur monitoring requirements of subpart Ja for emergency flares.

Response: First, we note that there seems to be some misunderstanding regarding how a determination that SCAQMD Rule 1118 or BAAQMD Regulation 12, Rule 11 and Regulation 12, Rule 12 are equivalent to 40 CFR part 60, subpart Ja would actually be implemented in subpart Ja. The EPA will not ''waive'' the obligation to comply with subpart Ja if the source is complying with SCAQMD Rule 1118 or BAAQMD Regulation 12, Rule 11 and Regulation 12, Rule 12. In other words, the EPA will not allow the owner or operator to ''choose'' to comply with SCAQMD Rule 1118 or BAAQMD Regulation 12, Rule 11 and Regulation 12, Rule 12 instead of subpart Ja. Rather, the source must always demonstrate compliance with subpart Ja. If SCAQMD Rule 1118 or BAAQMD Regulation 12, Rule 11 and Regulation 12, Rule 12 are determined to be equivalent to subpart Ja, then these requirements would be provided as an alternative within subpart Ja for the source to demonstrate that it is meeting the requirements of subpart Ja.

To assess the comments, we reviewed SCAQMD Rule 1118, BAAQMD Regulation 12, Rule 11, and BAAQMD Regulation 12, Rule 12 and compared

these rules to the 40 CFR part 60, subpart Ja requirements we are finalizing here. We have included documentation of this review in Docket ID No. EPA–HQ–OAR–2007–0011 that shows the sections of each of those rules that we consider are equivalent to the subpart Ja requirements. We determined that SCAQMD Rule 1118 and BAAQMD Regulation 12, Rule 11 and Regulation 12, Rule 12 will result in equivalent to or greater than the emissions reductions resulting from the subpart Ja flare management plan requirements. As a result of our analysis, we have amended subpart Ja, as described in the following paragraphs.

We determined that SCAQMD Rule 1118 is equivalent to the flare requirements and monitoring, recordkeeping and reporting provisions for determining compliance with the flare requirements in 40 CFR part 60, subpart Ja. We also determined that the combined provisions of BAAQMD Regulation 12, Rule 11 and BAAQMD Regulation 12, Rule 12 are equivalent to the flare requirements and monitoring, recordkeeping and reporting provisions for determining compliance with the flare requirements in subpart Ja. Therefore, we have added specific compliance options for flares that are located in the SCAQMD and are in compliance with SCAQMD Rule 1118, as well as for flares that are located in the BAAQMD and are in compliance with both BAAQMD Regulation 12, Rule 11 and BAAQMD Regulation 12, Rule 12. Flares that are in compliance with these alternative compliance options are in compliance with the flare standards in subpart Ja. Specifically, 40 CFR 60.103a(g) specifies that flares that are located in the SCAQMD may elect to comply with SCAQMD Rule 1118 and flares that are located in the BAAQMD may elect to comply with both BAAQMD Regulation 12, Rule 11 and BAAQMD Regulation 12, Rule 12 to comply with the flare management plan requirements of 40 CFR 60.103a(a) and (b) and the root cause analysis and corrective action analysis requirements of 40 CFR 60.103a(c) through (e). In addition, 40 CFR 60.107a(h) indicates that flares that are located in the SCAQMD may elect to comply with the monitoring requirements of SCAQMD Rule 1118 and flares that are located in the BAAQMD may elect to comply with the combined monitoring requirements of both BAAQMD Regulation 12, Rule 11 and BAAQMD Regulation 12, Rule 12 to comply with the monitoring requirements of 40 CFR 60.107a(e) and (f). The owner or operator must notify the Administrator, as specified in 40 CFR 60.103a(g), that the flare is in compliance with SCAQMD Rule 1118 or both BAAQMD Regulation 12, Rule 11 and BAAQMD Regulation 12, Rule 12. The owner or operator must also submit a copy of the existing flare management plan (if applicable), as specified in 40 CFR 60.103a(g).

We note that, as pointed out by commenters, an owner or operator maintains the ability under CAA section 111(h)(3) to submit a request to establish, on a case-by-case basis, that "an alternative means of emission limitation will achieve a reduction in emissions * * * at least equivalent to the reduction in emissions" achieved under the flare standards of 40 CFR part 60, subpart Ja. Pursuant to CAA section 111(h)(3), we also included specific provisions within 40 CFR 60.103a for owners or operators to submit a request for "an alternative means of emission limitation" that will achieve a reduction in emissions at least equivalent to the reduction in emissions achieved under the final standards in subpart Ja.

Comment: Commenters suggested that the requirement to minimize discharges to the flare in 40 CFR 60.103a(a)(1) should specifically address routine discharges, and the EPA should limit the minimization requirements to actions that: (1) Are "consistent with good engineering practices" and (2) consider costs and other health and environmental impacts, as required by section 111 of the CAA.

Response: We agree that the language in proposed 40 CFR 60.103a(a)(1) appears to require an assessment of flare minimization irrespective of cost or other relevant considerations, as contained in CAA section 111, which was not our intent. We are clarifying, through this response, that cost, safety and emissions reductions may be considered when evaluating what actions should be taken to minimize discharges to a flare, but we disagree that the flare minimization assessment should be limited to "routine discharges." We have revised the flare management plan requirements in 40 CFR 60.103a(a) to more fully describe the types of information that must be evaluated and included in the plan.

As noted in the summary of this rule (section III.C of this preamble), we are finalizing our proposed withdrawal of the 250,000 scfd 30-day rolling average flow limit for flares. This limitation does not adequately account for site-specific factors regarding flare gas Btu content, ability to offset natural gas purchase and other considerations. We find that these factors need to be addressed in a site-specific basis and are more appropriately addressed through the flare management plan. In the absence of the specific flow limitation, we have included additional requirements in the flare management plan to prompt a thorough review of the flare system so that, as an example, flare gas recovery systems are installed and used where these systems are warranted. We have also revised the flare minimization requirements to require the flare management plans to be submitted to the Administrator (40 CFR 60.103a(b)).

As part of the development of the flare management plan, refinery owners and operators can provide rationale and supporting evidence regarding the flare reduction options considered, the costs of each option, the quantity of flare gas that would be recovered or prevented by the option, the Btu content of the flare gas and the ability or inability of the reduction option to offset natural gas purchases. The plan will also include the rationale for the selected reduction option, including consideration of safety concerns. The owner or operator must comply with the plan, as submitted to the Administrator. Major revisions to the plan, such as the addition of an alternative baseline (see next comment for further detail on baselines), must also be submitted to the Administrator.

In summary, although we did not incorporate the commenter's suggested language for limiting the scope of the minimization requirements to actions that are "consistent with good engineering practices" and that "consider costs and other health and environmental impacts," we acknowledge that these are valid considerations in the selection of the minimization alternatives available for a given affected flare. We find that the process of developing and submitting the flare management plan will ensure that these factors are considered consistent with CAA section 111 and that the requirement to minimize discharges to the flare is implemented consistently across all affected sources.

Comment: Commenters asserted that the flare flow root cause analysis threshold of 500,000 scf in any 24-hour period is arbitrary and cannot be fairly applied to all flares at all refineries. One commenter cited an ultracracker flare that routinely cycles from 5 million to 25 million scfd as an example of a flare for which the threshold of 500,000 scf in any 24-hour period would result in constant and meaningless root cause analyses. The commenters suggested removing the numerical threshold and limiting root cause analysis to upsets and malfunctions as initially promulgated in June 2008 (because root cause analysis is generally only effective

for reducing non-routine flows) or using a site- or flare-specific threshold instead. Even if the numerical threshold is revised, the commenters suggested that a number of streams be excluded from the calculation of flow, such as hydrogen and nitrogen, purge and sweep gas, natural gas added to increase the Btu content of the flare gas and gases regulated by other rules to avoid performing multiple root cause analyses for routine events. One commenter suggested that owners or operators should be able to use one root cause analysis report for an event that occurs routinely (as allowed in the consent decrees).

Response: We proposed the flare flow root cause analysis threshold of 500,000 scf in any 24-hour period because we projected that flare gas recovery would be a cost effective emission reduction technique for flares with fuel gas flows that routinely exceed 500,000 scfd, although we acknowledge that the threshold at which flare gas recovery becomes cost effective is strongly (inversely) correlated to the average Btu content of the flare gas (*i.e.,* a relatively small reduction in the Btu content of the gas makes the recovery system significantly less cost effective). Although we did not specifically exclude sweep or purge gas from the flow, we expected that the flow rates of sweep or purge gas (*i.e.,* gases needed to ensure the readiness of the flare and the safety of the flare gas system) would be negligible when compared to the root cause analysis threshold of 500,000 scf in any 24-hour period. In fact, in our original analysis of the appropriate flow rate root cause analysis threshold (Docket Item No. EPA–HQ–OAR–2007–0011–0246), we essentially assumed that the sweep and purge gas flow rates were zero, and we estimated costs and emissions reductions of the 500,000 scf in any 24-hour period threshold, based on recovering that amount of gas or eliminating recurring events of that size (rather than 500,000 scf minus the sweep or purge gas flow).

However, while we do not believe that 5 million scfd [10] is a reasonable base flow for a flare, we do acknowledge that the size of the flare, as well as the flare header system, will greatly impact the required flow needed to maintain the readiness of the flare. Although we can derive suitable flare flow thresholds for average conditions, these thresholds are not necessarily reasonable when applied to all flows, and we did not intend for on-going root cause analyses to be conducted on account of sweep or purge gas.

Therefore, rather than specifying a one-size-fits-all threshold, the final rule requires facilities to develop their own base flare flow rates as part of their flare management plan. A flow-based root cause analysis is triggered if flows measured by the flow monitor exceed 500,000 scf greater than the base flare flow rate in any 24-hour period. Evaluating the flow rate threshold above a baseline better reflects our original analysis of the impacts of flow-based root cause analyses when the sweep or purge gas flow rates are not negligible. We also note that 40 CFR 60.103a(d) allows a single root cause analysis to be conducted for any single continuous discharge that causes the flare to exceed either the root cause analysis threshold for SO_2 or flow for two or more consecutive 24-hour periods.

The final rule does not limit root cause analyses to upsets and malfunctions of refinery process units and ancillary equipment connected to the flare, nor does it explicitly allow owners or operators to use one root cause analysis report for an event that occurs routinely. When we decided to eliminate the numerical limit on flare flow rate, we specifically increased the scope of the flare flow root cause analysis to cover more than just upsets and malfunctions. We also decided not to explicitly allow owners or operators to use one root cause analysis report for an event that occurs routinely as a means to discourage routine flaring of recoverable gas. However, we recognize that there may be recurring discharges to the flare that are not recoverable for various reasons. Therefore, the final rule does allow for several base cases, which could include recurring maintenance; this provision will avoid multiple root cause analyses for a recurring event. As described above, the flare management plan (as well as significant revisions to the plan to include alternative baselines) must be submitted to the Administrator. The Administrator or delegated authority (*e.g.,* the state) may review the plan, although formal approval of the plan is not required. Not specifying a formal approval process is intended to minimize the burden associated with reviewing flare management plans. Rather, the rule specifies elements of the plan that need to be addressed in order for the plan to be considered adequate and provides an opportunity for a delegated authority to find the plan not adequate if they choose to do so.

We expect that a final flare management plan in compliance with 40 CFR part 60, subpart Ja will possess the following characteristics: (1) Completeness (all gas streams are considered, all required elements are included and all appropriate flare reduction measures are evaluated); (2) accuracy (the emission reductions and cost estimates for the different options are accurate); and (3) reasonableness (the selection of reduction options is correct and the baseline flow value is reasonable). If the Administrator identifies deficiencies in the plan (*e.g.,* the plan does not contain all the required elements, alternative flare reduction options were not evaluated or selected when reasonable, the baseline or alternative baseline flow rates are considered unreasonable), the Administrator will notify the owner or operator of the apparent deficiencies. The owner or operator must either revise the plan to address the deficiencies or provide additional information to document the reasonableness of the plan.

Comment: Commenters requested alternative monitoring options or an exemption from continuous flow monitoring for: (1) Flares designed to handle less than 500,000 scfd of gas; (2) pilot gas; (3) flares with flare gas recovery systems; (4) emergency flares; and (5) secondary flares. The commenters asserted that flow meters are costly and engineering calculations, which are currently used, are sufficient to evaluate when the flow to a flare exceeds 500,000 scf in any 24-hour period. One commenter stated that, for flares with flare gas recovery systems, the pressure drop across the flare seal drum can be used to calculate flow rate.

Response: In the final rule, flow monitoring is used to determine whether a root cause analysis is required rather than to ensure compliance with a specific flow limit. We have reviewed the commenters' suggestions and agree that, in certain specific cases, monitoring is not necessary and should not be required. However, as a general rule, we believe flow monitors are needed, not only to provide a verifiable measure of exceedances of the flow root cause analysis threshold, but also exceedances of the root cause analysis threshold of 500 lb SO_2 in any 24-hour period. In addition, when we evaluated local rules,

[10] Regarding commenter's cited ultracracker flare example, it is difficult to believe that sweep gas alone accounts for 5 million scfd of flare gas flow. Additionally, a compositional analysis of the base flare gas from the normal flow, based on data provided from a DIAL study of this refinery, suggests that the base flare gas is of sufficient quality to recover. It also appears, based on the data provided by the commenter, that the hydrogen stream recycle compressor was off-line approximately half the year. For such huge gas flows, considering the cost of purchasing or producing additional hydrogen and the emissions associated with that process, it is reasonable to expect that the facility would have a back-up compressor if the primary compressor is unreliable.

such as the initial BAAQMD rule for flare monitoring, we saw that the measured flare flow rates were several times greater than previously projected by the facilities.

Consequently, we find great value in the flow monitoring requirements for flares. These monitoring requirements will greatly improve the accuracy of emissions estimates from these flares. The resulting improved accuracy of flare emissions estimates will also lead to better decision-making as we conduct future reviews of rules applicable to petroleum refineries. We did consider each of the commenters' suggested exemptions in light of this fact; our specific considerations follow.

We did not specifically consider that some flares would not be capable of exceeding the flow root cause analysis threshold (*i.e.,* designed to handle less than 500,000 scfd of gas). However, these small flares could still exceed the root cause analysis threshold of 500 lb SO_2 in any 24-hour period. As such, we did not provide an exemption from the monitoring requirements for these small flares.

We agree that the monitoring of pilot gas flow is not needed. In the final rule, a root cause analysis is required if the gas flow to the flare exceeds 500,000 scf above the baseline in any 24-hour period. The flow of pilot gas is considered to be part of the baseline flow and is assumed to be constant. As such, monitoring of pilot gas would not be necessary to determine whether a flare has exceeded 500,000 scf above the baseline in any 24-hour period. In practice, the actual baseline flow set for the flare may or may not expressly include the pilot gas flow rate. Generally, the configuration of the flare header is such that the flare flow monitor would not measure pilot gas flow. In this case, the baseline flow determined for the flare would not expressly include the pilot gas flow rate. If the flare flow monitor is configured in such a way that it does measure pilot gas, then pilot gas would be considered part of the baseline conditions for that flare.

We agree with commenters that flares with flare gas recovery systems do have unique conditions and these warrant alternative monitoring options. Additionally, we recognize that the monitoring requirements may be burdensome for flares that are truly "emergency only" (*i.e.,* flares that flare gas rarely, if at all, during a typical year) or for secondary flares in a cascaded flare system. These flares are expected to have a water seal that prevents flare use during normal operations and ensures that the pressure upstream of the water seal (expressed in inches of water) does not exceed the water seal height during normal operations (hereafter referred to as "properly maintain a water seal"). We find that, for these select types of flares, water seal monitoring as an alternative to the flow (and sulfur) monitoring provisions is appropriate.

For flares with a flare gas recovery system and other emergency or secondary flares that properly maintain a water seal, the final rule states that an owner or operator may elect to monitor the pressure in the gas header just before the water seal and monitor the water seal liquid height to verify that the flare header pressure is less than the water seal, which is an indication that no flow of gas occurs. If the flare header pressure exceeds the water seal liquid level, a root cause analysis is triggered unless the pressure exceedance is attributable to staging of compressors. This alternative reduces the costs associated with installing sulfur and flow monitoring systems for flares that rarely receive fuel gas. Engineering calculations can be used to estimate the emissions during the event, but not for determining whether or not a root cause analysis is required.

To ensure that this option is only used for flares that are truly emergency flares and not for flares that are used for routine discharges, the final rule contains a limit on the number of pressure exceedances requiring root cause analyses that can occur in one year. Following the fifth reportable pressure exceedance in any consecutive 365 days, the owner or operator must comply with the sulfur and flow monitoring requirements of 40 CFR 60.107a(e) and (f). Based on a review of available flaring data, we expect that gas may be sent to an emergency flare three to four times per year, on average. Consistent with this information, we are providing in these final amendments that an "emergency flare" may receive up to four releases to the flare in any consecutive 365-day period to account for year-to-year variability. However, a flare receiving more than four discharges in a consecutive 365-day period can no longer be considered an "emergency flare" and must install the required sulfur and flow monitors.

Comment: Commenters requested an exemption from continuous sulfur monitoring or alternative monitoring options for flares handling only gases inherently low in sulfur content, emergency flares, flares with properly designed flare gas recovery systems and secondary flares. For flares handling gases low in sulfur, the commenters noted that continuous monitoring is unnecessary and certain fuel gas streams are already exempted from monitoring if they are combusted in a fuel gas combustion device. For flares that handle only gases exempt from the H_2S concentration requirements and flares with properly designed flare gas recovery systems, commenters stated that engineering calculations are sufficient to determine if the SO_2 root cause analysis threshold of 500 lb in any 24-hour period is exceeded. One commenter requested that the EPA allow owners or operators to submit and use an alternative monitoring plan to demonstrate that the flare gas recovery system is operating within its capacity and to calculate SO_2 emissions from engineering calculations and flare gas sampling. For secondary flares, one commenter noted that the continuous sulfur monitor on the primary flare could be used to determine the sulfur content of the gas being flared from the secondary flare.

One commenter requested that the EPA allow the use of engineering calculations to determine the sulfur-to-H_2S ratio because sampling can be difficult for emergency flares. One commenter noted that the EPA should allow the use of an existing continuous monitoring system if the gas sent to the flare is already monitored elsewhere. As examples, the commenter cited fuel gas and pilot gas already monitored within the fuel gas system.

For flares that rarely see flow, commenters particularly cited difficulties with performance tests. Commenters noted that, to meet the sulfur monitor performance test requirements, an owner or operator may have to intentionally flare gas that may not meet the H_2S concentration limits. One commenter also stated that performing the required relative accuracy test audit (RATA) could cause the flare to exceed the root cause analysis threshold. The commenter recommended revising the performance test requirements for flares with flare gas recovery to require only a cylinder gas audit.

Response: We have amended the final rule so that gases that are exempt from H_2S monitoring due to low sulfur content are also exempt from sulfur monitoring requirements for flares. For low-sulfur gases, the flare root cause analysis will always be triggered by an exceedance of the flow rate threshold well before the SO_2 threshold is exceeded, so no sulfur monitoring is required. However, this exemption can only be used for flares that are configured to receive only fuel gas streams that are inherently low in sulfur content, as described in 40 CFR

60.107a(a)(3), such as flares used for pressure relief of propane or butane product spheres (fuel gas streams meeting commercial grade product specifications for sulfur content of 30 ppmv or less) or flares used to combust fuel gas streams produced in process units that are intolerant to sulfur contamination (*e.g.,* hydrogen plant, catalytic reforming unit, isomerization unit or hydrogen fluoride alkylation unit). We already clarified that flare pilot gas is not required to be monitored. Also, 40 CFR part 60, subpart Ja already allows for H_2S monitoring at a central location, such as the fuel mix drum, for all fuel gas combustion devices (and we are finalizing amendments to ensure it is clear that H_2S monitoring at a central location is allowed for flares as well). Thus, we agree that if a flare only burns natural gas, fuel gas monitored elsewhere or fuel gas streams that are inherently low in sulfur content (as defined in 40 CFR 60.107a(a)(3)), then no H_2S monitor is needed.

The remaining issue is whether or not sulfur monitoring is necessary for ''emergency only'' flares. (An emergency flare is defined as a flare that combusts gas exclusively released as a result of malfunctions (and not startup, shutdown, routine operations or any other cause) on four or fewer occasions in a rolling 365-day period. For purposes of the rule, a flare cannot be categorized as an *emergency flare* unless it maintains a water seal.) We acknowledge that there are difficulties and costs with installing monitors on flares that rarely operate. However, we are concerned about how the owner or operator will detect emissions above 500 lb SO_2 in any 24-hour period during an upset or malfunction of a refinery process unit or ancillary equipment connected to the flare. Commenters appear to have conflicting opinions regarding the ability to sample the flare gas to determine the sulfur content (or total sulfur-to-H_2S ratio) during a flaring event. If samples could be taken during the flaring events, then that would be a potential option. However, during a process upset or malfunction, focus should be on alleviating the problem rather than taking a special sample. Also, given the duration of some of these events, it appears unlikely that representative samples can be manually collected.

Taking the difficulties discussed above into account, we have developed an alternative monitoring option for emergency flares. As noted in the previous response, emergency flares are expected to properly maintain a water seal. We provide pressure and water seal liquid level monitoring, as previously described as an alternative to the sulfur and flow monitors. As described in more detail above, any fuel gas pressure exceeding the water seal liquid level triggers a root cause analysis and there is a limit to the number of exceedances in one year. Under this option, a root cause analysis is triggered, based on the monitored pressure and water seal height, so accurate measurements of flow rate and sulfur concentrations are less critical than for flares that must evaluate these parameters to determine if a root cause analysis is needed. Consequently, for these flares, engineering calculations can be used to estimate the reported emissions during the flaring event, but the root cause analysis must be performed regardless of the magnitude of these engineering estimates. Using this alternative monitoring option, emergency flares are not required to install continuous sulfur monitoring systems. Flares that do not meet the conditions of an emergency flare are required to install continuous sulfur monitoring systems and cannot elect this alternative monitoring option.

We also agree that flaring solely for the purpose of a RATA or other performance test is not desirable. The ''cylinder gas audit'' procedures requested by the commenter are described as alternative relative accuracy procedures in section 16.0 of Performance Specification 2 (referenced from Performance Specification 5). We reviewed the alternative relative accuracy procedures and considered how they may apply to flares, and we have determined that the alternative relative accuracy procedures are appropriate for flares. We expect that, for most affected flares, the variability in flow (including no flow conditions) and sulfur content of the gases discharged to the flare create significant barriers to the normally required relative accuracy assessments, particularly if those assessments need to be made over a range of sulfur concentrations potentially seen by the monitor. Therefore, we are amending 40 CFR 60.107a(e)(1)(ii) and 40 CFR 60.107a(e)(2)(ii) to specify that the owner or operator of a flare may elect to use the alternative relative accuracy procedures in section 16.0 of Performance Specification 2 of Appendix B to part 60. As required by 40 CFR 60.108a(b), the owner or operator shall notify the Administrator of their intent to use the alternative relative accuracy procedures.

Comment: One commenter requested that the EPA clarify whether the additionally proposed sulfur monitoring options for flares are for total reduced sulfur or total sulfur. The commenter noted that measuring total sulfur is the simplest and most inclusive measurement of SO_2 emissions and it is the method included in SCAQMD Rule 1118. The commenter also requested that methods for measuring total sulfur in gaseous fuels be included as acceptable options to perform the relative accuracy evaluations of the CEMS.

One commenter requested that provisions be made in 40 CFR 60.107a(e)(2) to develop a total sulfur-to-H_2S (or total reduced sulfur-to-H_2S) ratio so that the total sulfur monitor can be used for both the root cause analysis requirements and for compliance with the requirement to limit short-term H_2S concentration in fuel gas sent to a flare to 162 ppmv without the need for a duplicative continuous H_2S monitor. Another commenter supported the addition of alternative monitoring methods for the sulfur content of flare gas, but noted that since the composition of flare gas is highly variable, the alternative methods must meet continuous monitoring requirements.

Response: We have clarified and consolidated the monitoring requirements to allow total reduced sulfur monitoring for flares. For the purposes of evaluating the SO_2 root cause analysis threshold, total sulfur monitoring provides the most accurate assessment. However, in most cases, the vast majority of sulfur contained in gases discharged to the flare is expected to be in the form of total reduced sulfur compounds, which include carbon disulfide, carbonyl sulfide and H_2S. Our test method for measuring total reduced sulfur includes the use of EPA Method 15A as a reference method, and because EPA Method 15A measures total sulfur, the total reduced sulfur monitoring requirement is equivalent to a total sulfur monitoring method.

As discussed previously, we are relying on the suite of flare requirements we are promulgating to limit SO_2 emissions at the flare. These include optimizing management of the fuel gas by limiting the short-term concentration of H_2S to 162 ppmv during normal operating conditions. We expected most refineries would already have the H_2S monitor and did not consider the use of a total sulfur monitor for use in complying with the short-term 162 ppmv H_2S concentration in the fuel gas. As the H_2S concentration will always be less than the total reduced sulfur concentration, it is acceptable to use the total reduced sulfur monitor to verify that the fuel gas

does not exceed the short-term H_2S concentration of 162 ppmv. Therefore, we have provided for the use of total reduced sulfur monitors, provided the monitor can also meet the 300 ppmv span requirement.

However, we have not provided a correction factor to scale down the total reduced sulfur concentration to H_2S. The owner or operator using this method must essentially be able to demonstrate they can achieve a 162 ppmv total reduced sulfur concentration in the fuel gas. The concentration ratio was provided for the purposes of the root cause analysis because of the costs of adding a total sulfur monitoring system when a dual range H_2S monitor was already in-place, as well as the expected accuracy needed for the system to assess the SO_2 root cause analysis threshold. As few cases would exist where the flaring event would be right at the SO_2 root cause analysis threshold of 500 lb in any 24-hour period, inaccuracies associated with the average total sulfur-to-H_2S ratio were not expected to be significant.

On the other hand, the short-term 162 ppmv H_2S concentration in the fuel gas must be continuously maintained, and the total sulfur-to-H_2S ratio at these low concentrations is expected to be highly variable, depending on the efficiency of the amine scrubber systems. As the amine scrubber systems, according to previous industry comments, are not effective for reduced sulfur compounds other than H_2S, the non-H_2S reduced sulfur concentration is expected to be fairly constant, with most of the fluctuations in total sulfur content being attributable to fluctuations in H_2S concentrations. Consequently, we have determined that the inaccuracies of the ratio approach are not acceptable for continuously demonstrating that the short-term concentration in the fuel gas does not exceed 162 ppmv H_2S. Therefore, owners or operators of affected flares may use the direct output of a total reduced sulfur monitor to assess compliance with the short-term 162 ppmv H_2S concentration in the fuel gas, or they must install a continuous H_2S monitor.

Comment: One commenter supported the proposed amendment revising the span value for fuel gas H_2S analyzers to match the span requirements in 40 CFR part 60, subpart J, stating this will save time and money. However, the commenter stated that the span value for the flare H_2S monitoring option is too restrictive and suggested that requirements in Appendix F to part 60 provide sufficient quality assurance/quality control (QA/QC) without the need for the rule to specify the span range. The commenter also requested clarification of the sulfur monitor span for flares, suggesting that it should be based on the H_2S concentration limits and that engineering calculations can be used to assess exceedances of the SO_2 root cause analysis threshold of 500 lb in any 24-hour period.

Response: The H_2S span value is at 300 ppmv to verify compliance with the H_2S concentration requirement for the fuel gas; the span of the total sulfur monitor needs to be much greater than that to be able to quantify the sulfur content in streams containing several percent sulfur. For units that use the H_2S analyzers both to assess compliance with the short-term 162 ppmv H_2S concentration requirement for the fuel gas and to assess exceedances of the SO_2 root cause analysis threshold of 500 lb in any 24-hour period, a dual range monitor will be necessary. For the purposes of the SO_2 root cause analysis threshold of 500 lb in any 24-hour period, we intended that the monitor be capable of accurately determining the sulfur concentration for the range of concentrations expected to be seen at the flare. We are particularly interested in quantifying the concentrations of high sulfur-containing streams as these would be the streams most likely to trigger a root-cause analysis at low flows. We proposed that the span for the flare sulfur monitor be selected from a range of 1 to 5 percent. We agree with the commenter that this may be too restrictive, and we have revised the span requirements to be determined, based on the maximum sulfur content of gas that can be discharged to the flare (*e.g.,* roughly 1.1 to 1.3 times the maximum anticipated sulfur concentration), but no less than 5,000 ppmv. A single dual range monitor may be used to comply with the short-term 162 ppmv H_2S concentration requirement for the fuel gas and the SO_2 root cause analysis threshold monitoring requirement provided the applicable span specifications are met. In reviewing the span specifications, we noted that span requirements were inadvertently omitted from the total reduced sulfur compound monitoring alternative. The purpose of these monitors is identical to the H_2S monitoring alternative, and the same span considerations apply for these monitors.

We disagree that the QA/QC procedures in Appendix F to part 60 are sufficient without specifying the span values. Procedure 1 of Appendix F to part 60 defines ''span value'' as: ''The upper limit of a gas concentration measurement range that is specified for affected source categories in the applicable subpart of the regulation.'' The concentrations used for calibration are based on the span value. Several of the QA/QC procedures in Appendix F are undefined if the span value is not defined in the rule.

Comment: Commenters stated that time is needed to install continuous monitors and to make other necessary changes (such as installing a flare gas recovery system or additional amine treatment) to comply with all the flare requirements (*e.g.,* limiting short-term H_2S concentration to 162 ppmv, long-term 60 ppmv H_2S fuel gas concentration limit, flare management plan, root cause analysis and continuous monitoring), especially considering how quickly a flare may become a modified affected source. While most commenters focused on the amount of time needed to install equipment to comply with the long-term 60 ppmv H_2S fuel gas concentration limit, other commenters asserted that additional time for activities, such as planning and re-piping, would be needed to meet the standards. Commenters requested differing amounts of additional time generally ranging from 3 to 5 years. Commenters noted that the additional time would allow owners and operators to schedule any process unit shutdowns needed to install new equipment or monitors during a turnaround. One commenter recommended that the extra time to begin root cause analyses provided to refiners committing to install flare gas recovery systems should also be provided to refiners committing to expand an existing flare gas recovery system. Commenters also noted that experience implementing SCAQMD Rule 1118 suggests that there will be difficulty obtaining and installing continuous monitors in less than 3 years due to the availability of monitor manufacturers and the need to stage the installation of monitors at refineries with multiple affected flares. One commenter requested that the EPA consider a compliance schedule in 40 CFR part 60, subpart Ja that is consistent with compliance schedules in consent decrees. Commenters objected to phasing out the additional time after the rule has been in place for 5 years.

One commenter requested clarification regarding the trigger date from which the additional time to comply with the flare provisions (*e.g.,* 2 years when installing a flare gas recovery system) begins. The commenter questioned whether the trigger date is when construction starts, at startup or when the stay is removed (or whichever is later). Another commenter agreed that the EPA should

set the compliance time based on the initial startup of the modification. The commenter noted that the EPA should follow the 40 CFR part 60 General Provisions for performance test timing and the 40 CFR part 63 General Provisions for compliance timing.

Response: As we are no longer applying the long-term 60 ppmv H_2S fuel gas concentration limit to flares, the comments related to the amount of time needed to comply with a long-term 60 ppmv H_2S fuel gas concentration limit are moot. We do, however, recognize that a flare modification can occur much more quickly than modifications of traditional process-related emission sources. Therefore, we evaluated the comments regarding the amount of time needed to meet the various requirements for flares while keeping the 40 CFR part 60, subpart Ja flare modification provision in mind. We discuss each requirement and the time for demonstrating compliance with that requirement in the following paragraphs.

We find it appropriate to require modified flares that already have adequate treatment and monitoring equipment in place to achieve a short-term H_2S concentration of 162 ppmv (resulting from compliance with 40 CFR part 60, subpart J) to continue to meet that concentration upon startup of the affected flare or the effective date of this final rule, whichever is later. However, some flares are not affected facilities subject to 40 CFR part 60, subpart J, and others are complying with subpart J requirements as specified in consent decrees or have received alternative monitoring plans by which to demonstrate compliance with the short-term H_2S concentration limit. In these cases, we find it appropriate to allow more time to comply with the short-term H_2S concentration limit and/or the associated monitoring requirements because additional amine treatment and/or monitoring systems will be required to comply with the rule.

Therefore, the final rule requires all modified flares that are newly subject to 40 CFR part 60, subpart Ja (but were not previously subject to 40 CFR part 60, subpart J) to comply with the short-term H_2S concentration limit and applicable monitoring requirements no later than 3 years after the effective date of this final rule or upon startup of the affected flare, whichever is later. Modified flares that have accepted applicability of subpart J under a federal consent decree shall comply with the subpart J requirements as specified in the consent decree but shall comply with the short-term H_2S concentration limit and applicable monitoring requirements no later than 3 years after the effective date of this final rule. Modified flares that are already subject to the 162 ppmv short-term H_2S concentration limit under subpart J must meet the short-term H_2S concentration limit under subpart Ja upon startup of the affected flare or the effective date of this final rule, whichever is later. Finally, modified flares that are already subject to the short-term H_2S concentration limit but that have an approved monitoring alternative under subpart J and do not have the monitoring equipment in-place that is required under subpart Ja shall be given up to 3 years from the effective date of this final rule to install the monitors required by subpart Ja (or to obtain an approved monitoring alternative under subpart Ja).

As we noted in the preamble to the proposed amendments, 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. At the same time, nearly all refineries will need time for planning, designing, purchasing and installing (including any necessary re-piping) sulfur and flow monitors that are newly required by subpart Ja. Some refineries will elect to add flare gas recovery and/or sulfur treatment equipment to minimize their emissions as part of the evaluations conducted, as required by the new flare management plan requirements, and time will be needed for planning, designing, purchasing and installing these components as well. Given that many flares will become modified affected sources relatively quickly, owners and operators will be competing with one another for the services and products of a finite number of vendors who provide the necessary monitors and other equipment. Several commenters specifically noted availability of monitors as an issue when complying with SCAQMD Rule 1118. As such, we find that immediate compliance with the requirements for flares, such as the planning, designing, purchasing and installation of (including any necessary re-piping) sulfur and flow monitors, may be difficult for operators to meet, especially in situations where quick connections to the flare are made. A phased compliance schedule allows for the operators to comply with some requirements associated with flares, such as continuing to achieve a short-term H_2S concentration of 162 ppmv, if the flares are already subject to 40 CFR part 60, subpart J and have adequate monitoring in place to comply with this final rule, while allowing time to install treatment and processing equipment and monitoring equipment to comply with the standards where necessary.

A phased compliance schedule will also allow owners and operators to minimize process interruption by coordinating the installation of monitoring equipment with process shutdowns or turnarounds. In addition to providing operating flexibility to the refinery, we are taking into consideration the fact that a process shutdown and subsequent startup can generate significant emissions, even if the refinery is taking care to minimize those emissions. We consider a phased compliance schedule that allows owners and operators to avoid startups and shutdowns that are not necessary to maintain the equipment and process to be environmentally beneficial overall and the best system of emissions reduction for a quickly modified flare. Considering the time needed to complete engineering specifications, order and install the required monitoring equipment, and considering the need to coordinate this installation with process unit shutdown or turnarounds, we determined that completion of these activities within 3 years is consistent with the best system of emissions reductions for quickly modified flares.

We note, however, that this phased compliance schedule for the flare requirements in 40 CFR part 60, subpart Ja is intended for those situations when a flare modification occurs quickly and the owner or operator does not have significant planning opportunities to install the required monitors or implement the selected flare minimization options without significant process interruptions. For a future large project on a schedule that includes time for planning, designing, purchasing and installing equipment and monitors, we expect that the owner and operator will have time to assess whether or not the refinery flares will become affected sources through modification. If a project will result in the modification of a flare, we expect that the owner or operator will then plan how to meet the standards in subpart Ja as part of the project itself, including the installation of the monitoring systems and the development of a flare management plan. Because of the ability to plan ahead, flares that are modified as part of a large project will not have all of the difficulties meeting the subpart Ja flare requirements upon completion of the modification as those flares that are modified quickly. Therefore, we find that compliance with the flare

requirements upon startup of the modified flare is appropriate and consistent with the best system of emissions reduction for large projects resulting in a modification of a flare. Thus, we determined that the appropriate time period for compliance with the flare standards is either: (1) 3 years from the effective date of these amendments or (2) upon startup of the modified flare, whichever is later.[11] In this manner, flares that become subject to subpart Ja quickly, based on a small safety-related connection (or have already become subject to subpart Ja based on a modification prior to the effective date of these amendments), will have up to 3 years from the effective date of these amendments to comply fully with the flare standards, but flares that are modified as the result of a significant project, such as the installation of a new process unit that will be tied into an existing flare, will effectively be required to comply with the flare standards at the startup of the new process unit.

Therefore, for the reasons described above, we are providing flares that become affected facilities subject to 40 CFR part 60, subpart Ja through modification with a phased compliance schedule for the flare standards, as described in this paragraph. The final rule requires owners and operators of modified flares to meet the short-term 162 ppmv H_2S concentration requirement by the effective date of these amendments or upon startup of the affected flare (whichever is later) only if they are already subject to the short-term 162 ppmv H_2S concentration limit in 40 CFR part 60, subpart J. Modified flares that were not affected flares under subpart J prior to being modified facilities under subpart Ja must comply with the short-term 162 ppmv H_2S concentration requirement within 3 years of the effective date of these amendments or upon startup of the modified flare, whichever is later. Owners and operators of modified flares that are have accepted applicability of subpart J under a federal consent decree shall comply with the subpart J requirements as specified in the consent decree, but must meet the short-term 162 ppmv H_2S concentration limit no later than 3 years after the effective date of this final rule. Owners and operators of modified flares that are already subject to subpart J and that have an approved monitoring alternative and are unable to meet the applicable subpart Ja monitoring requirements for the short-term H_2S concentration limit must meet the short-term H_2S concentration requirement upon startup of the affected flare or the effective date of this final rule, whichever is later, but shall be given up to 3 years from the effective date of this final rule to install the monitors required by subpart Ja. In this interim period, owners and operators of these modified flares shall demonstrate compliance with the short-term H_2S concentration limit using the monitoring alternative approved under subpart J.

Additionally, we are requiring owners and operators of modified flares to complete and implement the flare management plan under 40 CFR 60.103a(a) by 3 years from the effective date of these amendments or upon startup of the modified flare, whichever is later. We are requiring owners and operators of modified flares to begin conducting root cause and corrective action analyses under 40 CFR 60.103a(c) and (d) no later than 3 years from the effective date of these amendments or the date of the startup of the modified flare, whichever is later, so that the facility can complete the flare management plan and establish baseline flow rates prior to performing the root cause and corrective action analyses. We are also requiring owners and operators of modified flares to install and begin operating the monitors necessary to demonstrate compliance with these provisions, as required under 40 CFR 60.107a(e) through (g) within 3 years from the effective date of these amendments or by the startup date of the modified flare, whichever is later, when the monitors are not already in place. Compliance with the phased compliance schedule constitutes compliance with the flare standards as of the effective date.

We note that the final rule does not provide a phased compliance schedule for new and reconstructed flares. The final rule requires owners and operators of new and reconstructed flares to meet all the flare requirements, including the short-term 162 ppmv H_2S concentration requirement, upon the effective date of the requirements or upon startup of the affected flare, whichever is later.

C. Other Comments

Comment: Several commenters objected to the change to the definition of ''refinery process unit.'' The commenters objected to the proposed amendments to include coke gasification, loading and wastewater treatment, stating the change makes the term more expansive. The commenters stated that the EPA did not evaluate the impacts or explain the consequences of the revised definition. One commenter stated that product loading is generally considered part of the refinery process unit to which it is associated and that wastewater treatment is a utility. Another commenter suggested that the definition specify SIC 2911 (as in Refinery MACT 1).

Response: The original definition of ''refinery process unit'' in 40 CFR part 60, subpart J and the definition of ''refinery process unit'' promulgated in 40 CFR part 60, subpart Ja in June 2008 read as follows: ''Refinery process unit means any segment of the petroleum refinery in which a specific processing operation is conducted.'' Thus, to be considered a refinery process unit, only two criteria are needed: (1) The unit must be located at a petroleum refinery; and (2) the unit must be used to conduct ''a specific processing operation.'' The definition does not directly limit the scope of ''processing operations.'' That is, the definition of refinery process unit does not limit process operations to distillation, re-distillation, cracking or reforming, and it is not limited to only those processes used to produce gasoline, kerosene, fuel oils, etc. In the proposed amendment to this definition, we listed ''operations'' that we construed as conducting a ''specific processing operation'' when these operations are located at a petroleum refinery. Consequently, we considered the proposed inclusion of examples of refinery process units to be a clarification of the existing definition rather than an expansion of the original definition.

We reviewed the impact of the proposed revision of this definition on 40 CFR part 60, subpart Ja, as well as its historic use in 40 CFR part 60, subpart J. The term ''refinery process unit'' is used primarily in the definitions of certain affected facilities, ''process gas'' and ''process upset gas'' in subparts J and Ja. The term is also used in the flare provisions in subpart Ja. With respect to the definitional terms, there can be no issue with including the designation of ''refinery process unit'' within the definitions for specific process units. ''Process gas'' is not used at all in either rule, although it was revised between proposal and promulgation of subpart J. In response to a comment that the definition of ''process gas'' ''should have included the non-hydrocarbon gases produced by various process units in a refinery,'' the EPA responded: ''The definition has been revised to include all gases produced by process units in a refinery except fuel gas and process upset gas.'' (See page 127 of *Background*

[11] For the purposes of this subpart, startup of the modified flare occurs when any of the activities in 40 CFR 60.100a(c)(1) or (2) is completed (*e.g.*, when a new connection is made to a flare such that flow from a refinery process unit or ancillary equipment can flow to the flare via that new connection).

Information for New Source Performance Standards, Volume 3, Promulgated Standards (BID Vol. 3), EPA 450/2–74–003 (Feb. 1974), Docket Item No. EPA–HQ–OAR–2007–0011–0082). The definition had actually been revised to include "any gas generated by a petroleum refinery process unit." The response in BID Vol. 3 suggests that the EPA considered "refinery process units" and "process units in a refinery" to have the same meaning, and there is no mention of limiting what is considered to be a "refinery process unit" or a "process units in a refinery."

"Process upset gas" is used only to provide an exemption to the H_2S concentration limit for process upset gas sent to a flare. See 40 CFR 60.104(a)(1), 60.103a(h). Therefore, a narrow definition of "refinery process unit" would only limit those gases sent to a flare that would qualify as "process upset gas." For example, if a coke gasifier is not a refinery process unit, then gases generated during the startup, shutdown or malfunction of a coke gasifier located at the refinery would not be "process upset gas" and would be required to comply with the requirement to limit short-term H_2S concentration in fuel gas to 162 ppmv if sent to a flare. We find that the historical application of the "process upset gas" exclusion has considered a broad definition of what constitutes a "refinery process unit."

For 40 CFR part 60, subpart Ja, the definition of "refinery process unit" also impacts the flare provisions. Based on the proposed revisions of "refinery process unit," it was clearly our intent that a broad definition of "refinery process unit" should apply to the flare requirements. Specifically, we intended that a flare modification occurs when a wide range of equipment at the petroleum refinery is newly connected to the flare. It was also our intent that the flare management plan consider flare minimization methods for this broadly defined range of equipment referred to collectively as "refinery process units."

Based on our review of the impacts of changes to the definition of "refinery process unit," and considering all of the comments received, we maintain that the existing definition of "refinery process unit" is broad and should be broadly interpreted. For consistency between 40 CFR part 60, subparts J and Ja, we have elected to maintain the existing definition and not include an example list of refinery process units within the definition. However, to clarify that a modification to a flare occurs when these types of equipment are connected to the flare, we revised the language in the flaring provisions to refer to "refinery process units, including ancillary equipment." This revision is made to clarify our original intent that coke gasification units, storage tanks, product loading operations and wastewater treatment systems, as well as pressure relief valves, pumps, sampling vents, continuous analyzer vents and other similar equipment are units from which a connection to a flare would trigger a flare modification and generate gas streams that should be considered in the flare management plan. We have included in the final amendments a definition of "ancillary equipment." Specifically, *ancillary equipment* means equipment used in conjunction with or that serve a refinery process unit. *Ancillary equipment* includes, but is not limited to, storage tanks, product loading operations, wastewater treatment systems, steam- or electricity-producing units (including coke gasification units), pressure relief valves, pumps, sampling vents, and continuous analyzer vents.

Sulfur recovery plants are also units from which a connection to a flare would trigger a flare modification and generate gas streams that should be considered in the flare management plan. We recognize that on-site sulfur recovery plants are considered refinery process units, and we proposed amendments to the definitions of "refinery process unit" and "sulfur recovery plant" to clarify that we consider a sulfur recovery plant to be "a segment of the petroleum refinery in which a specific processing operation is conducted." However, the strict definition of "refinery process unit" would only apply to sulfur recovery plants physically located at the refinery. As 40 CFR part 60, subpart Ja also applies to off-site sulfur recovery plants (see 40 CFR 60.100(a) and 40 CFR 60.100a(a)), we found it potentially contradictory to define a sulfur recovery plant located outside the refinery as a "refinery process unit," so we are also not finalizing the proposed amendment to include the term "all refinery process units" in the definition of "sulfur recovery plant." However, while connections to a refinery flare from an off-site sulfur recovery plant are not expected to be common, off-site sulfur recovery plants are subject to subpart Ja. We clarify in this response that we would consider such a connection to a flare to be from a "refinery process unit, including ancillary equipment," such that connecting an off-site sulfur recovery plant that is subject to subpart Ja to a flare at a refinery would cause that flare to be a modified flare subject to subpart Ja.

Further, in reviewing the definition of "sulfur recovery plant," we noticed an inadvertent error that also suggests that the sulfur recovery plant must be located at a petroleum refinery, which is not consistent with the applicability provisions in 40 CFR 60.100(a) and 40 CFR 60.100a(a). Specifically, we inadvertently omitted the word "produced" in this first sentence, so we are amending the definition of "sulfur recovery plant" to clarify that a sulfur recovery plant recovers sulfur from sour gases "produced at the petroleum refinery." Thus, we are amending the definition of "sulfur recovery plant" to correct inadvertent errors and to clarify that off-site sulfur recovery plants are included in the definition of "sulfur recovery plant," as these plants are expressly considered to be affected facilities in 40 CFR part 60, subpart Ja.

Comment: Commenters supported the revised definition of "delayed coking unit," but stated that, since 40 CFR part 60, subpart Ja only sets standards for the coke drums, the definition should just include the coke drums associated with a single fractionator. The commenters stated that the definition should not include the fractionator itself because VOC emissions from the fractionator are covered by NSPS for equipment leaks.

Response: The proposed amendments to the definition of "delayed coking unit" specifically listed the primary components of the delayed coking unit. In particular, based on the operation of the delayed coking unit, we find that the fractionator is an integral part of the delayed coking unit. The fresh feed to the delayed coking unit is generally introduced in the fractionator tower bottoms receiver. This integral use of the fractionator is different than the use of fractionators used for other units defined in 40 CFR part 60, subpart Ja, such as the fluid catalytic cracking unit (FCCU). For the FCCU, fresh feed is introduced in the riser, which is part of the affected facility in subpart Ja. As the feed to the delayed coking unit is to the fractionator, we find that the fractionator is an integral part of the delayed coking unit, so we specifically include it as part of the affected facility. While our proposed amendments covered only the major components of the delayed coking unit, upon our review of the definition based on the comments received, we note that there are several other components of the delayed coking unit that are integral to the operation of the delayed coking unit. Additionally, even though the standards are specific to the coke drum, many of these integral components are

interconnected and necessary for the delayed coking unit to meet the applicable standards. Based on our review of the operation of a delayed coking unit, we also include coke cutting and blowdown recovery equipment in the final definition because this equipment is also integral to the overall cyclical operation of the process unit. The definition of ''delayed coking unit'' has been amended in the final rule to mean 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'' includes, but is not limited to all of the coke drums associated with a single fractionator; the fractionator, including bottoms receiver and overhead condenser; the coke drum cutting water and quench system, including the jet pump and coker quench water tank; process piping and associated equipment such as pumps, valves and connectors; and the coke drum blowdown recovery compressor system.

Since this definition is more specific than the definition included in the amendments proposed on December 22, 2008, it could affect which delayed coking units are subject to subpart Ja. For example, an owner or operator may have made a change to a delayed coking unit that would not be considered a modification under the December 22, 2008, definition, but that same change could make the delayed coking unit a modified facility subject to subpart Ja using the definition of ''delayed coking unit'' above. In other words, in changing the definition of ''delayed coking unit'' in the final rule, some delayed coking units that would not have been affected sources under the proposed requirements might now be covered by the final rule. Under CAA section 111(a)(2), a ''new source'' is defined from the date of proposal only if there is a standard ''which will be applicable to such source;'' otherwise, a ''new source'' is defined based upon the final rule date. In this circumstance, using the proposal date as the new source date for determining applicability for this group of delayed coking units would be inappropriate as such units would not have been on notice that subpart Ja could apply to them. Accordingly, we moved the ''new source'' date for this group of delayed coking units so that delayed coking units that are only defined as such under the final rule are covered by the final rule only if they commence construction, reconstruction or modification after the promulgation date of these final amendments. The ''new source'' date for other delayed coking units will depend on the previous definitions and when the activities involving the delayed coking unit occurred. See § 60.100a(b) for determining applicability of subpart Ja for delayed coking units.

Comment: One commenter stated that 40 CFR part 63, subpart LLLLL indicates at 40 CFR 63.8681(e) that 40 CFR part 60, subpart J does not apply for asphalt blowing stills subject to subpart LLLLL, and the commenter requested similar clarification for 40 CFR part 60, subpart Ja by exempting this process in 40 CFR 60.100a.

Response: We reviewed the requirement in 40 CFR part 63, subpart LLLLL. Due to the O_2 content of this process gas, we agree that it is not suitable for recovery as fuel gas and subsequent amine treatment; therefore, it is not BSER for combustion controls used on asphalt blowing stills to meet the H_2S concentration limits (or alternative SO_2 emissions limits). We reviewed 40 CFR 60.100a, but we feel a blanket exemption from 40 CFR part 60, subpart Ja is not necessary. Instead, we have included an exemption within the definition of fuel gas similar to the exemptions included for combustion controls on vapors collected and combusted from wastewater treatment and marine vessel loading operations. Specifically, we amended the definition of fuel gas in 40 CFR 60.101a to clarify that fuel gas does not include vapors that are collected and combusted to control emissions from asphalt processing units (*i.e.,* asphalt blowing stills).

Comment: One commenter recommended that the exclusion from the definition of ''fuel gas'' be extended to vapors ''from marine vessel loading operations or waste management units that are collected and combusted'' without any reference to a federal requirement. At a minimum, the commenter stated that marine benzene loading under 40 CFR part 61, subpart BB; the wastewater provisions of 40 CFR part 63, subpart G; remediation efforts regulated under Resource Conservation and Recovery Act (RCRA) corrective action; and RCRA 7003 orders should be added to the exclusion.

Response: We were originally concerned that removing the reference to a federal standard may inadvertently exempt the use of these vapors when used in process heaters or boilers. We determined that it was not BSER to require thermal oxidizers used to comply with the cited federal standards to comply with the H_2S concentration limits due to the typically remote location of the combustion sources (control devices) relative to refinery process units (see technical memorandum entitled *Fuel Gas Treatment of Marine Vessel Loading and Wastewater Treatment Unit Off-gas,* in Docket ID No. EPA–HQ–OAR–2007–0011). However, if these gases are currently routed to a fuel gas system or directly to a process heater or boiler, treatment of the fuel gas to meet the SO_2 emissions limits or the H_2S concentration limits is expected to be economically viable. Additionally, these gases are expected to be only a small portion of the fuel gas combusted in these units, and the refinery has an option to over-treat the primary fuel gas so that gases from the wastewater treatment system or marine vessel loading operation can remain untreated while the fuel gas combustion device itself can comply with the SO_2 emissions limits or the H_2S concentration limits, based on the mixture of fuels used in the device.

In reviewing the rules suggested by the commenter, as well as those we originally listed, we noted that acceptable ''control devices'' or ''combustion units'' in these rules include process heaters and boilers. We did not intend to exclude vapors that are collected and routed to a process heater or boiler to be exempt from the definition of fuel gas. In other words, when developing this exclusion, we specifically considered the combustion of these gases via a thermal oxidizer or flare currently located at the marine vessel loading or wastewater treatment location. These remote combustion devices were really the subject of the analysis, but we did not want to exclude these combustion units themselves because other fuel gas is often fed to these units to ensure adequate combustion of the vapors being controlled. It is clear from our rationale and the description of the exemption included in the preamble of the proposed rule that the exemption was intended ''to exempt vapors that are collected and combusted in an air pollution control device installed to comply with'' specific wastewater or marine vessel loading emissions standards. (72 FR 27180 and also at 27183) Process heaters or boilers would not be ''installed'' to comply with these provisions, and it was not our intent to exclude vapors sent to these types of combustion units. However, the regulatory text is more ambiguous and appears to exclude any vapors collected and combusted, regardless of where they are combusted. As such, we are amending this exclusion to better represent our original intent.

Additionally, with the added clarity in the regulatory text, it seems appropriate to extend this exclusion to control devices used at these locations regardless of why the emission controls were installed. That is, while we originally considered air pollution control devices that were mandated by the EPA, we see no reason to discriminate against air pollution control devices that were installed voluntarily to reduce the emissions from these sources. Further, we intend to clarify that gases off the sour water system, including the sour water stripper, would likely contain higher amounts of reduced sulfur and would be economically viable to treat. Therefore, we are also clarifying that the exemption does not extend to the sour water system. Therefore, the amended definition of "fuel gas" in both 40 CFR part 60, subparts J and Ja states that fuel gas "does not include vapors that are collected and combusted in a thermal oxidizer or flare installed to control emissions from wastewater treatment units other than those processing sour water, marine tank vessel loading operations, or asphalt processing units (*i.e.,* asphalt blowing stills)."

With respect to remediation efforts conducted under RCRA corrective actions, we are unwilling to grant such an exclusion from the definition of "fuel gas" in 40 CFR part 60, subpart Ja. First, we anticipate that most vapors from remediation efforts would be low in sulfur and, if so, the owner or operator could apply for the alternative monitoring methods provided in the rule. Also, although some remediation efforts may occur in remote locations, many of the remediation efforts are conducted in reasonable proximity to existing process units. Finally, the range of activities included in RCRA remediation efforts is broad, and we have little information regarding the number and types of RCRA remediation activities that are being conducted. The commenter provided no description of such activities, nor did they provide a reasonable rationale as to why the vapors from these activities should be exempted.

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

A. What are the emission reduction and cost impacts for the final amendments?

The emission reduction and cost impacts presented in this section for flares are revised estimates for the impacts of the final requirements of 40 CFR part 60, subpart Ja for flares, as amended by this action. The table shows the differences in anticipated impacts between these final amendments to subpart Ja and the final June 2008 NSPS requirements of subpart Ja, which were estimated assuming only 40 flares would trigger applicability to the rule. The impacts are presented for 400 affected flares that commence construction, reconstruction or modification that will be required to comply with this final rule. We anticipate that most of the flares would become affected due to the modification provisions for flares set forth in the final June 2008 subpart Ja rule. For this analysis, we assumed that 90 percent of the flares will be modified or reconstructed and 10 percent of the flares will be newly constructed. Further, we estimate that 30 percent of the 400 affected flares, or 120 flares, either would meet the definition of "emergency flare" in subpart Ja or would be equipped with a flare gas recovery system such that robust sulfur and flow monitoring would not be required. Therefore, the values in Table 5 of this preamble include the costs and emissions reductions for 400 flares to comply with the flare management plan and root cause and corrective action analyses requirements and for 280 flares to comply with the sulfur and flow monitoring requirements. The cost and emissions reductions for the affected flares to comply with the short-term H_2S concentration of 162 ppmv in the fuel gas are included in the baseline rather than the incremental impacts because this limit is unchanged from the requirements in 40 CFR part 60, subpart J. For further detail on the methodology of these calculations, see *Documentation of Impact Estimates for Fuel Gas Combustion Device and Flare Regulatory Options for Amendments to the Petroleum Refinery NSPS,* in Docket ID No. EPA–HQ–OAR–2007–0011.

We estimate that the final requirements for flares will reduce emissions of SO_2 by 3,200 tons/yr, NO_X by 1,100 tons/yr and VOC by 3,400 tons/yr from the baseline. The estimated annual cost, including annualized capital costs, is a cost savings of about $79 million (2006 dollars) due to the replacement of some natural gas purchases with recovered flare gas and the retention of intermediate and product streams due to a reduction in the number of malfunctions associated with refinery process units and ancillary equipment connected to the flare. Note that not all refiners will realize a cost savings since we only estimate that refineries with high flare flows will install vapor recovery systems. Although the rule does not specifically require installation of flare gas recovery systems, we project that owners and operators of flares receiving high waste gas flows will conclude, upon installation of monitors, implementation of their flare management plans, and implementation of root causes analyses, that installing flare gas recovery would result in fuel savings by using the recovered flare gas where purchased natural gas is now being used to fire equipment such as boilers and process heaters. The flare management plan requires refiners to conduct a thorough review of the flare system so that flare gas recovery systems are installed and used where these systems are warranted. As part of the development of the flare management plan, refinery owners and operators must provide rationale and supporting evidence regarding the flare waste gas reduction options considered, the quantity of flare gas that would be recovered or prevented by the option, the BTU content of the flare gas and the ability or inability of the reduction option to offset natural gas purchases. In addition, consistent with Executive Order 13563 (Improving Regulation and Regulatory Review, issued on January 18, 2011), for facilities implementing flare gas recovery, we are finalizing provisions that would allow the owner or operator to reduce monitoring costs and the number of root cause analyses, corrective actions, and corresponding recordkeeping and reporting they would need to perform. We estimate that the final requirements for flares will reduce emissions of SO_2 by 3,200 tons/yr, NO_X by 1,100 tons/yr and VOC by 3,400 tons/yr from the baseline. The overall cost effectiveness is a cost savings of about $10,000 per ton of combined pollutants removed. The estimated nationwide 5-year emissions reductions and cost impacts for the final standards are summarized in Table 5 of this preamble.

TABLE 5—NATIONAL EMISSION REDUCTIONS AND COST IMPACTS FOR PETROLEUM REFINERY FLARES SUBJECT TO AMENDED STANDARDS UNDER 40 CFR PART 60, SUBPART JA

[Fifth year after the effective date of these final rule amendments] [a]

Subpart Ja requirements	Total capital cost ($1,000)	Total annual cost without credit ($1,000/yr)	Natural gas offset/product recovery credit ($1,000)	Total annual cost ($1,000/yr)	Annual emission reductions (tons SO_2/yr)	Annual emission reductions (tons NO_X/yr)	Annual emission reductions (tons VOC/yr)	Cost effectiveness ($/ton emissions reduced)
Estimates from June 2008 Final Rule	40,000	.....	.....	(7,000)	80	6	200	(23,000)
Revised Estimates for Amendments	460,000	100,000	(180,000)	(79,000)	3,200	1,100	3,400	(10,000)

[a] All costs in this table are relative to the baseline used for the 2008 final rule.

We also estimate that the final requirements for flares will result in emissions reduction co-benefits of CO_2 equivalents by 1,900,000 metric tonnes per year, predominantly as a result of our estimate of the largest flares employing flare gas recovery and to a lesser extent, as a result of the root cause analyses applicable to all flares.

The cost, environmental and economic impacts for the final amendments to 40 CFR part 60, subpart Ja for process heaters are not expected to be different than those reported for the final June 2008 standards. We expect owners and operators to install the same technology to meet these final amendments that we anticipated they would install to meet the June 2008 final subpart Ja requirements (*i.e.,* ultra-low NO_X burners). We did revise our emission estimates based on the type of process heater, creating separate impacts for forced draft process heaters and natural draft process heaters. Dividing process heaters into separate subcategories, based on the draft type, required us to develop new distributions of baseline emissions for each type of process heater. The baseline emission estimates for natural draft process heaters are slightly lower than those developed for the existing subpart Ja requirements (per affected process heater), but the average emission reduction achieved by ultra-low NO_X burners was adjusted to 80 percent (rather than 75 percent used for generic process heaters). For forced draft process heaters, the baseline (*i.e.,* uncontrolled) emissions rate for forced draft process heaters was revised slightly upward, based on the available emissions data. Due to these differences, the mix of controls needed to meet a 40 ppmv emissions limit was no longer cost effective for forced draft process heaters, but the emission reductions associated with process heaters complying with the 60 ppmv standard were higher than those previously estimated for generic process heaters. Thus, the creation of new subcategories of process heaters with different emissions limits for each subcategory did not impact the control or compliance methods used by the facilities (*i.e.,* BSER in all cases was based on the performance of advanced combustion monitoring controls in conjunction with ultra-low NO_X burners) and did not change the estimated compliance costs. As we do not have adequate data regarding the prevalence of natural draft process heaters versus forced draft process heaters that will become subject to the rule, we used the emission reductions estimated for the two different types of process heaters as a means to bound the range of anticipated NO_X emission reductions to be from 7,100 to 8,600 tons/yr in the fifth year after the effective date of this final rule (see *Revised NO_X Impact Estimates for Process Heaters,* in Docket ID No. EPA–HQ–OAR–2007–0011). We estimated the emission reductions to be 7,500 tons/yr for the June 2008 final standards, which falls well within the anticipated range of emissions reductions for the standards we are finalizing here. Given the uncertainty in the emissions estimates, as well as the uncertainty in the relative number of natural draft process heaters versus forced draft process heaters, we concluded that the impacts previously developed for subpart Ja accurately represent the impacts for process heaters in these final amendments.

We note that, in the preamble to the June 2008 final standards, we estimated costs and emissions reductions for 30 fuel gas combustion devices, but we subsequently determined that those estimates did not fully account for the number of affected flares (which, at the time, were considered a subset of fuel gas combustion devices). Therefore, in the preamble to the December 2008 proposed amendments, we presented revised emission reduction and cost estimates for affected fuel gas combustion devices. As previously explained, we are not finalizing the long-term 60 ppmv H_2S fuel gas concentration limit for flares, as proposed, and we revised our cost estimates accordingly. Because these final amendments consider flares to be a separate affected source, the emission reductions and costs for fuel gas combustion devices are not affected by these final amendments and are not included in this preamble. Rather, the final emission reduction and cost estimates for fuel gas combustion devices are very close to the impacts presented in the June 2008 final rule; the details of the analysis and the final impacts are presented in *Documentation of Impact Estimates for Fuel Gas Combustion Device and Flare Regulatory Options for Amendments to the Petroleum Refinery NSPS,* in Docket ID No. EPA–HQ–OAR–2007–0011.

The final amendments to 40 CFR part 60, subpart J are technical corrections or clarifications to the existing rule and should have no negative emissions impacts.

B. What are the economic impacts?

The total annualized compliance costs are estimated to save about $79 million (2006 dollars) in the fifth year after the effective date of these final amendments. Note that not all refiners will realize a cost savings as only flare systems with high waste gas flows (about 10 percent of all flares) are expected to install vapor recovery systems. Alternatively, if no refineries install flare gas recovery systems, total annualized compliance costs are estimated to be $10.7 million (2006 dollars) in the fifth year after proposal. Regardless of whether any refineries install flare gas recovery systems, we do not anticipate any adverse economic impacts associated with this regulatory action, as no increase in refined petroleum product prices or decrease in refined petroleum product output is expected.

For more information, please refer to the Regulatory Impact Analysis (RIA) that is in the docket for this final rule.

C. What are the benefits?

Emission controls installed to meet the requirements of this rule will generate benefits by reducing emissions of criteria pollutants and their precursors, including SO_2, NO_X and VOC as well as CO_2. SO_2, NO_X and VOC are precursors to $PM_{2.5}$ (particles smaller than 2.5 microns), and NO_X and VOC are precursors to ozone. For this rule, we were only able to quantify the health benefits associated with reduced exposure to $PM_{2.5}$ from emission reductions of SO_2 and NO_X and the climate benefits associated with CO_2 emission reductions. We estimate the monetized benefits of this final regulatory action to be $270 million to $580 million (2006 dollars, 3-percent discount rate) in the fifth year (2017). The benefits at a 7-percent discount rate for health benefits and 3-percent discount rate for climate benefits are $240 million to $530 million (2006 dollars). For small flares only, we estimate the monetized benefits are $170 million to $410 million (3-percent discount rate) and $150 million to $370 million (7-percent discount rate for health benefits and 3-percent discount rate for climate benefits). For large flares only, we estimate the monetized benefits are $93 million to $160 million (3-percent discount rate) and $88 million to $150 million (7-percent discount rate for health benefits and 3-percent discount rate for climate benefits). Using alternate relationships between $PM_{2.5}$ and premature mortality supplied by experts, higher and lower benefits estimates are plausible, but most of the expert-based estimates fall between these two estimates.[12] A summary of the monetized benefits estimates by pollutant for all flares at discount rates of 3 percent and 7 percent is in Table 6 of this preamble. Several benefits categories, including direct exposure to SO_2 and NO_X benefits, ozone benefits, ecosystem benefits and visibility benefits are not included in these monetized benefits. All estimates are in 2006 dollars for the year 2017.

TABLE 6—SUMMARY OF THE MONETIZED $PM_{2.5}$ AND CO_2 BENEFITS FOR AMENDED PETROLEUM REFINERIES STANDARDS

[Millions of 2006 dollars][a]

Pollutant	Emission reductions (tons per year)	Total monetized benefits (3-percent discount)	Total monetized benefits (7-percent discount)
With Flare Gas Recovery			
$PM_{2.5}$ Benefits[b]:			
SO_2	3,200	$210 to $510	$190 to $460.
NO_X	1,100	$7.1 to $18	$6.4 to $16.
PM Total		$220 to $530	$190 to $480.
CO_2 Benefits[c]	1,900,000[d]	$46	$46.
Total Monetized Benefits:		$260 to $580	$240 to $520.
Without Flare Gas Recovery			
$PM_{2.5}$ Benefits[b]:			
SO_2	2,900	$190 to $450	$170 to $410.
NO_X	56	$0.36 to $0.87	$0.32 to $0.78.
PM Total		$190 to $460	$170 to $410.
CO_2 Benefits[c]	110,000[d]	$2.6	$2.6.
Total Monetized Benefits		$190 to $460	$170 to $410.

[a] All estimates are for the analysis year (2017) and are rounded to two significant figures so numbers may not sum across rows. The total monetized benefits reflect the human health benefits associated with reducing exposure to $PM_{2.5}$ through reductions of $PM_{2.5}$ precursors, such as NO_X and SO_2, as well as CO_2. It is important to note that the monetized benefits do not include reduced health effects from direct exposure to SO_2 and NO_X, ozone exposure, ecosystem effects or visibility impairment.

[b] PM benefits are shown as a range from Pope, *et al.* (2002) to Laden, *et al.* (2006). These models assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because the scientific evidence is not yet sufficient to allow differentiation of effects estimates by particle type.

[c] The CO_2 emission reductions (shown in metric tonnes) have been reduced to reflect the anticipated emission increases associated with the energy disbenefits. CO_2-related benefits were calculated using the social cost of carbon (SCC), which is discussed further in the RIA. The net present value of reduced CO_2 emissions is calculated differently than other benefits. This table shows monetized climate benefits using the global average SCC estimate at a 3-percent discount rate because the interagency workgroup deemed the SCC at a 3-percent discount rate to be the central value. In the RIA, we also provide the monetized CO_2 benefits using discount rates of 5 percent (average), 2.5 percent (average) and 3 percent (95th percentile).

[d] Metric tonnes

These benefits estimates represent the total monetized human health benefits for populations exposed to less $PM_{2.5}$ in 2017 from controls installed to reduce air pollutants in order to meet this rule. To estimate human health benefits of this rule, the EPA used benefit-per-ton factors to quantify the changes in $PM_{2.5}$-related health impacts and monetized benefits based on changes in SO_2 and NO_X emissions. These benefit-per-ton factors were derived using the general approach and methodology laid out in Fann, Fulcher, and Hubbell (2009).[13] This approach uses a model to convert emissions of $PM_{2.5}$ precursors into changes in ambient $PM_{2.5}$ levels and another model to estimate the changes in human health associated with that change in air quality, which are then divided by the emission reductions to

[12] Roman, *et al.*, 2008. *Expert Judgment Assessment of the Mortality Impact of Changes in Ambient Fine Particulate Matter in the U.S.*, Environ. Sci. Technol., 42, 7, 2268—2274.

[13] Fann, N., C.M. Fulcher, B.J. Hubbell. 2009. *The Influence of Location, Source, and Emission Type in Estimates of the Human Health Benefits of Reducing a Ton of Air Pollution.* Air Qual Atmos Health (2009) 2:169–176.

create the benefit-per-ton estimates. However, for this rule, we use air quality modeling data specific to the petroleum refineries sector.[14] The primary difference between the estimates used in this analysis and the estimates reported in Fann, Fulcher, and Hubbell (2009) is the air quality modeling data utilized. While the air quality data used in Fann, Fulcher, and Hubbell (2009) reflects broad pollutant/source category combinations, such as all non-electric generating unit stationary point sources, the air quality modeling data used in this analysis is sector-specific. In addition, the updated air quality modeling data reflects more recent emissions data (2005 rather than 2001) and has a higher spatial resolution (12 kilometers (km) rather than 36 km grid cells). As a result, the benefit-per-ton estimates presented herein better reflect the geographic areas and populations likely to be affected by this sector. The benefits methodology, such as health endpoints assessed, risk estimates applied and valuation techniques applied did not change. However, these updated estimates still have similar limitations as all national-average benefit-per-ton estimates in that they reflect the geographic distribution of the modeled emissions, which may not exactly match the emission reductions in this rulemaking, and they may not reflect local variability in population density, meteorology, exposure, baseline health incidence rates or other local factors for any specific location.

We apply these national benefit-per-ton estimates calculated for this sector separately for SO_2 and NO_X and multiply them by the corresponding emission reductions. The sector-specific modeling does not provide estimates of the $PM_{2.5}$-related benefits associated with reducing VOC emissions, but these unquantified benefits are generally small compared to other $PM_{2.5}$ precursors. More information regarding the derivation of the benefit-per-ton estimates for the petroleum refining sector is available in the technical support document, which is available in the docket.

These models assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because the scientific evidence is not yet sufficient to allow differentiation of effects estimates by particle type. The main $PM_{2.5}$ precursors affected by this rule are SO_2 and NO_X. Even though we assume that all fine particles have equivalent health effects, the benefit-per-ton estimates vary between precursors depending on the location and magnitude of their impact on $PM_{2.5}$ levels, which drive population exposure. For example, SO_2 has a lower benefit-per-ton estimate than direct $PM_{2.5}$ because it does not form as much $PM_{2.5}$, thus, the exposure would be lower, and the monetized health benefits would be lower.

It is important to note that the magnitude of the $PM_{2.5}$ benefits is largely driven by the concentration response function for premature mortality. Experts have advised the EPA to consider a variety of assumptions, including estimates based both on empirical (epidemiological) studies and judgments elicited from scientific experts, to characterize the uncertainty in the relationship between $PM_{2.5}$ concentrations and premature mortality. We cite two key empirical studies, one based on the American Cancer Society cohort study [15] and the extended Six Cities cohort study.[16] In the RIA for this final rule, which is available in the docket, we also include benefits estimates derived from the expert judgments and other assumptions.

The EPA strives to use the best available science to support our benefits analyses. We recognize that interpretation of the science regarding air pollution and health is dynamic and evolving. After reviewing the scientific literature, we have determined that the no-threshold model is the most appropriate model for assessing the mortality benefits associated with reducing $PM_{2.5}$ exposure. Consistent with this finding, we have conformed the previous threshold sensitivity analysis to the current state of the PM science by incorporating a new "Lowest Measured Level" (LML) assessment in the RIA accompanying this rule. While an LML assessment provides some insight into the level of uncertainty in the estimated PM mortality benefits, the EPA does not view the LML as a threshold and continues to quantify PM-related mortality impacts using a full range of modeled air quality concentrations.

Most of the estimated PM-related benefits in this rule would accrue to populations exposed to higher levels of $PM_{2.5}$. For this analysis, policy-specific air quality data is not available due to time or resource limitations, thus, we are unable to estimate the percentage of premature mortality associated with this specific rule's emission reductions at each $PM_{2.5}$ level. As a surrogate measure of mortality impacts, we provide the percentage of the population exposed at each $PM_{2.5}$ level using the source apportionment modeling used to calculate the benefit-per-ton estimates for this sector. Using the Pope, *et al.* (2002) study, 77 percent of the population is exposed to annual mean $PM_{2.5}$ levels at or above the LML of 7.5 micrograms per cubic meter ($\mu g/m^3$). Using the Laden, *et al.* (2006) study, 25 percent of the population is exposed above the LML of 10 $\mu g/m^3$. It is important to emphasize that we have high confidence in $PM_{2.5}$-related effects down to the lowest LML of the major cohort studies. This fact is important, because, as we model avoided premature deaths among populations exposed to levels of $PM_{2.5}$, we have lower confidence in levels below the LML for each study.

Every benefit analysis examining the potential effects of a change in environmental protection requirements is limited, to some extent, by data gaps, model capabilities (such as geographic coverage) and uncertainties in the underlying scientific and economic studies used to configure the benefit and cost models. Despite these uncertainties, we believe the benefit analysis for this rule provides a reasonable indication of the expected health benefits of the rulemaking under a set of reasonable assumptions. This analysis does not include the type of detailed uncertainty assessment found in the 2006 $PM_{2.5}$ NAAQS RIA because we lack the necessary air quality input and monitoring data to run the benefits model. In addition, we have not conducted air quality modeling for this rule, and using a benefit-per-ton approach adds another important source of uncertainty to the benefits estimates. The 2006 $PM_{2.5}$ NAAQS benefits analysis [17] provides an indication of the sensitivity of our results to various assumptions.

This rule is expected to reduce CO_2 emissions from the electricity sector. The EPA has assigned a dollar value to reductions in CO_2 emissions using recent estimates of the "social cost of carbon" (SCC). The SCC is an estimate

[14] U.S. Environmental Protection Agency. 2011. *Technical Support Document: Estimating the Benefit per Ton of Reducing $PM_{2.5}$ Precursors from the Petroleum Refineries Sector.* EPA, Research Triangle Park, NC.

[15] Pope, *et al.*, 2002. *Lung Cancer, Cardiopulmonary Mortality, and Long-term Exposure to Fine Particulate Air Pollution.* Journal of the American Medical Association 287:1132–1141.

[16] Laden, *et al.*, 2006. *Reduction in Fine Particulate Air Pollution and Mortality.* American Journal of Respiratory and Critical Care Medicine 173: 667–672.

[17] U.S. Environmental Protection Agency, 2006. *Final Regulatory Impact Analysis: $PM_{2.5}$ NAAQS.* Prepared by Office of Air and Radiation. October. Available on the Internet at *http://www.epa.gov/ttn/ecas/ria.html.*

of the monetized damages associated with an incremental increase in carbon emissions in a given year or the per metric ton benefit estimate relating to decreases in CO_2 emissions. It is intended to include (but is not limited to) changes in net agricultural productivity, human health, property damage from increased flood risk, and the value of ecosystem services due to climate change.

The SCC estimates used in this analysis were developed through an interagency process that included the EPA and other executive branch entities, and that concluded in February 2010. We first used these SCC estimates in the benefits analysis for the final joint EPA/DOT Rulemaking to establish Light-Duty Vehicle Greenhouse Gas Emission Standards and Corporate Average Fuel Economy Standards; see the rule's preamble for discussion about application of the SCC (75 FR 25324; May 7, 2010). The SCC Technical Support Document (SCC TSD) provides a complete discussion of the methods used to develop these SCC estimates.[18]

The interagency group selected four SCC values for use in regulatory analyses, which we have applied in this analysis: $5.9, $24.3, $39, and $74.4 per metric ton of CO_2 emissions in 2016, in 2007 dollars. The first three values are based on the average SCC from three integrated assessment models, at discount rates of 5, 3 and 2.5 percent, respectively. Social cost of carbon values at several discount rates are included because the literature shows that the SCC is quite sensitive to assumptions about the discount rate, and because no consensus exists on the appropriate rate to use in an intergenerational context. The fourth value is the 95th percentile of the SCC from all three values at a 3-percent discount rate. It is included to represent higher-than-expected impacts from temperature change further out in the extremes of the SCC distribution. Low probability, high impact events are incorporated into all of the SCC values through explicit consideration of their effects in two of the three values as well as the use of a probability density function for equilibrium climate sensitivity. Treating climate sensitivity probabilistically results in more high temperature outcomes, which in turn leads to higher projections of damages.

Applying the global SCC estimates using a 3-percent discount rate, we estimate the value of the climate related benefits of this rule in 2017 is $49 million (2006$), as shown in Table 6. See the RIA for more detail on the methodology used to calculate these benefits and additional estimates of climate benefits using different discount rates and the 95th percentile of the 3-percent discount rate SCC. Important limitations and uncertainties of the SCC approach are also described in the RIA.

It should be noted that the monetized benefits estimates provided above do not include benefits from several important benefit categories, including direct exposure to SO_2 and NO_X, ozone exposure, ecosystem effects and visibility impairment. Although we do not have sufficient information or modeling available to provide monetized estimates for this rulemaking, we include a qualitative assessment of these unquantified benefits in the RIA for this final rule.

Although this final rule provides refiners with some additional compliance options and removes some requirements, such as the long-term H_2S limit for flares, these are non-monetized benefits of the rule.

For more information on the benefits analysis, please refer to the RIA for this rulemaking, which is available in the docket.

VI. Statutory and Executive Order Reviews

A. Executive Order 12866: Regulatory Planning and Review and Executive Order 13563: Improving Regulation and Regulatory Review

Under section 3(f)(1) of Executive Order 12866 (58 FR 51735, October 4, 1993), this action is an "economically significant regulatory action" because it is likely to have an annual effect on the economy of $100 million or more. Accordingly, the EPA submitted this action to the Office of Management and Budget (OMB) for review under Executive Order 12866 and Executive Order 13563 (76 FR 3821, January 21, 2011), and any changes made in response to OMB recommendations have been documented in the docket for this action. In addition, the EPA prepared a RIA of the potential costs and benefits associated with this action.

A summary of the monetized benefits, compliance costs and net benefits for the final rule at discount rates of 3 percent and 7 percent is in Table 7 of this preamble.

TABLE 7—SUMMARY OF THE MONETIZED BENEFITS, COMPLIANCE COSTS AND NET BENEFITS FOR THE FINAL PETROLEUM REFINERIES NSPS IN 2017

[Millions of 2006 dollars][a]

	3-Percent discount rate	7-Percent discount rate
Total Monetized Benefits[b]	$270 to $580	$240 to $530.
Total Compliance Costs[c]	−$79	−$79.
Net Benefits	$340 to $660	$320 to $610.
Non-Monetized Benefits	Health effects from direct exposure to SO_2 and NO_2.	
	Health effects from $PM_{2.5}$ exposure from VOC	
	Ecosystem effects.	
	Visibility impairment.	

[a] All estimates are for the implementation year (2017) and are rounded to two significant figures.

[18] Docket ID EPA–HQ–OAR–2009–0472–114577, *Technical Support Document: Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866, Interagency Working Group on Social Cost of Carbon*, with participation by Council of Economic Advisers, Council on Environmental Quality, Department of Agriculture, Department of Commerce, Department of Energy, Department of Transportation, Environmental Protection Agency, National Economic Council, Office of Energy and Climate Change, Office of Management and Budget, Office of Science and Technology Policy, and Department of Treasury (February 2010). Also available at *http://epa.gov/otaq/climate/regulations.htm*.

[b] The total monetized benefits reflect the human health benefits associated with reducing exposure to $PM_{2.5}$ through reductions of $PM_{2.5}$ precursors such as NO_X and SO_2, as well as CO_2 benefits. It is important to note that the monetized benefits do not include the reduced health effects from direct exposure to SO_2 and NO_X, ozone exposure, ecosystem effects or visibility impairment. Human health benefits are shown as a range from Pope, *et al.* (2002) to Laden, *et al.* (2006). These models assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because the scientific evidence is not yet sufficient to allow differentiation of effects estimates by particle type. The net present value of reduced CO_2 emissions is calculated differently than other benefits. This table includes monetized climate benefits using the global average social cost of carbon (SCC) estimated at a 3-percent discount rate because the interagency work group deemed the SCC estimate at a 3-percent discount rate to be the central value.

[c] The engineering compliance costs are annualized using a 7-percent discount rate.

To support the determination of BSER for the June 24, 2008, final rule, we considered a number of regulatory options and their costs and benefits. Those results are presented in the RIA for the June 24, 2008, final rulemaking, which is available in the docket. These final rule amendments are in response to comments received on the December 22, 2008, proposed rule amendments. Costs and benefits associated with the amendments in this final rule differ from the June 24, 2008, final rule and the December 22, 2008, proposed rule amendments primarily as a result of correcting the number of flares projected to have to comply with this rule (*i.e.,* 400 affected flares in this rule compared to 40 estimated in the June 24, 2008, final rule and 150 in the December 22, 2008, proposed amendments). In addition, the amendments in this final rule to address comments received for the other fuel gas combustion devices do not affect the projected costs and benefits from the December 22, 2008, proposal, which also did not change from the June 24, 2008, final rule. Therefore, for purposes of developing these final rule amendments, we did not re-evaluate the suite of regulatory options for flares and other fuel gas combustion devices considered to support the June 24, 2008, final rule. However, even with the flare count adjustment, this final rule is consistent with Executive Order 13563 (Improving Regulation and Regulatory Review) because the monetized benefits of this final rule exceed the costs. In addition, for facilities implementing flare gas recovery, we are reducing regulatory burden by finalizing provisions that would allow the owner or operator to reduce monitoring costs and the number of root cause analyses, corrective actions and corresponding recordkeeping and reporting they would need to perform.

For more information on the cost-benefits analysis, please refer to the RIA for this rulemaking, which is available in the docket.

B. Paperwork Reduction Act

The final amendments to the Standards of Performance for Petroleum Refineries (40 CFR part 60, subpart J) do not impose any new information collection burden. The final amendments are clarifications and technical corrections that do not affect the estimated burden of the existing rule. Therefore, we have not revised the ICR for the existing rule. However, OMB has previously approved the information collection requirements contained in the existing rule (40 CFR part 60, subpart J) under the provisions of the Paperwork Reduction Act, 44 U.S.C. 3501, *et seq.,* and has assigned OMB control number 2060–0022. The OMB control numbers for the EPA's regulations are listed in 40 CFR part 9.

The OMB has approved the information collection requirements in the amendments to the Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007 (40 CFR part 60, subpart Ja) under the provisions of the Paperwork Reduction Act, 44 U.S.C. 3501, *et seq.,* and has assigned OMB control number 2060–0602.

The information requirements in these final amendments add new compliance options, provide more time to comply with the requirements for flares, clarify the flare management plan requirements and clarify the flare modification provision. Overall, these changes are expected to reduce the costs associated with testing, monitoring, recording and reporting, so they will not result in any increase in burden for the affected facilities for which the EPA previously estimated the burden. However, the EPA has revised the number of flares expected to become subject to the rule over the first 3 years of the ICR. Therefore, the annual burden was estimated for the additional affected facilities. The total burden for 40 CFR part 60, subpart Ja can be estimated by summing the previously approved annual burden for OMB control number 2060–0602 (5,340 labor-hours per year at a cost of $481,249 per year, annualized capital costs of $2,052,000 per year, and operation and maintenance costs of $1,117,440 per year) and the annual burden for this ICR, as described below.

The annual burden for this information collection averaged over the first 3 years of this ICR is estimated to total 54,572 labor-hours per year at a cost of $4,918,110 per year. The annualized capital costs are estimated at $11,266,000 per year and operation and maintenance costs are estimated at $8,750,000 per year. We note that the capital costs, as well as the operation and maintenance costs, are for the continuous monitors; these costs are also included in the cost impacts presented in section V.A of this preamble. Therefore, the burden costs associated with the continuous monitors presented in the ICR are not additional costs incurred by affected sources subject to final 40 CFR part 60, subpart Ja. Burden is defined at 5 CFR 1320.3(b).

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for the EPA's regulations are listed in 40 CFR part 9. The EPA is amending the table in 40 CFR part 9 of currently approved ICR control numbers for various regulations to list regulatory citations for the information requirements contained in this final rule. This amendment updates the table to list the information collection requirements being promulgated here as amendments to the NSPS for petroleum refineries.

The EPA will continue to present OMB control numbers in a consolidated table format to be codified in 40 CFR part 9 of the agency's regulations and in each CFR volume containing the EPA regulations. The table lists the section numbers with reporting and recordkeeping requirements and the current OMB control numbers. This listing of the OMB control numbers and their subsequent codification in the CFR satisfy the requirements of the Paperwork Reduction Act (44 U.S.C. 3501, *et seq.*) and OMB's implementing regulations at 5 CFR part 1320.

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 organizations and small governmental jurisdictions.

For purposes of assessing the impact of this final 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.

While we estimated the natural gas recovery offsets or credit at a national level and believe that larger firms are more likely to offset natural gas purchases, the revenues from natural gas recovery offsets might mask disproportionate impacts on small refiners. To better identify disproportionate impacts, we examined the potential impacts on refiners based on a scenario where no firms adopt flare gas recovery systems and comply with the NSPS through flare monitoring and flare management and root cause analysis actions. The incremental compliance costs imposed on small refineries are not estimated to create significant impacts on a cost-to-sales ratio basis at the firm level. Therefore, no adverse economic impacts are expected for any small or large entity.

After considering the economic impacts of these final amendments on small entities, I certify that this action will not have a significant economic impact on a substantial number of small entities. The small entities directly regulated by these final amendments are small petroleum refineries. We have determined that 31 small refiners, or 55 percent of total refiners, will experience an impact of between less than 0.01 percent up to 0.63 percent of revenues.

D. Unfunded Mandates Reform Act

This rule 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 the private sector in any one year. The costs of the final amendments would not increase costs associated with the final rule. Thus, this rule is not subject to the requirements of sections 202 or 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 final amendments contain no requirements that apply to such governments and impose no obligations upon them.

E. Executive Order 13132: Federalism

This action 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. This action does 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 action.

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 final amendments impose no requirements on tribal governments. Thus, Executive Order 13175 does not apply to this action.

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

The 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 action 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 final 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 of 1995 (NTTAA), Public Law 104–113, 12(d) (15 U.S.C. 272 note) directs the 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 the EPA to provide Congress, through OMB, explanations when the agency decides not to use available and applicable VCS.

This rulemaking involves technical standards. The EPA has decided 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 D3588–98 (Reapproved 2003), *Standard Practice for Calculating Heat Value, Compressibility Factor, and Relative Density of Gaseous Fuels;* 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 (Reapproved 2010), *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 has decided to use the following VCS as acceptable alternatives to EPA 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–2004, *Measurement of Fluid Flow in Pipes Using Orifice, Nozzle, and Venturi;* ANSI/ASME MFC–4M–1986 (Reaffirmed 2008), *Measurement of Gas Flow by Turbine Meters;* ASME MFC–6M–1998 (Reaffirmed 2005), *Measurement of Fluid Flow in Pipes Using Vortex Flowmeters;* ASME/ANSI MFC–7M–1987 (Reaffirmed 2006), *Measurement of Gas Flow by Means of Critical Flow Venturi Nozzles;* ASME MFC–11M–2006, *Measurement of Fluid Flow by Means of Coriolis Mass Flowmeters;* ASME MFC–14M–2003, *Measurement of Fluid Flow Using Small Bore Precision Orifice Meters;* and ASME MFC–18M–2001, *Measurement of Fluid Flow Using Variable Area Meters.*

The EPA has also decided to use the following VCS as acceptable alternatives to EPA Methods 2, 2A, 2B, 2C or 2D for conducting relative accuracy evaluations of fuel oil flow monitors: ANSI/ASME MFC–5M–1985 (Reaffirmed 2006), *Measurement of Liquid Flow in Closed Conduits Using Transit-Time Ultrasonic Flowmeters;* ASME/ANSI MFC–9M–1988 (Reaffirmed 2006), *Measurement of Liquid Flow in Closed Conduits by Weighing Method;* ASME MFC–16–2007, *Measurement of Liquid Flow in Closed Conduits with Electromagnetic Flowmeters;* ASME MFC–22–2007, *Measurement of Liquid by Turbine Flowmeters;* and ISO 8316: *Measurement of Liquid Flow in Closed Conduits—Method by Collection of the Liquid in a Volumetric Tank (1987–10–01)—First Edition.*

The EPA has decided 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 H_2S: ANSI/ASME PTC 19.10–1981, *Flue and Exhaust Gas Analyses.* The EPA has decided 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.*

The EPA has decided to use the following VCS as acceptable alternatives to EPA Method 18 for relative accuracy evaluations of gas composition analyzers for gas-fired process heaters: ASTM D1945–03 (Reapproved 2010), *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 UOP539–97, *Refinery Gas Analysis by Gas Chromatography;* and ASTM D6420–99 (Reapproved 2004), *Standard Test Method for Determination of Gaseous Organic Compounds by Direct Interface Gas Chromatography-Mass Spectrometry.* However, ASTM D6420–99 is a suitable alternative to EPA 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 40 CFR 60.17).

The EPA has also decided to use American Gas Association *Report No. 3: Orifice Metering for Natural Gas and Other Related Hydrocarbon Fluids, Part 1: General Equations and Uncertainty Guidelines* (1990), American Gas Association *Report No. 3: Orifice Metering for Natural Gas and Other Related Hydrocarbon Fluids, Part 2: Specification and Installation Requirements* (2000), American Gas Association *Report No. 11: Measurement of Natural Gas by Coriolis Meter* (2003), American Gas Association *Transmission Measurement Committee Report No. 7, Measurement of Natural Gas by Turbine Meters* (Revised February 2006) and API's *Manual of Petroleum Measurement Standards, Chapter 22—Testing Protocol, Section 2—Differential Pressure Flow Measurement Devices,* First Edition, August 2005, for conducting relative accuracy evaluations of fuel gas flow monitors; Gas Processors Association (GPA) Standard 2261–00, *Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography* (2000), for relative accuracy evaluations of gas composition analyzers for gas-fired process heaters; and GPA 2172–09, *Calculation of Gross Heating Value, Relative Density, Compressibility and Theoretical Hydrocarbon Liquid Content for Natural Gas Mixtures for Custody Transfer,* for determining the higher heating value of fuel fed to process heaters. These methods are also incorporated by reference (see 40 CFR 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 be 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.

Under 40 CFR 60.13(i) of the NSPS General Provisions, a source may apply to the 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.

The EPA has determined that this final 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 final amendments are either clarifications or compliance alternatives which will neither increase or decrease environmental protection.

K. Congressional Review Act

The Congressional Review Act, 5 U.S.C. 801, *et seq.,* as added by the Small Business Regulatory Enforcement Fairness Act of 1996, generally provides that before a rule may take effect the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of Congress and to the Comptroller General of the United States. The EPA will submit a report containing these final rules and other required information to the United States Senate, the United States House of Representatives and the Comptroller General of the United States prior to publication of the final rules in the **Federal Register**. A major rule cannot take effect until 60 days after it is published in the **Federal Register**. This action is a ''major rule'' as defined by 5 U.S.C. 804(2). This final rule will be effective on November 13, 2012.

List of Subjects

40 CFR Part 9

Environmental protection, Reporting and recordkeeping requirements.

40 CFR Part 60

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

Dated: June 1, 2012.

Lisa P. Jackson,

Administrator.

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

PART 9—[AMENDED]

■ 1. The authority citation for part 9 continues to read as follows:

Authority: 7 U.S.C. 135, *et seq.*, 136–136y; 15 U.S.C. 2001, 2003, 2005, 2006, 2601–2671; 21 U.S.C. 331j, 346a, 348; 31 U.S.C. 9701; 33 U.S.C. 1251, *et seq.*, 1311, 1313d, 1314, 1318, 1321, 1326, 1330, 1342, 1344, 1345(d) and (e), 1361; E.O. 11735, 38 FR 21243, 3 CFR, 1971–1975 Comp. p. 973; 42 U.S.C. 241, 242b, 243, 246, 300f, 300g, 300g–1, 300g–2, 300g–3, 300g–4, 300g–5, 300g–6, 300j–1, 300j–2, 300j–3, 300j–4, 300j–9, 1857, *et seq.*, 6901–6992k, 7401–7671q, 7542, 9601–9657, 11023, 11048.

■ 2. The table in Section 9.1 is amended by adding an entry in numerical order for 60.103a–60.108a under the heading ''Standards of Performance for New Stationary Sources'' to read as follows:

§ 9.1 OMB Approvals under the Paperwork Reduction Act.

* * * * *

40 CFR citation	OMB control No.
* * * * *	
Standards of Performance for New Stationary Sources [1]	
* * * * *	
60.103a–60.108a	2060–0602
* * * * *	

[1] The ICRs referenced in this section of the table encompass the applicable general provisions contained in 40 CFR part 60, subpart A, which are not independent information collection requirements.

* * * * *

PART 60—[AMENDED]

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

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

Subpart A—[AMENDED]

■ 4. Section 60.17 is amended by:
■ a. Revising paragraphs (a)(84), (a)(95), (a)(96), (a)(97), and (a)(98);
■ b. Adding paragraphs (a)(100) through (a)(108);
■ c. Adding paragraph (c)(2);
■ d. Revising paragraph (h)(4) and adding paragraphs (h)(5) through (h)(15);
■ e. Adding paragraphs (m)(2) and (m)(3); and
■ f. Adding paragraphs (p) and (q) to read as follows:

§ 60.17 Incorporations by reference.

* * * * *

(a) * * *

(84) ASTM D6420–99 (Reapproved 2004), Standard Test Method for Determination of Gaseous Organic Compounds by Direct Interface Gas Chromatography-Mass Spectrometry, (Approved October 1, 2004), IBR approved for § 60.107a(d) of subpart Ja and table 2 of subpart JJJJ of this part.

* * * * *

(95) ASTM D3588–98 (Reapproved 2003), Standard Practice for Calculating Heat Value, Compressibility Factor, and Relative Density of Gaseous Fuels, (Approved May 10, 2003), IBR approved for §§ 60.107a(d) and 60.5413(d).

(96) ASTM D4891–89 (Reapproved 2006), Standard Test Method for Heating Value of Gases in Natural Gas Range by Stoichiometric Combustion, (Approved June 1, 2006), IBR approved for §§ 60.107a(d) and 60.5413(d).

(97) ASTM D1945–03 (Reapproved 2010), Standard Method for Analysis of Natural Gas by Gas Chromatography, (Approved January 1, 2010), IBR approved for §§ 60.107a(d) and 60.5413(d).

(98) ASTM D5504–08, Standard Test Method for Determination of Sulfur Compounds in Natural Gas and Gaseous Fuels by Gas Chromatography and Chemiluminescence, (Approved June 15, 2008), IBR approved for §§ 60.107a(e) and 60.5413(d).

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(100) ASTM D4468–85 (Reapproved 2006), Standard Test Method for Total Sulfur in Gaseous Fuels by Hydrogenolysis and Rateometric Colorimetry (Approved June 1, 2006), IBR approved for § 60.107a(e).

(101) ASTM D240–02 (Reapproved 2007), Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter, (Approved May 1, 2007), IBR approved for § 60.107a(d).

(102) ASTM D1826–94 (Reapproved 2003), Standard Test Method for Calorific (Heating) Value of Gases in Natural Gas Range by Continuous Recording Calorimeter, (Approved May 10, 2003), IBR approved for § 60.107a(d).

(103) ASTM D1946–90 (Reapproved 2006), Standard Method for Analysis of Reformed Gas by Gas Chromatography, (Approved June 1, 2006), IBR approved for § 60.107a(d).

(104) ASTM D4809–06, Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter (Precision Method), (Approved December 1, 2006), IBR approved for § 60.107a(d).

(105) ASTM UOP539–97, Refinery Gas Analysis by Gas Chromatography, (Copyright 1997), IBR approved for § 60.107a(d).

(106) ASTM D3699–08, Standard Specification for Kerosine, including Appendix X1, (Approved September 1, 2008), IBR approved for §§ 60.41b of subpart Db and 60.41c of subpart Dc of this part.

(107) ASTM D6751–11b, Standard Specification for Biodiesel Fuel Blend Stock (B100) for Middle Distillate Fuels, including Appendices X1 through X3, (Approved July 15, 2011), IBR approved for §§ 60.41b of subpart Db and 60.41c of subpart Dc of this part.

(108) ASTM D7467–10, Standard Specification for Diesel Fuel Oil, Biodiesel Blend (B6 to B20), including Appendices X1 through X3, (Approved August 1, 2010), IBR approved for §§ 60.41b of subpart Db and 60.41c of subpart Dc of this part.

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(c) * * *

(2) American Petroleum Institute (API) Manual of Petroleum Measurement Standards, Chapter 22-Testing Protocol, Section 2-Differential Pressure Flow Measurement Devices, First Edition, August 2005, IBR approved for § 60.107a(d) of subpart Ja of this part.

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(h) * * *

(4) ANSI/ASME PTC 19.10–1981, Flue and Exhaust Gas Analyses [Part 10, Instruments and Apparatus], (Issued August 31, 1981), IBR approved for § 60.56c(b), § 60.63(f), § 60.106(e), § 60.104a(d), (h), (i), and (j), § 60.105a(d), (f), and (g), § 60.106a(a), § 60.107a(a), (c), and (e), tables 1 and 3 of subpart EEEE, tables 2 and 4 of subpart FFFF, table 2 of subpart JJJJ, §§ 60.4415(a), 60.2145(s), 60.2145(t),

60.2710(s), 60.2710(t), 60.2710(w), 60.2730(q), 60.4900(b), 60.5220(b), tables 1 and 2 to subpart LLLL, tables 2 and 3 to subpart MMMM, §§ 60.5406(c) and 60.5413(b).

(5) ASME MFC–3M–2004, Measurement of Fluid Flow in Pipes Using Orifice, Nozzle, and Venturi, IBR approved for § 60.107a(d) of subpart Ja of this part.

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

(7) ANSI/ASME–MFC–5M–1985 (Reaffirmed 2006), Measurement of Liquid Flow in Closed Conduits Using Transit-Time Ultrasonic Flowmeters, IBR approved for § 60.107a(d) 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) of subpart Ja of this part.

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

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

(11) ASME MFC–11M–2006, Measurement of Fluid Flow by Means of Coriolis Mass Flowmeters, IBR approved for § 60.107a(d) of subpart Ja of this part.

(12) ASME MFC–14M–2003, Measurement of Fluid Flow Using Small Bore Precision Orifice Meters, IBR approved for § 60.107a(d) of subpart Ja of this part.

(13) ASME MFC–16–2007, Measurement of Liquid Flow in Closed Conduits with Electromagnetic Flowmeters, IBR approved for § 60.107a(d) of subpart Ja of this part.

(14) ASME MFC–18M–2001, Measurement of Fluid Flow Using Variable Area Meters, IBR approved for § 60.107a(d) of subpart Ja of this part.

(15) ASME MFC–22–2007, Measurement of Liquid by Turbine Flowmeters, IBR approved for § 60.107a(d) of subpart Ja of this part.

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(m) * * *

(2) Gas Processors Association Standard 2172–09, Calculation of Gross Heating Value, Relative Density, Compressibility and Theoretical Hydrocarbon Liquid Content for Natural Gas Mixtures for Custody Transfer (2009), IBR approved for § 60.107a(d) of subpart Ja of this part.

(3) Gas Processors Association Standard 2261–00, Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography (2000), IBR approved for § 60.107a(d) of subpart Ja of this part.

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(p) 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 Report No. 3: Orifice Metering for Natural Gas and Other Related Hydrocarbon Fluids, Part 1: General Equations and Uncertainty Guidelines (1990), IBR approved for § 60.107a(d) of subpart Ja of this part.

(2) American Gas Association Report No. 3: Orifice Metering for Natural Gas and Other Related Hydrocarbon Fluids, Part 2: Specification and Installation Requirements (2000), IBR approved for § 60.107a(d) of subpart Ja of this part.

(3) American Gas Association Report No. 11: Measurement of Natural Gas by Coriolis Meter (2003), IBR approved for § 60.107a(d) of subpart Ja of this part.

(4) American Gas Association Transmission Measurement Committee Report No. 7: Measurement of Gas by Turbine Meters (Revised February 2006), IBR approved for § 60.107a(d) of subpart Ja of this part.

(q) The following material is available for purchase from the International Standards Organization (ISO), 1, ch. de la Voie-Creuse, Case postale 56, CH–1211 Geneva 20, Switzerland, +41 22 749 01 11, *http://www.iso.org/iso/home.htm.*

(1) ISO 8316: Measurement of Liquid Flow in Closed Conduits—Method by Collection of the Liquid in a Volumetric Tank (1987–10–01)—First Edition, IBR approved for § 60.107a(d) of subpart Ja of this part.

(2) [Reserved]

Subpart J—[AMENDED]

■ 5. Section 60.100 is amended by:
■ a. Revising paragraph (b);
■ b. Redesignating paragraph (e) as (f); and
■ c. Adding a new paragraph (e) to read as follows:

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

* * * * *

(b) Any fluid catalytic cracking unit catalyst regenerator or fuel gas combustion device under paragraph (a) of this section other than a flare which commences construction, reconstruction or modification after June 11, 1973, and on or before May 14, 2007, or any fuel gas combustion device under paragraph (a) of this section that is also a flare which commences construction, reconstruction or modification after June 11, 1973, and on or before June 24, 2008, or any Claus sulfur recovery plant under paragraph (a) of this section which commences construction, reconstruction or modification after October 4, 1976, and on or before May 14, 2007, is subject to the requirements of this subpart except as provided under paragraphs (c) through (e) of this section.

* * * * *

(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.

* * * * *

■ 6. Section 60.101 is amended by revising paragraph (d) to read as follows:

§ 60.101 Definitions.

* * * * *

(d) *Fuel gas* means any gas which is generated at a petroleum refinery and which is combusted. Fuel gas includes natural gas when the natural gas is combined and combusted in any proportion with a gas generated at a refinery. Fuel gas does not include gases generated by catalytic cracking unit catalyst regenerators and fluid coking burners. Fuel gas does not include vapors that are collected and combusted in a thermal oxidizer or flare installed to control emissions from wastewater treatment units or marine tank vessel loading operations.

* * * * *

■ 7. 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]

■ 7. In § 60.100a, lift the stay on paragraph (c) published December 22, 2008 (73 FR 78552).

■ 8. Section 60.100a is amended by:
■ a. Revising paragraph (a);
■ b. Revising paragraph (b);
■ c. Revising paragraph (c) introductory text and paragraph (c)(1); and
■ d. Revising paragraph (d).

The revisions read as follows:

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

(a) The provisions of this subpart apply to the following affected facilities in petroleum refineries: fluid catalytic cracking units (FCCU), fluid coking units (FCU), delayed coking units, fuel gas combustion devices (including process heaters), flares and sulfur recovery plants. The sulfur recovery plant need not be physically located within the boundaries of a petroleum refinery to be an affected facility, provided it processes gases produced within a petroleum refinery.

(b) Except for flares and delayed coking units, the provisions of this subpart apply only to affected facilities under paragraph (a) of this section which commence construction, modification or reconstruction after May 14, 2007. For flares, the provisions of this subpart apply only to flares which commence construction, modification or reconstruction after June 24, 2008. For the purposes of this subpart, a modification to a flare commences when a project that includes any of the activities in paragraphs (c)(1) or (2) of this section is commenced. For delayed coking units, the provisions of this subpart apply to delayed coking units that commence construction, reconstruction or modification on the earliest of the following dates:

(1) May 14, 2007, for such activities that involve a "delayed coking unit" defined as follows: one or more refinery process units in which high molecular weight petroleum derivatives are thermally cracked and petroleum coke is produced in a series of closed, batch system reactors;

(2) December 22, 2008, for such activities that involve a "delayed coking unit" defined as follows: 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;

(3) September 12, 2012, for such activities that involve a "delayed coking unit" as defined in § 60.101a.

(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, including ancillary equipment, or a 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 (vii) 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 or connections made to upgrade or enhance components of a flare gas recovery system (*e.g.,* addition of compressors or recycle lines).

(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) Connections made for flare gas sulfur removal.

(v) Connections made to install back-up (redundant) equipment associated with the flare (such as a back-up compressor) that does not increase the capacity of the flare.

(vi) 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.

(vii) Connections that interconnect two or more flares.

* * * * *

(d) For purposes of this subpart, under § 60.15, the "fixed capital cost of the new components" includes the fixed capital cost of all depreciable components which are or will be replaced pursuant to all continuous programs of component replacement which are commenced within any 2-year period following the relevant applicability date specified in paragraph (b) of this section.

■ 9. In § 60.101a, lift the stay on the definition of "flare" published December 22, 2008 (73 FR 78552).

■ 10. Section 60.101a is amended by:
■ a. Revising the introductory text;
■ b. Adding, in alphabetical order, definitions of "Air preheat," "Ancillary equipment," "Cascaded flare system," "Co-fired process heater," "Corrective action," "Corrective action analysis," "Emergency flare," "Flare gas header system," "Flare gas recovery system," "Forced draft process heater," "Natural draft process heater," "Non-emergency flare," "Primary flare," "Purge gas," "Root cause analysis," "Secondary flare," and "Sweep gas"; and
■ c. Revising the definitions of "Delayed coking unit," "Flare," "Flexicoking unit," "Fluid coking unit," "Fuel gas," "Fuel gas combustion device," "Petroleum refinery," "Process upset gas" and "Sulfur recovery plant"

The revisions and additions read as follows:

§ 60.101a Definitions.

Terms used in this subpart are defined in the Clean Air Act (CAA), in § 60.2 and in this section.

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 sensible heat of exhaust gas from the process heater.

Ancillary equipment means equipment used in conjunction with or that serve a refinery process unit. *Ancillary equipment* includes, but is not limited to, storage tanks, product loading operations, wastewater treatment systems, steam- or electricity-producing units (including coke gasification units), pressure relief valves, pumps, sampling vents and continuous analyzer vents.

Cascaded flare system means a series of flares connected to one flare gas header system arranged with increasing pressure set points so that discharges will be initially directed to the first flare in the series (*i.e.,* the primary flare). If the discharge pressure exceeds a set point at which the flow to the primary flare would exceed the primary flare's capacity, flow will be diverted to the second flare in the series. Similarly, flow would be diverted to a third (or fourth) flare if the pressure in the flare gas header system exceeds a threshold where the flow to the first two (or three) flares would exceed their capacities.

Co-fired process heater means a process heater that employs burners that are designed to be supplied by both gaseous and liquid fuels on a routine basis. Process heaters that have gas burners with emergency oil back-up burners are not considered co-fired process heaters.

* * * * *

Corrective action means the design, operation and maintenance changes that one takes consistent with good

engineering practice to reduce or eliminate the likelihood of the recurrence of the primary cause and any other contributing cause(s) of an event identified by a root cause analysis as having resulted in a discharge of gases to an affected flare in excess of specified thresholds.

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(s) is/are the best alternative(s), including, but not limited to, considerations of cost effectiveness, technical feasibility, safety and secondary impacts.

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* includes, but is not limited to, all of the coke drums associated with a single fractionator; the fractionator, including the bottoms receiver and the overhead condenser; the coke drum cutting water and quench system, including the jet pump and coker quench water tank; process piping and associated equipment such as pumps, valves and connectors; and the coke drum blowdown recovery compressor system.

Emergency flare means a flare that combusts gas exclusively released as a result of malfunctions (and not startup, shutdown, routine operations or any other cause) on four or fewer occasions in a rolling 365-day period. For purposes of this rule, a flare cannot be categorized as an *emergency flare* unless it maintains a water seal.

Flare means a combustion device that uses an uncontrolled volume of air to burn gases. The *flare* includes the foundation, flare tip, structural support, burner, igniter, flare controls, including air injection or steam injection systems, flame arrestors and the flare gas header system. In the case of an interconnected flare gas header system, the *flare* includes each individual flare serviced by the interconnected flare gas header system and the interconnected flare gas header system.

Flare gas header system means all piping and knockout pots, including those in a subheader system, used to collect and transport gas to a flare either from a process unit or a pressure relief valve from the fuel gas system, regardless of whether or not a flare gas recovery system draws gas from the *flare gas header system.* The *flare gas header system* includes piping inside the battery limit of a process unit if the purpose of the piping is to transport gas to a flare or knockout pot that is part of the flare.

Flare gas recovery system means a system of one or more compressors, piping and the 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.

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.

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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. For the purposes of this subpart, a process heater that uses fans at both the inlet air side and the exhaust air side (*i.e.,* balanced draft system) is considered to be a *forced draft process heater.*

Fuel gas means any gas which is generated at a petroleum refinery and which is combusted. *Fuel gas* includes natural gas when the natural gas is combined and 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 premium 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 in a thermal oxidizer or flare installed to control emissions from wastewater treatment units other than those processing sour water, marine tank vessel loading operations or asphalt processing units (*i.e.,* asphalt blowing stills).

Fuel gas combustion device means any equipment, such as process heaters and boilers, used to combust fuel gas. For the purposes of this subpart, *fuel gas combustion device* does not include flares or facilities in which gases are combusted to produce sulfur or sulfuric acid.

* * * * *

Natural draft process heater means any process heater in which the combustion air is supplied under ambient or negative 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, including induced draft systems.

Non-emergency flare means any flare that is not an emergency flare as defined in this subpart.

* * * * *

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.*

Primary flare means the first flare in a cascaded flare system.

* * * * *

Process upset gas means any gas generated by a petroleum refinery process unit or by ancillary equipment as a result of startup, shutdown, upset or malfunction.

Purge gas means gas introduced between a flare's water seal and a flare's tip to prevent oxygen infiltration (backflow) into the flare tip. For flares with no water seals, the function of *purge gas* is performed by sweep gas (*i.e.,* flares without water seals do not use *purge gas*).

* * * * *

Root cause analysis means an assessment conducted through a process of investigation to determine the primary cause, and any other contributing cause(s), of a discharge of gases in excess of specified thresholds.

Secondary flare means a flare in a cascaded flare system that provides additional flare capacity and pressure relief to a flare gas system when the flare gas flow exceeds the capacity of the primary flare. For purposes of this subpart, a *secondary flare* is characterized by infrequent use and must maintain a water seal.

* * * * *

Sulfur recovery plant means all process units which recover sulfur from H_2S and/or SO_2 from a common source of sour gas produced 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 or loading facilities 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 units 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.

Sweep gas means the gas introduced in a flare gas header system to maintain a constant flow of gas to prevent oxygen buildup in the flare header. For flares with no water seals, *sweep gas* also performs the function of preventing oxygen infiltration (backflow) into the flare tip.

■ 11. In § 60.102a, lift the stay on paragraph (g) published December 22, 2008 (73 FR 78552).

■ 12. Section 60.102a is amended by:
■ a. Revising paragraph (a);
■ b. Revising paragraph (f)(1)(ii);
■ c. Revising paragraph (g);
■ d. Removing and reserving paragraph (h); and
■ e. Revising paragraph (i).

The revisions 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 H_2S, each calculated as ppmv SO_2 (dry basis) at 0-percent excess air; or

* * * * *

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

(1) Except as provided in (g)(1)(iii) of this section, for each fuel gas combustion device, the owner or operator shall comply with either the emission limit in paragraph (g)(1)(i) of this section or the fuel gas concentration limit in paragraph (g)(1)(ii) of this section.

(i) The owner or operator shall not discharge or cause the discharge of any gases into the atmosphere that contain SO_2 in excess of 20 ppmv (dry basis, corrected to 0-percent excess air) determined hourly on a 3-hour rolling average basis and SO_2 in excess of 8 ppmv (dry basis, corrected to 0-percent excess air), determined daily on a 365 successive calendar day rolling average basis; or

(ii) The owner or operator shall not burn in any fuel gas combustion device any fuel gas that contains H_2S in excess of 162 ppmv determined hourly on a 3-hour rolling average basis and H_2S in excess of 60 ppmv determined daily on a 365 successive calendar day rolling average basis.

(iii) The combustion in a portable generator of fuel gas released as a result of tank degassing and/or cleaning is exempt from the emissions limits in paragraphs (g)(1)(i) and (ii) of this section.

(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 (iv) of this section.

(i) For each natural draft process heater, comply with the limit in either paragraph (g)(2)(i)(A) or (B) of this section. The owner or operator may comply with either limit at any time, provided that the appropriate parameters for each alternative are monitored as specified in § 60.107a; if fuel gas composition is not monitored as specified in § 60.107a(d), the owner or operator must comply with the concentration limits in paragraph (g)(2)(i)(A) of this section.

(A) 40 ppmv (dry basis, corrected to 0-percent excess air) determined daily on a 30-day rolling average basis; or

(B) 0.040 pounds per million British thermal units (lb/MMBtu) higher heating value basis determined daily on a 30-day rolling average basis.

(ii) For each forced draft process heater, comply with the limit in either paragraph (g)(2)(ii)(A) or (B) of this section. The owner or operator may comply with either limit at any time, provided that the appropriate parameters for each alternative are monitored as specified in § 60.107a; if fuel gas composition is not monitored as specified in § 60.107a(d), the owner or operator must comply with the concentration limits in paragraph (g)(2)(ii)(A) of this section.

(A) 60 ppmv (dry basis, corrected to 0-percent excess air) determined daily on a 30-day rolling average basis; or

(B) 0.060 lb/MMBtu higher heating value basis determined daily on a 30-day rolling average basis.

(iii) For each co-fired natural draft process heater, comply with the limit in either paragraph (g)(2)(iii)(A) or (B) of this section. The owner or operator must choose one of the emissions limits with which to comply at all times:

(A) 150 ppmv (dry basis, corrected to 0-percent excess air) determined daily on a 30 successive operating day rolling average basis; or

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

$$ER_{NOx} = \frac{0.06\,Q_{gas}\,HHV_{gas} + 0.35\,Q_{oil}\,HHV_{oil}}{Q_{gas}\,HHV_{gas} + Q_{oil}\,HHV_{oil}} \qquad \text{(Eq. 3)}$$

Where:

ER_{NOx} = Daily allowable average emission rate of NO_X, lb/MMBtu (higher heating value basis);

Q_{gas} = Daily average volumetric flow rate of fuel gas, standard cubic feet per day (scf/day);

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

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.

(iv) For each co-fired forced draft process heater, comply with the limit in either paragraph (g)(2)(iv)(A) or (B) of this section. The owner or operator must choose one of the emissions limits with which to comply at all times:

(A) 150 ppmv (dry basis, corrected to 0-percent excess air) determined daily on a 30 successive operating day rolling average basis; or

(B) The daily average emissions limit calculated using Equation 4 of this section:

$$ER_{NOx} = \frac{0.11 Q_{gas} HHV_{gas} + 0.40 Q_{oil} HHV_{oil}}{Q_{gas} HHV_{gas} + Q_{oil} HHV_{oil}} \quad \text{(Eq. 4)}$$

Where:

ER_{NOx} = Daily allowable average emission rate of NO_X, lb/MMBtu (higher heating value basis);

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

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

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.

(h) [Reserved]

(i) For a process heater that meets any of the criteria of paragraphs (i)(1)(i) through (iv) of this section, an owner or operator may request approval from the Administrator for a NO_X emissions limit which shall apply specifically to that affected facility. The request shall include information as described in paragraph (i)(2) of this section. The request shall be submitted and followed as described in paragraph (i)(3) of this section.

(1) A process heater that meets one of the criteria in paragraphs (i)(1)(i) through (iv) of this section may apply for a site-specific NO_X emissions limit:

(i) A modified or reconstructed process heater that lacks sufficient space to accommodate installation and proper operation of combustion modification-based technology (*e.g.,* ultra-low NO_X burners); or

(ii) A modified or reconstructed process heater that has downwardly firing induced draft burners; or

(iii) A co-fired process heater; or

(iv) A process heater operating at reduced firing conditions for an extended period of time (*i.e.,* operating in turndown mode). The site-specific NO_X emissions limit will only apply for those operating conditions.

(2) The request 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 emissions limit in paragraph (g)(2) of this section. At a minimum, the request shall contain the information described in paragraphs (i)(2)(i) through (iv) of this section.

(i) 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, information regarding the combustion conditions (temperature, oxygen content, firing rates) and other information needed to demonstrate that the process heater meets one of the four classes of process heaters listed in paragraph (i)(1) of this section.

(ii) An explanation of how the data in paragraph (i)(2)(i) demonstrate that ultra-low NO_X burners, flue gas recirculation, control of excess air or other combustion modification-based technology (including combinations of these combustion modification-based technologies) cannot be used to meet the applicable emissions limit in paragraph (g)(2) of this section.

(iii) 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.

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

(3) The request shall be submitted and followed as described in paragraphs (i)(3)(i) through (iii) of this section.

(i) The owner or operator of a process heater that meets one of the criteria in paragraphs (i)(1)(i) through (iv) of this section may request approval from the Administrator within 180 days after initial startup of the process heater for a NO_X emissions limit which shall apply specifically to that affected facility.

(ii) The request must be submitted to the Administrator for approval. The owner or operator must comply with the request as submitted until it is approved.

(iii) The request shall also be submitted to the following address: U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Sector Policies and Programs Division, U.S. EPA Mailroom (E143–01), Attention: Refinery Sector Lead, 109 T.W. Alexander Drive, Research Triangle Park, NC 27711. Electronic copies in lieu of hard copies may also be submitted to *refinerynsps@epa.gov*.

(4) The approval process for a request for a facility-specific NO_X emissions limit is described in paragraphs (i)(4)(i) through (iii) of this section.

(i) Approval by the Administrator of a facility-specific NO_X emissions limit request will be based on the completeness, accuracy and reasonableness of the request. Factors that the EPA will consider in reviewing the request for approval include, but are not limited to, the following:

(A) A demonstration that the process heater meets one of the four classes of process heaters outlined in paragraphs (i)(1) of this section;

(B) A description of the low-NO_X burner designs and other combustion modifications considered for reducing NO_X emissions;

(C) The combustion modification option selected; and

(D) The operating conditions (firing rate, heater box temperature and excess oxygen concentration) at which the NO_X emission level was established.

(ii) If the request is approved by the Administrator, a facility-specific NO_X emissions limit will be established at the NO_X emission level demonstrated in the approved request.

(iii) If the Administrator finds any deficiencies in the request, the request must be revised to address the deficiencies and be re-submitted for approval.

■ 13. Section 60.103a is revised to read as follows:

§ 60.103a Design, equipment, work practice or operational standards.

(a) Except as provided in paragraph (g) of this section, each owner or operator that operates a flare that is subject to this subpart shall develop and implement a written flare management plan no later than the date specified in paragraph (b) of this section. The flare management plan must include the information described in paragraphs (a)(1) through (7) of this section.

(1) A listing of all refinery process units, ancillary equipment, and fuel gas systems connected to the flare for each affected flare.

(2) An assessment of whether discharges to affected flares from these process units, ancillary equipment and fuel gas systems can be minimized. The flare minimization assessment must (at a minimum) consider the items in paragraphs (a)(2)(i) through (iv) of this section. The assessment must provide clear rationale in terms of costs (capital and annual operating), natural gas offset credits (if applicable), technical feasibility, secondary environmental impacts and safety considerations for the selected minimization alternative(s) or a statement, with justifications, that flow reduction could not be achieved. Based upon the assessment, each owner or operator of an affected flare shall identify the minimization alternatives that it has implemented by the due date of the flare management plan and shall include a schedule for the prompt implementation of any selected measures that cannot reasonably be completed as of that date.

(i) Elimination of process gas discharge to the flare through process operating changes or gas recovery at the source.

(ii) Reduction of the volume of process gas to the flare through process operating changes.

(iii) Installation of a flare gas recovery system or, for facilities that are fuel gas rich, a flare gas recovery system and a co-generation unit or combined heat and power unit.

(iv) Minimization of sweep gas flow rates and, for flares with water seals, purge gas flow rates.

(3) A description of each affected flare containing the information in paragraphs (a)(3)(i) through (vii) of this section.

(i) A general description of the flare, including the information in paragraphs (a)(3)(i)(A) through (G) of this section.

(A) Whether it is a ground flare or elevated (including height).

(B) The type of assist system (*e.g.,* air, steam, pressure, non-assisted).

(C) Whether it is simple or complex flare tip (*e.g.,* staged, sequential).

(D) Whether the flare is part of a cascaded flare system (and if so, whether the flare is primary or secondary).

(E) Whether the flare serves as a backup to another flare.

(F) Whether the flare is an emergency flare or a non-emergency flare.

(G) Whether the flare is equipped with a flare gas recovery system.

(ii) Description and simple process flow diagram showing the interconnection of the following components of the flare: flare tip (date installed, manufacturer, nominal and effective tip diameter, tip drawing); knockout or surge drum(s) or pot(s) (including dimensions and design capacities); flare header(s) and subheader(s); assist system; and ignition system.

(iii) Flare design parameters, including the maximum vent gas flow rate; minimum sweep gas flow rate; minimum purge gas flow rate (if any); maximum supplemental gas flow rate; maximum pilot gas flow rate; and, if the flare is steam-assisted, minimum total steam rate.

(iv) Description and simple process flow diagram showing all gas lines (including flare, purge (if applicable), sweep, supplemental and pilot gas) that are associated with the flare. For purge, sweep, supplemental and pilot gas, identify the type of gas used. Designate which lines are exempt from sulfur, H_2S or flow monitoring and why (*e.g.,* natural gas, inherently low sulfur, pilot gas). Designate which lines are monitored and identify on the process flow diagram the location and type of each monitor.

(v) For each flow rate, H_2S, sulfur content, pressure or water seal monitor identified in paragraph (a)(3)(iv) of this section, provide a detailed description of the manufacturer's specifications, including, but not limited to, make, model, type, range, precision, accuracy, calibration, maintenance and quality assurance procedures.

(vi) For emergency flares, secondary flares and flares equipped with a flare gas recovery system designed, sized and operated to capture all flows except those resulting from startup, shutdown or malfunction:

(A) Description of the water seal, including the operating range for the liquid level.

(B) Designation of the monitoring option elected (flow and sulfur monitoring or pressure and water seal liquid level monitoring).

(vii) For flares equipped with a flare gas recovery system:

(A) A description of the flare gas recovery system, including number of compressors and capacity of each compressor.

(B) A description of the monitoring parameters used to quantify the amount of flare gas recovered.

(C) For systems with staged compressors, the maximum time period required to begin gas recovery with the secondary compressor(s), the monitoring parameters and procedures used to minimize the duration of releases during compressor staging and a justification for why the maximum time period cannot be further reduced.

(4) An evaluation of the baseline flow to the flare. The baseline flow to the flare must be determined after implementing the minimization assessment in paragraph (a)(2) of this section. Baseline flows do not include pilot gas flow or purge gas flow (*i.e.,* gas introduced after the flare's water seal) provided these gas flows remain reasonably constant (*i.e.,* separate flow monitors for these streams are not required). Separate baseline flow rates may be established for different operating conditions provided that the management plan includes:

(i) A primary baseline flow rate that will be used as the default baseline for all conditions except those specifically delineated in the plan;

(ii) A description of each special condition for which an alternate baseline is established, including the rationale for each alternate baseline, the daily flow for each alternate baseline and the expected duration of the special conditions for each alternate baseline; and

(iii) Procedures to minimize discharges to the affected flare during each special condition described in paragraph (a)(4)(ii) of this section, unless procedures are already developed for these cases under paragraph (a)(5) through (7) of this section, as applicable.

(5) Procedures to minimize or eliminate discharges to the flare during the planned startup and shutdown of the refinery process units and ancillary equipment that are connected to the affected flare, together with a schedule for the prompt implementation of any procedures that cannot reasonably be implemented as of the date of the submission of the flare management plan.

(6) Procedures to reduce flaring in cases of fuel gas imbalance (*i.e.,* excess fuel gas for the refinery's energy needs), together with a schedule for the prompt implementation of any procedures that cannot reasonably be implemented as of the date of the submission of the flare management plan.

(7) For flares equipped with flare gas recovery systems, procedures to minimize the frequency and duration of outages of the flare gas recovery system and procedures to minimize the volume of gas flared during such outages, together with a schedule for the prompt implementation of any procedures that cannot reasonably be implemented as of the date of the submission of the flare management plan.

(b) Except as provided in paragraph (g) of this section, each owner or

operator required to develop and implement a written flare management plan as described in paragraph (a) of this section must submit the plan to the Administrator as described in paragraphs (b)(1) through (3) of this section.

(1) 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 the flare becomes an affected facility subject to this subpart, except for the selected minimization alternatives in paragraph (a)(2) and/or the procedures in paragraphs (a)(5) though (a)(7) of this section that cannot reasonably be implemented by that date, which the owner or operator must implement in accordance with the schedule in the flare management plan. The owner or operator of a modified flare must develop and implement the flare management plan by no later than November 11, 2015 or upon startup of the modified flare, whichever is later.

(2) The owner or operator must comply with the plan as submitted by the date specified in paragraph (b)(1) of this section. The plan should be updated periodically to account for changes in the operation of the flare, such as new connections to the flare or the installation of a flare gas recovery system, but the plan need be re-submitted to the Administrator only if the owner or operator adds an alternative baseline flow rate, revises an existing baseline as described in paragraph (a)(4) of this section, installs a flare gas recovery system or is required to change flare designations and monitoring methods as described in § 60.107a(g). The owner or operator must comply with the updated plan as submitted.

(3) All versions of the plan submitted to the Administrator shall also be submitted to the following address: U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Sector Policies and Programs Division, U.S. EPA Mailroom (E143–01), Attention: Refinery Sector Lead, 109 T.W. Alexander Drive, Research Triangle Park, NC 27711. Electronic copies in lieu of hard copies may also be submitted to *refinerynsps@epa.gov*.

(c) Except as provided in paragraphs (f) and (g) of this section, each owner or operator that operates a fuel gas combustion device, flare or sulfur recovery plant subject to this subpart shall conduct a root cause analysis and a corrective action analysis for each of the conditions specified in paragraphs (c)(1) through (3) of this section.

(1) For a flare:

(i) Any time the SO_2 emissions exceed 227 kilograms (kg) (500 lb) in any 24-hour period; or

(ii) Any discharge to the flare in excess of 14,160 standard cubic meters (m^3) (500,000 standard cubic feet (scf)) above the baseline, determined in paragraph (a)(4) of this section, in any 24-hour period; or

(iii) If the monitoring alternative in § 60.107a(g) is elected, any period when the flare gas line pressure exceeds the water seal liquid depth, except for periods attributable to compressor staging that do not exceed the staging time specified in paragraph (a)(3)(vii)(C) of this section.

(2) For a fuel gas combustion device, each exceedance of an applicable short-term emissions limit in § 60.102a(g)(1) if the SO_2 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 one or more consecutive periods of excess emissions or any 24-hour period, whichever is shorter.

(3) For a sulfur recovery plant, each time the SO_2 emissions are more than 227 kg (500 lb) greater than the amount that would have been emitted if the SO_2 or reduced sulfur concentration was equal to the applicable emissions limit in § 60.102a(f)(1) or (2) during one or more consecutive periods of excess emissions or any 24-hour period, whichever is shorter.

(d) Except as provided in paragraphs (f) and (g) of this section, a root cause analysis and corrective action analysis must be completed as soon as possible, but no later than 45 days after a discharge meeting one of the conditions specified in paragraphs (c)(1) through (3) of this section. Special circumstances affecting the number of root cause analyses and/or corrective action analyses are provided in paragraphs (d)(1) through (5) of this section.

(1) If a single continuous discharge meets any of the conditions specified in paragraphs (c)(1) through (3) of this section for 2 or more consecutive 24-hour periods, a single root cause analysis and corrective action analysis may be conducted.

(2) If a single discharge from a flare triggers a root cause analysis based on more than one of the conditions specified in paragraphs (c)(1)(i) through (iii) of this section, a single root cause analysis and corrective action analysis may be conducted.

(3) If the discharge from a flare is the result of a planned startup or shutdown of a refinery process unit or ancillary equipment connected to the affected flare and the procedures in paragraph (a)(5) of this section were followed, a root cause analysis and corrective action analysis is not required; however, the discharge must be recorded as described in § 60.108a(c)(6) and reported as described in § 60.108a(d)(5).

(4) If both the primary and secondary flare in a cascaded flare system meet any of the conditions specified in paragraphs (c)(1)(i) through (iii) of this section in the same 24-hour period, a single root cause analysis and corrective action analysis may be conducted.

(5) Except as provided in paragraph (d)(4) of this section, if discharges occur that meet any of the conditions specified in paragraphs (c)(1) through (3) of this section for more than one affected facility in the same 24-hour period, initial root cause analyses shall be conducted for each affected facility. If the initial root cause analyses indicate that the discharges have the same root cause(s), the initial root cause analyses can be recorded as a single root cause analysis and a single corrective action analysis may be conducted.

(e) Except as provided in paragraphs (f) and (g) of this section, each owner or operator of a fuel gas combustion device, flare or sulfur recovery plant subject to this subpart shall implement the corrective action(s) identified in the corrective action analysis conducted pursuant to paragraph (d) of this section in accordance with the applicable requirements in paragraphs (e)(1) through (3) of this section.

(1) All corrective action(s) must be implemented within 45 days of the discharge for which the root cause and corrective action analyses were required or as soon thereafter as practicable. 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 as specified in § 60.108a(c)(6)(ix).

(2) For corrective actions that cannot be fully implemented within 45 days following the discharge for which the root cause and corrective action analyses were required, the owner or operator shall develop an implementation schedule to complete the corrective action(s) as soon as practicable.

(3) No later than 45 days following the discharge for which a root cause and corrective action analyses were required, the owner or operator shall record the corrective action(s) completed to date, and, for action(s) not already completed, a schedule for implementation, including proposed commencement and completion dates as specified in § 60.108a(c)(6)(x).

(f) Modified flares shall comply with the requirements of paragraphs (c) through (e) of this section by November 11, 2015 or at startup of the modified flare, whichever is later. Modified flares that were not affected facilities subject to subpart J of this part prior to becoming affected facilities under § 60.100a shall comply with the requirements of paragraph (h) of this section and the requirements of § 60.107a(a)(2) by November 11, 2015 or at startup of the modified flare, whichever is later. Modified flares that were affected facilities subject to subpart J of this part prior to becoming affected facilities under § 60.100a shall comply with the requirements of paragraph (h) of this section and the requirements of § 60.107a(a)(2) by November 13, 2012 or at startup of the modified flare, whichever is later, except that modified flares that have accepted applicability of subpart J under a federal consent decree shall comply with the subpart J requirements as specified in the consent decree, but shall comply with the requirements of paragraph (h) of this section and the requirements of § 60.107a(a)(2) by no later than November 11, 2015.

(g) An affected flare subject to this subpart located in the Bay Area Air Quality Management District (BAAQMD) may elect to comply with both BAAQMD Regulation 12, Rule 11 and BAAQMD Regulation 12, Rule 12 as an alternative to complying with the requirements of paragraphs (a) through (e) of this section. An affected flare subject to this subpart located in the South Coast Air Quality Management District (SCAQMD) may elect to comply with SCAQMD Rule 1118 as an alternative to complying with the requirements of paragraphs (a) through (e) of this section. The owner or operator of an affected flare must notify the Administrator that the flare is in compliance with BAAQMD Regulation 12, Rule 11 and BAAQMD Regulation 12, Rule 12 or SCAQMD Rule 1118. The owner or operator of an affected flare shall also submit the existing flare management plan to the following address: U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Sector Policies and Programs Division, U.S. EPA Mailroom (E143–01), Attention: Refinery Sector Lead, 109 T.W. Alexander Drive, Research Triangle Park, NC 27711. Electronic copies in lieu of hard copies may also be submitted to *refinerynsps@epa.gov*.

(h) Each owner or operator shall not burn in any affected flare any fuel gas that contains H_2S in excess of 162 ppmv determined hourly on a 3-hour rolling average basis. The combustion in a flare of process upset gases or fuel gas that is released to the flare as a result of relief valve leakage or other emergency malfunctions is exempt from this limit.

(i) Each owner or operator of a delayed coking unit shall depressure each coke drum to 5 lb per square inch gauge (psig) or less prior to discharging the coke drum steam exhaust to the atmosphere. Until the coke drum pressure reaches 5 psig, the coke drum steam exhaust must be managed in an enclosed blowdown system and the uncondensed vapor must either be recovered (*e.g.,* sent to the delayed coking unit fractionators) or vented to the fuel gas system, a fuel gas combustion device or a flare.

(j) *Alternative means of emission limitation.* (1) Each owner or operator subject to the provisions of this section may apply to the Administrator for a determination of equivalence for any means of emission limitation that achieves a reduction in emissions of a specified pollutant at least equivalent to the reduction in emissions of that pollutant achieved by the controls required in this section.

(2) Determination of equivalence to the design, equipment, work practice or operational requirements of this section will be evaluated by the following guidelines:

(i) Each owner or operator applying for a determination of equivalence shall be responsible for collecting and verifying test data to demonstrate the equivalence of the alternative means of emission limitation.

(ii) For each affected facility for which a determination of equivalence is requested, the emission reduction achieved by the design, equipment, work practice or operational requirements shall be demonstrated.

(iii) For each affected facility for which a determination of equivalence is requested, the emission reduction achieved by the alternative means of emission limitation shall be demonstrated.

(iv) Each owner or operator applying for a determination of equivalence to a work practice standard shall commit in writing to work practice(s) that provide for emission reductions equal to or greater than the emission reductions achieved by the required work practice.

(v) The Administrator will compare the demonstrated emission reduction for the alternative means of emission limitation to the demonstrated emission reduction for the design, equipment, work practice or operational requirements and, if applicable, will consider the commitment in paragraph (j)(2)(iv) of this section.

(vi) The Administrator may condition the approval of the alternative means of emission limitation on requirements that may be necessary to ensure operation and maintenance to achieve the same emissions reduction as the design, equipment, work practice or operational requirements.

(3) An owner or operator may offer a unique approach to demonstrate the equivalence of any equivalent means of emission limitation.

(4) Approval of the application for equivalence to the design, equipment, work practice or operational requirements of this section will be evaluated by the following guidelines:

(i) After a request for determination of equivalence is received, the Administrator will publish a notice in the **Federal Register** and provide the opportunity for public hearing if the Administrator judges that the request may be approved.

(ii) After notice and opportunity for public hearing, the Administrator will determine the equivalence of a means of emission limitation and will publish the determination in the **Federal Register**.

(iii) Any equivalent means of emission limitations approved under this section shall constitute a required work practice, equipment, design or operational standard within the meaning of section 111(h)(1) of the CAA.

(5) Manufacturers of equipment used to control emissions may apply to the Administrator for determination of equivalence for any alternative means of emission limitation that achieves a reduction in emissions achieved by the equipment, design and operational requirements of this section. The Administrator will make an equivalence determination according to the provisions of paragraphs (j)(2) through (4) of this section.

■ 14. Section 60.104a is amended by:
■ a. Revising paragraph (a);
■ b. Revising paragraphs (d)(4)(ii), (d)(4)(iii), (d)(4)(v) and (d)(8);
■ c. Revising paragraph (f)(3);
■ d. Revising paragraph (h)(5)(iv);
■ e. Revising paragraph (i) introductory text;
■ f. Adding paragraphs (i)(6) through (i)(8);
■ g. Revising paragraph (j) introductory text and paragraph (j)(4) introductory text; and
■ h. Revising paragraph (j)(4)(iv) to read as follows:

§ 60.104a Performance tests.

(a) The owner or operator shall conduct a performance test for each FCCU, FCU, sulfur recovery plant, flare and fuel gas combustion device to

demonstrate initial compliance with each applicable emissions limit in § 60.102a according to the requirements of § 60.8. The notification requirements of § 60.8(d) apply to the initial performance test and to subsequent performance tests required by paragraph (b) of this section (or as required by the Administrator), but does not apply to performance tests conducted for the purpose of obtaining supplemental data because of continuous monitoring system breakdowns, repairs, calibration checks and zero and span adjustments.

* * * * *

(d) * * *

(4) * * *

(ii) The emissions rate of PM (E_{PM}) is computed for each run using Equation 5 of this section:

$$E = \frac{c_s Q_{sd}}{K R_c} \qquad \text{(Eq. 5)}$$

Where:

E = Emission rate of PM, g/kg (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 6 of this section:

$$R_c = K_1 Q_r (\%CO_2 + \%CO) + K_2 Q_a - K_3 Q_r \left(\%CO/2 + \%CO_2 + \%O_2\right) + K_3 Q_{oxy} (\%O_{oxy}) \qquad \text{(Eq. 6)}$$

Where:

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 O_2 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 (CO_2) 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);

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

$\%O_{oxy}$ = O_2 concentration in O_2 enriched air stream inlet to the FCCU regenerator or fluid coking burner, percent by volume (dry basis);

K_1 = Material balance and conversion factor, 0.2982 (kg-min)/(hr-dscm-%) [0.0186 (lb-min)/(hr-dscf-%)];

K_2 = Material balance and conversion factor, 2.088 (kg-min)/(hr-dscm) [0.1303 (lb-min)/(hr-dscf)]; and

K_3 = 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 7 of this section:

$$Q_r = \frac{79 \times Q_a + (100 - \%Oxy) \times Q_{oxy}}{100 - \%CO_2 - \%CO - \%O_2} \qquad \text{(Eq. 7)}$$

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 O_2 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(h)(3), assume %CO to be zero;

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

$\%O_{oxy}$ = O_2 concentration in O_2 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, SO_2 and CO pollutant concentrations to 0-percent excess air or 0-percent O_2 using Equation 8 of this section:

$$C_{adj} = C_{meas}\left[20.9_c \Big/ (20.9 - \%O_2)\right] \qquad \text{(Eq. 8)}$$

Where:

C_{adj} = pollutant concentration adjusted to 0-percent excess air or O_2, 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 O_2 − 0.0 percent O_2 (defined O_2 correction basis), percent;

20.9 = O_2 concentration in air, percent; and

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

* * * * *

(f) * * *

(3) Compute the site-specific limit using Equation 9 of this section:

$$Opacity\ \ Limit = Opacity_{st}\ x\left(\frac{1\,\text{lb}/1{,}000\ \text{lb coke burn}}{PMEmR_{st}}\right) \qquad \text{(Eq. 9)}$$

Where:

Opacity limit = Maximum permissible 3-hour average opacity, percent, or 10 percent, whichever is greater;

$Opacity_{st}$ = Hourly average opacity measured during the source test, percent; and

$PMEmR_{st}$ = PM emission rate measured during the source test, lb/1,000 lb coke burn.

* * * * *

(h) * * *

(5) * * *

(iv) The owner or operator shall use Equation 8 of this section to adjust pollutant concentrations to 0-percent O_2 or 0- percent excess air.

(i) The owner or operator shall determine compliance with the SO_2 and NO_X emissions limits in § 60.102a(g) for a fuel gas combustion device according to the following test methods and procedures:

* * * * *

(6) For process heaters with a rated heat capacity between 40 and 100 MMBtu/hr that elect to demonstrate continuous compliance with a maximum excess oxygen limit as provided in § 60.107a(c)(6) or (d)(8), the owner or operator shall establish the O_2 operating limit or O_2 operating curve based on the performance test results according to the requirements in paragraph (i)(6)(i) or (ii) of this section, respectively.

(i) If a single O_2 operating limit will be used:

(A) Conduct the performance test following the methods provided in paragraphs (i)(1), (2), (3) and (5) of this section when the process heater is firing at no less than 70 percent of the rated heat capacity. For co-fired process heaters, conduct at least one of the test runs while the process heater is being supplied by both fuel gas and fuel oil and conduct at least one of the test runs while the process heater is being supplied solely by fuel gas.

(B) Each test will consist of three test runs. Calculate the NO_X concentration for the performance test as the average of the NO_X concentrations from each of the three test runs. If the NO_X concentration for the performance test is less than or equal to the numerical value of the applicable NO_X emissions limit (regardless of averaging time), then the test is considered to be a valid test.

(C) Determine the average O_2 concentration for each test run of a valid test.

(D) Calculate the O_2 operating limit as the average O_2 concentration of the three test runs from a valid test.

(ii) If an O_2 operating curve will be used:

(A) Conduct a performance test following the methods provided in paragraphs (i)(1), (2), (3) and (5) of this section at a representative condition for each operating range for which different O_2 operating limits will be established. Different operating conditions may be defined as different firing rates (*e.g.,* above 50 percent of rated heat capacity and at or below 50 percent of rated heat capacity) and/or, for co-fired process heaters, different fuel mixtures (*e.g.,* primarily gas fired, primarily oil fired, and equally co-fired, *i.e.,* approximately 50 percent of the input heating value is from fuel gas and approximately 50 percent of the input heating value is from fuel oil). Performance tests for different operating ranges may be conducted at different times.

(B) Each test will consist of three test runs. Calculate the NO_X concentration for the performance test as the average of the NO_X concentrations from each of the three test runs. If the NO_X concentration for the performance test is less than or equal to the numerical value of the applicable NO_X emissions limit (regardless of averaging time), then the test is considered to be a valid test.

(C) If an operating curve is developed for different firing rates, conduct at least one test when the process heater is firing at no less than 70 percent of the rated heat capacity and at least one test under turndown conditions (*i.e.,* when the process heater is firing at 50 percent or less of the rated heat capacity). If O_2 operating limits are developed for co-fired process heaters based only on overall firing rates (and not by fuel mixtures), conduct at least one of the test runs for each test while the process heater is being supplied by both fuel gas and fuel oil and conduct at least one of the test runs while the process heater is being supplied solely by fuel gas.

(D) Determine the average O_2 concentration for each test run of a valid test.

(E) Calculate the O_2 operating limit for each operating range as the average O_2 concentration of the three test runs from a valid test conducted at the representative conditions for that given operating range.

(F) Identify the firing rates for which the different operating limits apply. If only two operating limits are established based on firing rates, the O_2 operating limits established when the process heater is firing at no less than 70 percent of the rated heat capacity must apply when the process heater is firing above 50 percent of the rated heat capacity and the O_2 operating limits established for turndown conditions must apply when the process heater is firing at 50 percent or less of the rated heat capacity.

(G) Operating limits associated with each interval will be valid for 2 years or until another operating limit is established for that interval based on a more recent performance test specific for that interval, whichever occurs first. Owners and operators must use the operating limits determined for a given interval based on the most recent performance test conducted for that interval.

(7) The owner or operator of a process heater complying with a NO_X limit in terms of lb/MMBtu as provided in § 60.102a(g)(2)(i)(B), (g)(2)(ii)(B), (g)(2)(iii)(B) or (g)(2)(iv)(B) or a process heater with a rated heat capacity between 40 and 100 MMBtu/hr that

elects to demonstrate continuous compliance with a maximum excess O_2 limit, as provided in § 60.107a(c)(6) or (d)(8), shall determine heat input to the process heater in MMBtu/hr during each performance test run by measuring fuel gas flow rate, fuel oil flow rate (as applicable) and heating value content according to the methods provided in § 60.107a(d)(5), (d)(6), and (d)(4) or (d)(7), respectively.

(8) The owner or operator shall use Equation 8 of this section to adjust pollutant concentrations to 0-percent O_2 or 0- percent excess air.

(j) The owner or operator shall determine compliance with the applicable H_2S emissions limit in § 60.102a(g)(1) for a fuel gas combustion device or the concentration requirement in § 60.103a(h) for a flare according to the following test methods and procedures:

* * * * *

(4) EPA Method 11, 15 or 15A of Appendix A–5 to part 60 or EPA Method 16 of Appendix A–6 to part 60 for determining the H_2S concentration for affected facilities using an H_2S monitor as specified in § 60.107a(a)(2). The method ANSI/ASME PTC 19.10–1981 (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 15A of Appendix A–5 to part 60. The owner or operator may demonstrate compliance based on the mixture used in the fuel gas combustion device or flare or for each individual fuel gas stream used in the fuel gas combustion device or flare.

* * * * *

(iv) If monitoring is conducted at a single point in a common source of fuel gas as allowed under § 60.107a(a)(2)(iv), only one performance test is required. That is, performance tests are not required when a new affected fuel gas combustion device or flare is added to a common source of fuel gas that previously demonstrated compliance.

■ 15. Section 60.105a is amended by:

■ a. Revising paragraph (b) introductory text, and paragraph (b)(1) introductory text, and paragraphs (b)(1)(ii)(A), (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) that uses a control device other than fabric filter or cyclone shall comply with the requirements in paragraphs (b)(1) and (2) of this section.

(1) The owner or operator shall install, operate and maintain continuous parameter monitor systems (CPMS) to measure and record operating parameters for each control device according to the applicable requirements in paragraphs (b)(1)(i) through (v) of this section.

* * * * *

(ii) * * *

(A) As an alternative to pressure drop, the owner or operator of a jet ejector type wet scrubber or other type of wet scrubber equipped with atomizing spray nozzles must conduct a daily check of the air or water pressure to the spray nozzles and record the results of each check.

* * * * *

(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 CO_2, O_2 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 EPA Method 3 of Appendix A–3 to part 60 and EPA 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 SO_2 as measured by the SO_2 CEMS under § 60.105a(g) exceeds 50 ppmv, and all rolling 365-day periods during which the average concentration of SO_2 as measured by the SO_2 CEMS exceeds 25 ppmv.

* * * * *

■ 16. In § 60.107a, lift the stay on paragraphs (d) and (e) published December 22, 2008 (73 FR 78552).

■ 17. Section 60.107a is amended by:

■ a. Revising the section heading;

■ b. Revising paragraph (a) introductory text, paragraph (a)(1) introductory text, paragraph (a)(2) introductory text, (a)(2)(i), (a)(2)(iv) and paragraph (a)(3) introductory text;

■ c. Adding paragraphs (a)(2)(v) and (a)(2)(vi);

■ d. Revising paragraph (b) introductory text and paragraphs (b)(1)(i), (b)(1)(v) and (b)(3)(iii);

■ e. Revising paragraph (c) introductory text and paragraphs (c)(1) and (c)(6);

■ f. Redesignating paragraphs (d), (e), and (f) as paragraphs (e), (f) and (i), respectively;

■ g. Adding a new paragraph (d);

■ h. Revising newly redesignated paragraph (e);

■ i. Revising newly redesignated paragraph (f);

■ j. Adding a new paragraph (g);

■ k. Adding a new paragraph (h); and

■ l. Revising newly redesignated paragraph (i).

The revisions and additions read as follows:

§ 60.107a Monitoring of emissions and operations for fuel gas combustion devices and flares.

(a) *Fuel gas combustion devices subject to* SO_2 or H_2S limit and flares subject to H_2S concentration requirements. The owner or operator of a fuel gas combustion device that is subject to § 60.102a(g)(1) and elects to comply with the SO_2 emission limits in § 60.102a(g)(1)(i) shall comply with the requirements in paragraph (a)(1) of this section. The owner or operator of a fuel gas combustion device that is subject to § 60.102a(g)(1) and elects to comply with the H_2S concentration limits in § 60.102a(g)(1)(ii) or a flare that is subject to the H_2S concentration requirement in § 60.103a(h) shall comply with paragraph (a)(2) of this section.

(1) The owner or operator of a fuel gas combustion device that elects to comply with the SO_2 emissions limits in § 60.102a(g)(1)(i) shall install, operate, calibrate and maintain an instrument for continuously monitoring and recording the concentration (dry basis, 0-percent excess air) of SO_2 emissions into the atmosphere. The monitor must include an O_2 monitor for correcting the data for excess air.

* * * * *

(2) The owner or operator of a fuel gas combustion device that elects to comply with the H_2S concentration limits in § 60.102a(g)(1)(ii) or a flare that is subject to the H_2S concentration requirement in § 60.103a(h) shall install, operate, calibrate and maintain an instrument for continuously monitoring and recording the concentration by volume (dry basis) of H_2S in the fuel gases before being burned in any fuel gas combustion device or flare.

(i) The owner or operator shall install, operate and maintain each H_2S monitor according to Performance Specification 7 of Appendix B to part 60. The span value for this instrument is 300 ppmv H_2S.

* * * * *

(iv) Fuel gas combustion devices or flares having a common source of fuel gas may be monitored at only one location, if monitoring at this location accurately represents the concentration

of H_2S in the fuel gas being burned in the respective fuel gas combustion devices or flares.

(v) The owner or operator of a flare subject to § 60.103a(c) through (e) may use the instrument required in paragraph (e)(1) of this section to demonstrate compliance with the H_2S concentration requirement in § 60.103a(h) if the owner or operator complies with the requirements of paragraph (e)(1)(i) through (iv) and if the instrument has a span (or dual span, if necessary) capable of accurately measuring concentrations between 20 and 300 ppmv. If the instrument required in paragraph (e)(1) of this section is used to demonstrate compliance with the H_2S concentration requirement, the concentration directly measured by the instrument must meet the numeric concentration in § 60.103a(h).

(vi) The owner or operator of modified flare that meets all three criteria in paragraphs (a)(2)(vi)(A) through (C) of this section shall comply with the requirements of paragraphs (a)(2)(i) through (v) of this section no later than November 11, 2015. The owner or operator shall comply with the approved alternative monitoring plan or plans pursuant to § 60.13(i) until the flare is in compliance with requirements of paragraphs (a)(2)(i) through (v) of this section.

(A) The flare was an affected facility subject to subpart J of this part prior to becoming an affected facility under § 60.100a.

(B) The owner or operator had an approved alternative monitoring plan or plans pursuant to § 60.13(i) for all fuel gases combusted in the flare.

(C) The flare did not have in place on or before September 12, 2012 an instrument for continuously monitoring and recording the concentration by volume (dry basis) of H_2S in the fuel gases that is capable of complying with the requirements of paragraphs (a)(2)(i) through (v) of this section.

(3) The owner or operator of a fuel gas combustion device or flare is not required to comply with paragraph (a)(1) or (2) of this section for fuel gas streams that are exempt under §§ 60.102a(g)(1)(iii) or 60.103a(h) or, for fuel gas streams combusted in a process heater, other fuel gas combustion device or flare that are inherently low in sulfur content. Fuel gas streams meeting one of the requirements in paragraphs (a)(3)(i) through (iv) of this section will be considered inherently low in sulfur content.

* * * * *

(b) *Exemption from H_2S monitoring requirements for low-sulfur fuel gas streams.* The owner or operator of a fuel gas combustion device or flare may apply for an exemption from the H_2S monitoring requirements in paragraph (a)(2) of this section for a fuel gas stream that is inherently low in sulfur content. A fuel gas stream that is demonstrated to be low-sulfur is exempt from the monitoring requirements of paragraphs (a)(1) and (2) of this section until there are changes in operating conditions or stream composition.

(1) * * *

(i) A description of the fuel gas stream/system to be considered, including submission of a portion of the appropriate piping diagrams indicating the boundaries of the fuel gas stream/system and the affected fuel gas combustion device(s) or flare(s) to be considered;

* * * * *

(v) A description of how the 2 weeks (or seven samples for infrequently operated fuel gas streams/systems) of monitoring results compares to the typical range of H_2S concentration (fuel quality) expected for the fuel gas stream/system going to the affected fuel gas combustion device or flare (*e.g.,* the 2 weeks of daily detector tube results for a frequently operated loading rack included the entire range of products loaded out and, therefore, should be representative of typical operating conditions affecting H_2S content in the fuel gas stream going to the loading rack flare).

* * * * *

(3) * * *

(iii) If the operation change results in a sulfur content that is outside the range of concentrations included in the original application and the owner or operator chooses not to submit new information to support an exemption, the owner or operator must begin H_2S monitoring using daily stain sampling to demonstrate compliance. The owner or operator must begin monitoring according to the requirements in paragraphs (a)(1) or (a)(2) of this section as soon as practicable, but in no case later than 180 days after the operation change. During daily stain tube sampling, a daily sample exceeding 162 ppmv is an exceedance of the 3-hour H_2S concentration limit. The owner or operator of a fuel gas combustion device must also determine a rolling 365-day average using the stain sampling results; an average H_2S concentration of 5 ppmv must be used for days within the rolling 365-day period prior to the operation change.

(c) *Process heaters complying with the NO_X concentration-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)(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 O_2 monitor for correcting the data for excess air.

(1) Except as provided in paragraph (c)(6) of this section, 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 emissions 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 according to the requirements in § 60.104a(i), establish a maximum excess O_2 operating limit or operating curve according to the requirements in § 60.104a(i)(6) and comply with the O_2 monitoring requirements in paragraphs (c)(3) through (5) of this section to demonstrate compliance. If an O_2 operating curve is used (*i.e.,* if different O_2 operating limits are established for different operating ranges), the owner or operator of the process heater must also monitor fuel gas flow rate, fuel oil flow rate (as applicable) and heating value content according to the methods provided in paragraphs (d)(5), (d)(6), and (d)(4) or (d)(7) of this section, respectively.

(d) *Process heaters complying with the NO_X heating value-based or mass-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) or (g)(2)(ii)(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 emissions limit in § 60.102a(g)(2) and electing to comply with the heating value-based limit in § 60.102a(g)(2)(iii)(B) or (g)(2)(iv)(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 according to the monitoring requirements in paragraph (d)(1) of this section; install, operate, calibrate and maintain an instrument for continuously monitoring and recording the flow rate of the fuel gas and fuel oil fed to the process heater according to the monitoring requirements in paragraph (d)(5) and (6) of this section; for fuel gas streams, determine gas composition according to the requirements in paragraph (d)(4) of this section or the higher heating value according to the requirements in paragraph (d)(7) of this section; and for fuel oil streams, determine the heating value according to the monitoring requirements in paragraph (d)(7) of this section.

(1) Except as provided in paragraph (d)(8) of this section, 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 O_2 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 EPA 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 10 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).

$$F_d = \frac{1{,}000{,}000 \times \sum (X_i \times MEV_i)}{\sum (X_i \times MHC_i)} \qquad \text{(Eq. 10)}$$

Where:

F_d = F factor on dry basis at 0-percent excess air, dscf/MMBtu.

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. Any of the following methods shall be used for conducting the relative accuracy evaluations:

(i) EPA Method 18 of Appendix A–6 to part 60;

(ii) ASTM D1945–03 (Reapproved 2010)(incorporated by reference-see § 60.17);

(iii) ASTM D1946–90 (Reapproved 2006)(incorporated by reference-see § 60.17);

(iv) ASTM D6420–99 (Reapproved 2004)(incorporated by reference-see § 60.17);

(v) GPA 2261–00 (incorporated by reference-see § 60.17); or

(vi) ASTM UOP539–97 (incorporated by reference-see § 60.17).

(5) The owner or operator shall install, operate and maintain fuel gas flow monitors according to the manufacturer's recommendations. For volumetric flow meters, temperature and pressure monitors must be installed in conjunction with the flow meter or in a representative location to correct the measured flow to standard conditions (*i.e.,* 68 °F and 1 atmosphere). For mass flow meters, use gas compositions determined according to paragraph (d)(4) of this section to determine the average molecular weight of the fuel gas and convert the mass flow to a volumetric flow at standard conditions (*i.e.,* 68 °F and 1 atmosphere). The owner or operator shall conduct performance evaluations of each fuel gas flow monitor according to the requirements in § 60.13 and Performance Specification 6 of Appendix B to part 60. Any of the following methods shall be used for conducting the relative accuracy evaluations:

(i) EPA Method 2, 2A, 2B, 2C or 2D of Appendix A–2 to part 60;

(ii) ASME MFC–3M–2004 (incorporated by reference-see § 60.17);

(iii) ANSI/ASME MFC–4M–1986 (Reaffirmed 2008) (incorporated by reference-see § 60.17);

(iv) ASME MFC–6M–1998 (Reaffirmed 2005) (incorporated by reference-see § 60.17);

(v) ASME/ANSI MFC–7M–1987 (Reaffirmed 2006) (incorporated by reference-see § 60.17);

(vi) ASME MFC–11M–2006 (incorporated by reference-see § 60.17);

(vii) ASME MFC–14M–2003 (incorporated by reference-see § 60.17);

(viii) ASME MFC–18M–2001 (incorporated by reference-see § 60.17);

(ix) AGA Report No. 3, Part 1 (incorporated by reference-see § 60.17);

(x) AGA Report No. 3, Part 2 (incorporated by reference-see § 60.17);

(xi) AGA Report No. 11 (incorporated by reference-see § 60.17);

(xii) AGA Report No. 7 (incorporated by reference-see § 60.17); and

(xiii) API Manual of Petroleum Measurement Standards, Chapter 22, Section 2 (incorporated by reference-see § 60.17).

(6) The owner or operator shall install, operate and maintain each fuel oil flow monitor according to the manufacturer's recommendations. The owner or operator shall conduct performance evaluations of each fuel oil flow monitor according to the requirements in § 60.13 and Performance Specification 6 of Appendix B to part 60. Any of the following methods shall be used for conducting the relative accuracy evaluations:

(i) Any one of the methods listed in paragraph (d)(5) of this section that are applicable to fuel oil (*i.e.,* ''fluids'');

(ii) ANSI/ASME–MFC–5M–1985 (Reaffirmed 2006) (incorporated by reference-see § 60.17);

(iii) ASME/ANSI MFC–9M–1988 (Reaffirmed 2006) (incorporated by reference-see § 60.17);

(iv) ASME MFC–16–2007 (incorporated by reference-see § 60.17);

(v) ASME MFC–22–2007 (incorporated by reference-see § 60.17); or

(vi) ISO 8316 (incorporated by reference-see § 60.17).

(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 (ix) 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). The higher heating value of each fuel fed to the process heater must be determined no less frequently than once per day except as provided in paragraph (d)(7)(x) of this section.

(i) ASTM D240–02 (Reapproved 2007) (incorporated by reference-see § 60.17).

(ii) ASTM D1826–94 (Reapproved 2003) (incorporated by reference-see § 60.17).

(iii) ASTM D1945–03 (Reapproved 2010) (incorporated by reference-see § 60.17).

(iv) ASTM D1946–90 (Reapproved 2006) (incorporated by reference-see § 60.17).

(v) ASTM D3588–98 (Reapproved 2003) (incorporated by reference-see § 60.17).

(vi) ASTM D4809–06 (incorporated by reference-see § 60.17).

(vii) ASTM D4891–89 (Reapproved 2006) (incorporated by reference-see § 60.17).

(viii) GPA 2172–09 (incorporated by reference-see § 60.17).

(ix) Any of the methods specified in section 2.2.7 of Appendix D to part 75.

(x) If the fuel oil supplied to the affected co-fired process heater originates from a single storage tank, the owner or operator may elect to use the storage tank sampling method in section 2.2.4.2 of Appendix D to part 75 instead of daily sampling, except that the most recent value for heating content must be used.

(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 according to the requirements in § 60.104a(i), establish a maximum excess O_2 operating limit or operating curve according to the requirements in § 60.104a(i)(6) and comply with the O_2 monitoring requirements in paragraphs (c)(3) through (5) of this section to demonstrate compliance. If an O_2 operating curve is used (*i.e.,* if different O_2 operating limits are established for different operating ranges), the owner or operator of the process heater must also monitor fuel gas flow rate, fuel oil flow rate (as applicable) and heating value content according to the methods provided in paragraphs (d)(5), (d)(6), and (d)(4) or (d)(7) of this section, respectively.

(e) *Sulfur monitoring for assessing root cause analysis threshold for affected flares.* Except as described in paragraphs (e)(4) and (h) of this section, the owner or operator of an affected flare subject to § 60.103a(c) through (e) shall determine the total reduced sulfur concentration for each gas line directed to the affected flare in accordance with either paragraph (e)(1), (e)(2) or (e)(3) of this section. Different options may be elected for different gas lines. If a monitoring system is in place that is capable of complying with the requirements related to either paragraph (e)(1), (e)(2) or (e)(3) of this section, the owner or operator of a modified flare must comply with the requirements related to either paragraph (e)(1), (e)(2) or (e)(3) of this section upon startup of the modified flare. If a monitoring system is not in place that is capable of complying with the requirements related to either paragraph (e)(1), (e)(2) or (e)(3) of this section, the owner or operator of a modified flare must comply with the requirements related to either paragraph (e)(1), (e)(2) or (e)(3) of this section no later than November 11, 2015 or upon startup of the modified flare, whichever is later.

(1) *Total reduced sulfur monitoring requirements.* The owner or operator shall install, operate, calibrate and maintain an instrument for continuously monitoring and recording the concentration of total reduced sulfur in gas discharged to the flare.

(i) The owner or operator shall install, operate and maintain each total reduced sulfur monitor according to Performance Specification 5 of Appendix B to part 60. The span value should be determined based on the maximum sulfur content of gas that can be discharged to the flare (*e.g.,* roughly 1.1 to 1.3 times the maximum anticipated sulfur concentration), but may be no less than 5,000 ppmv. A single dual range 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 total reduced sulfur monitor according to the requirements in § 60.13(c) and Performance Specification 5 of Appendix B to part 60. For flares that routinely have flow, the owner or operator of each total reduced sulfur monitor shall use EPA Method 15A of Appendix A–5 to part 60 for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10–1981 (incorporated by reference-see § 60.17) is an acceptable alternative to EPA Method 15A of Appendix A–5 to part 60. The alternative relative accuracy procedures described in section 16.0 of Performance Specification 2 of Appendix B to part 60 (cylinder gas audits) may be used for conducting the relative accuracy evaluations. For flares that do not receive routine flow, the alternative relative accuracy procedures described in section 16.0 of Performance Specification 2 of Appendix B to part 60 (cylinder gas audits) may be used for conducting the relative accuracy evaluations, except that it is not necessary to include as much of the sampling probe or sampling line as practical.

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

(2) *H_2S monitoring requirements.* The owner or operator shall install, operate, calibrate, and maintain an instrument for continuously monitoring and recording the concentration of H_2S in gas discharged to the flare according to the requirements in paragraphs (e)(2)(i) through (iii) of this section and shall collect and analyze samples of the gas and calculate total sulfur concentrations as specified in paragraphs (e)(2)(iv) through (ix) of this section.

(i) The owner or operator shall install, operate and maintain each H_2S monitor according to Performance Specification 7 of Appendix B to part 60. The span value should be determined based on the maximum sulfur content of gas that can be discharged to the flare (*e.g.,* roughly 1.1 to 1.3 times the maximum anticipated sulfur concentration), but may be no less than 5,000 ppmv. A single dual range H_2S 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 H_2S monitor according to the requirements in § 60.13(c) and Performance Specification 7 of Appendix B to part 60. For flares that routinely have flow, the owner or operator shall use EPA 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 (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 15A of Appendix A–5 to part 60. The alternative relative accuracy procedures described in section 16.0 of Performance Specification 2 of Appendix B to part 60 (cylinder gas audits) may be used for conducting the relative accuracy evaluations. For flares that do not receive routine flow, the alternative relative accuracy procedures described in section 16.0 of Performance Specification 2 of Appendix B to part 60 (cylinder gas audits) may be used for conducting the relative accuracy evaluations, except that it is not necessary to include as much of the sampling probe or sampling line as practical.

(iii) The owner or operator shall comply with the applicable quality assurance procedures in Appendix F to part 60 for each H_2S monitor.

(iv) In the first 10 operating days after the date the flare must begin to comply with § 60.103a(c)(1), the owner or operator shall collect representative daily samples of the gas discharged to the flare. 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)(2)(ix) of this section.

(v) The owner or operator shall analyze each daily sample for total sulfur using either EPA Method 15A of Appendix A–5 to part 60, EPA Method 16A of Appendix A–6 to part 60, ASTM Method D4468–85 (Reapproved 2006) (incorporated by reference—see § 60.17) or ASTM Method D5504–08 (incorporated by reference—see § 60.17).

(vi) The owner or operator shall develop a 10-day average total sulfur-to-H_2S ratio and 95-percent confidence interval as follows:

(A) Calculate the ratio of the total sulfur concentration to the H_2S concentration for each day during which samples are collected.

(B) Determine the 10-day average total sulfur-to-H_2S ratio as the arithmetic average of the daily ratios calculated in paragraph (e)(2)(vi)(A) of this section.

(C) Determine the acceptable range for subsequent weekly samples based on the 95-percent confidence interval for the distribution of daily ratios based on the 10 individual daily ratios using Equation 11 of this section.

$$AR = Ratio_{Avg} \pm 2.262 \times SDev \qquad \text{(Eq. 11)}$$

Where:

AR = Acceptable range of subsequent ratio determinations, unitless.

$Ratio_{Avg}$ = 10-day average total sulfur-to-H_2S concentration ratio, unitless.

2.262 = t-distribution statistic for 95-percent 2-sided confidence interval for 10 samples (9 degrees of freedom).

SDev = Standard deviation of the 10 daily average total sulfur-to-H_2S concentration ratios used to develop the 10-day average total sulfur-to-H_2S concentration ratio, unitless.

(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-H_2S ratio by the daily average H_2S concentrations obtained using the monitor as required by paragraph (e)(2)(i) through (iii) of this section to estimate total sulfur concentrations.

(ix) If the total sulfur-to-H_2S ratio for a subsequent weekly sample is outside the acceptable range for the most recent distribution of daily ratios, the owner or operator shall develop a new 10-day average ratio and acceptable range based on data for the outlying weekly sample plus data collected over the following 9 operating days.

(3) *SO_2 monitoring requirements.* The owner or operator shall install, operate, calibrate and maintain an instrument for continuously monitoring and recording the concentration of SO_2 from a process heater or other fuel gas combustion device that is combusting gas representative of the fuel gas in the flare gas line according to the requirements in paragraph (a)(1) of this section, determine the F factor of the fuel gas at least daily according to the requirements in paragraphs (d)(2) through (4) of this section, determine the higher heating value of the fuel gas at least daily according to the requirements in paragraph (d)(7) of this section and calculate the total sulfur content (as SO_2) in the fuel gas using Equation 12 of this section.

$$TS_{FG} = C_{SO_2} \times F_d \times HHV_{FG} \qquad \text{(Eq. 12)}$$

Where:

TS_{FG} = Total sulfur concentration, as SO_2, in the fuel gas, ppmv.

C_{SO2} = Concentration of SO_2 in the exhaust gas, ppmv (dry basis at 0-percent excess air).

F_d = F factor gas on dry basis at 0-percent excess air, dscf/MMBtu.

HHV_{FG} = Higher heating value of the fuel gas, MMBtu/scf.

(4) *Exemptions from sulfur monitoring requirements.* Flares identified in paragraphs (e)(4)(i) through (iv) of this section are exempt from the requirements in paragraphs (e)(1) through (3) of this section. For each such flare, except as provided in paragraph (e)(4)(iv), engineering calculations shall be used to calculate the SO_2 emissions in the event of a discharge that may trigger a root cause analysis under § 60.103a(c)(1).

(i) Flares that can only receive:

(A) Fuel gas streams that are inherently low in sulfur content as described in paragraph (a)(3)(i) through (iv) of this section; and/or

(B) Fuel gas streams that are inherently low in sulfur content for which the owner or operator has applied for an exemption from the H_2S monitoring requirements as described in paragraph (b) of this section.

(ii) Emergency flares, provided that for each such flare, the owner or operator complies with the monitoring alternative in paragraph (g) of this section.

(iii) Flares equipped with flare gas recovery systems designed, sized and operated to capture all flows except those resulting from startup, shutdown or malfunction, provided that for each such flare, the owner or operator complies with the monitoring alternative in paragraph (g) of this section.

(iv) Secondary flares that receive gas diverted from the primary flare. In the event of a discharge from the secondary flare, the sulfur content measured by the sulfur monitor on the primary flare should be used to calculate SO_2 emissions, regardless of whether or not the monitoring alternative in paragraph (g) of this section is selected for the secondary flare.

(f) *Flow monitoring for flares.* Except as provided in paragraphs (f)(2) and (h) of this section, the owner or operator of an affected flare subject to § 60.103a(c) through (e) shall install, operate, calibrate and maintain, in accordance with the specifications in paragraph (f)(1) of this section, a CPMS to measure and record the flow rate of gas discharged to the flare. If a flow monitor is not already in place, the owner or operator of a modified flare shall comply with the requirements of this paragraph by no later than November 11, 2015 or upon startup of the modified flare, whichever is later.

(1) The owner or operator shall install, calibrate, operate and maintain each flow monitor according to the manufacturer's procedures and specifications and the following requirements.

(i) Locate the monitor in a position that provides a representative measurement of the total gas flow rate.

(ii) Use a flow sensor with a measurement sensitivity of no more than 5 percent of the flow rate or 10 cubic feet per minute, whichever is greater.

(iii) Use a flow monitor that is maintainable online, is able to continuously correct for temperature and pressure and is able to record flow in standard conditions (as defined in § 60.2) over one-minute averages.

(iv) At least quarterly, perform a visual inspection of all components of the monitor for physical and operational integrity and all electrical connections for oxidation and galvanic corrosion if the flow monitor is not equipped with a redundant flow sensor.

(v) Recalibrate the flow monitor in accordance with the manufacturer's procedures and specifications biennially (every two years) or at the frequency specified by the manufacturer.

(2) Emergency flares, secondary flares and flares equipped with flare gas recovery systems designed, sized and operated to capture all flows except those resulting from startup, shutdown or malfunction are not required to install continuous flow monitors; provided, however, that for any such flare, the owner or operator shall comply with the monitoring alternative in paragraph (g) of this section.

(g) *Alternative monitoring for certain flares equipped with water seals.* The owner or operator of an affected flare subject to § 60.103a(c) through (e) that can be classified as either an emergency flare, a secondary flare or a flare equipped with a flare gas recovery system designed, sized and operated to capture all flows except those resulting from startup, shutdown or malfunction may, as an alternative to the sulfur and flow monitoring requirements of paragraphs (e) and (f) of this section, install, operate, calibrate and maintain, in accordance with the requirements in paragraphs (g)(1) through (7) of this section, a CPMS to measure and record the pressure in the flare gas header between the knock-out pot and water seal and to measure and record the water seal liquid level. If the required monitoring systems are not already in place, the owner or operator of a modified flare shall comply with the requirements of this paragraph by no later than November 11, 2015 or upon startup of the modified flare, whichever is later.

(1) Locate the pressure sensor(s) in a position that provides a representative measurement of the pressure and locate the liquid seal level monitor in a position that provides a representative measurement of the water column height.

(2) Minimize or eliminate pulsating pressure, vibration and internal and external corrosion.

(3) Use a pressure sensor and level monitor with a minimum tolerance of 1.27 centimeters of water.

(4) Using a manometer, check pressure sensor calibration quarterly.

(5) Conduct calibration checks any time the pressure sensor exceeds the manufacturer's specified maximum operating pressure range or install a new pressure sensor.

(6) In a cascaded flare system that employs multiple secondary flares, pressure and liquid level monitoring is required only on the first secondary flare in the system (*i.e.,* the secondary flare with the lowest pressure release set point).

(7) This alternative monitoring option may be elected only for flares with four or fewer pressure exceedances required to be reported under § 60.108a(d)(5) (''reportable pressure exceedances'') in any 365 consecutive calendar days. Following the fifth reportable pressure exceedance in a 365-day period, the owner or operator must comply with the sulfur and flow monitoring requirements of paragraphs (e) and (f) of this section as soon as practical, but no later than 180 days after the fifth reportable pressure exceedance in a 365-day period.

(h) *Alternative monitoring for flares located in the BAAQMD or SCAQMD.* An affected flare subject to this subpart located in the BAAQMD may elect to comply with the monitoring requirements in both BAAQMD Regulation 12, Rule 11 and BAAQMD Regulation 12, Rule 12 as an alternative to complying with the requirements of paragraphs (e) and (f) of this section. An affected flare subject to this subpart located in the SCAQMD may elect to comply with the monitoring requirements in SCAQMD Rule 1118 as an alternative to complying with the requirements of paragraphs (e) and (f) of this section.

(i) *Excess emissions.* For the purpose of reports required by § 60.7(c), periods of excess emissions for fuel gas combustion devices subject to the emissions limitations in § 60.102a(g) and flares subject to the concentration requirement in § 60.103a(h) are defined as specified in paragraphs (i)(1) through (5) of this section. Determine a rolling 3-hour or a rolling daily average as the arithmetic average of the applicable 1-hour averages (*e.g.,* a rolling 3-hour average is the arithmetic average of three contiguous 1-hour averages). Determine a rolling 30-day or a rolling 365-day average as the arithmetic average of the applicable daily averages (*e.g.,* a rolling 30-day average is the arithmetic average of 30 contiguous daily averages).

(1) *SO_2 or H_2S limits for fuel gas combustion devices.* (i) If the owner or operator of a fuel gas combustion device elects to comply with the SO_2 emission limits in § 60.102a(g)(1)(i), each rolling 3-hour period during which the average concentration of SO_2 as measured by the SO_2 continuous monitoring system required under paragraph (a)(1) of this section exceeds 20 ppmv, and each rolling 365-day period during which the average concentration of SO_2 as measured by the SO_2 continuous monitoring system required under paragraph (a)(1) of this section exceeds 8 ppmv.

(ii) If the owner or operator of a fuel gas combustion device elects to comply with the H_2S concentration limits in § 60.102a(g)(1)(ii), each rolling 3-hour period during which the average concentration of H_2S as measured by the

H_2S continuous monitoring system required under paragraph (a)(2) of this section exceeds 162 ppmv and each rolling 365-day period during which the average concentration as measured by the H_2S continuous monitoring system under paragraph (a)(2) of this section exceeds 60 ppmv.

(iii) If the owner or operator of a fuel gas combustion device becomes subject to the requirements of daily stain tube sampling in paragraph (b)(3)(iii) of this section, each day during which the daily concentration of H_2S exceeds 162 ppmv and each rolling 365-day period during which the average concentration of H_2S exceeds 60 ppmv.

(2) H_2S concentration limits for flares. (i) Each rolling 3-hour period during which the average concentration of H_2S as measured by the H_2S continuous monitoring system required under paragraph (a)(2) of this section exceeds 162 ppmv.

(ii) If the owner or operator of a flare becomes subject to the requirements of daily stain tube sampling in paragraph (b)(3)(iii) of this section, each day during which the daily concentration of H_2S exceeds 162 ppmv.

(3) *Rolling 30-day average NO_X limits for fuel gas combustion devices.* Each rolling 30-day period 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) For a natural draft process heater, 40 ppmv and, if monitored according to § 60.107a(d), 0.040 lb/MMBtu;

(ii) For a forced draft process heater, 60 ppmv and, if monitored according to § 60.107a(d), 0.060 lb/MMBtu; and

(iii) For a co-fired process heater electing to comply with the NO_X limit in § 60.102a(g)(2)(iii)(A) or (g)(2)(iv)(A), 150 ppmv.

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

(4) *Daily NO_X limits for fuel gas combustion devices.* Each day 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 daily average emissions limit calculated using Equation 3 in § 60.102a(g)(2)(iii)(B) or Equation 4 in § 60.102a(g)(2)(iv)(B).

(5) *Daily O_2 limits for fuel gas combustion devices.* Each day during which the concentration of O_2 as measured by the O_2 continuous monitoring system required under paragraph (c)(6) of this section exceeds the O_2 operating limit or operating curve determined during the most recent biennial performance test.

■ 18. Section 60.108a is amended by:
■ a. Revising paragraph (b);
■ b. Revising paragraph (c)(1);
■ c. Revising paragraph (c)(6) introductory text and paragraphs (c)(6)(ii) through (vi);
■ d. Adding paragraphs (c)(6)(vii), (viii), (ix), (x) and (xi);
■ e. Adding paragraph (c)(7); and
■ f. Revising paragraph (d)(5).

The revisions and additions read as follows:

§ 60.108a Recordkeeping and reporting requirements.

* * * * *

(b) Each owner or operator subject to an emissions limitation in § 60.102a shall notify the Administrator of the specific monitoring provisions of §§ 60.105a, 60.106a and 60.107a with which the owner or operator intends to comply. Each owner or operator of a co-fired process heater subject to an emissions limitation in § 60.102a(g)(2)(iii) or (iv) shall submit to the Administrator documentation showing that the process heater meets the definition of a co-fired process heater in § 60.101a. Notifications required by this paragraph shall be submitted with the notification of initial startup required by § 60.7(a)(3).

(c) * * *

(1) A copy of the flare management plan.

* * * * *

(6) Records of discharges greater than 500 lb SO_2 in any 24-hour period from any affected flare, discharges greater than 500 lb SO_2 in excess of the allowable limits from a fuel gas combustion device or sulfur recovery plant and discharges to an affected flare in excess of 500,000 scf above baseline in any 24-hour period as required by § 60.103a(c). If the monitoring alternative provided in § 60.107a(g) is selected, the owner or operator shall record any instance when the flare gas line pressure exceeds the water seal liquid depth, except for periods attributable to compressor staging that do not exceed the staging time specified in § 60.103a(a)(3)(vii)(C). 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, but are not allowed for flares, except for those complying with the alternative monitoring requirements in § 60.107a(g).

(iv) For each discharge greater than 500 lb SO_2 in any 24-hour period from a flare, the measured total sulfur concentration or both the measured H_2S 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 SO_2 in excess of the applicable short-term emissions limit in § 60.102a(g)(1) from a fuel gas combustion device, either the measured concentration of H_2S in the fuel gas or the measured concentration of SO_2 in the stream discharged to the atmosphere. Process knowledge can be used to make these estimates for fuel gas combustion devices, but cannot be used to make these estimates for flares, except as provided in § 60.107a(e)(4).

(vi) For each discharge greater than 500 lb SO_2 in excess of the allowable limits from a sulfur recovery plant, either the measured concentration of reduced sulfur or SO_2 discharged to the atmosphere.

(vii) For each discharge greater than 500 lb SO_2 in any 24-hour period from any affected flare or discharge greater than 500 lb SO_2 in excess of the allowable limits from a fuel gas combustion device or sulfur recovery plant, the cumulative quantity of H_2S and SO_2 released into the atmosphere. For releases controlled by flares, assume 99-percent conversion of reduced sulfur or total sulfur to SO_2. For fuel gas combustion devices, assume 99-percent conversion of H_2S to SO_2.

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

(ix) The root cause analysis and corrective action analysis conducted as required in § 60.103a(d), including an identification of the affected facility, the date and duration of the discharge, a statement noting whether the discharge resulted from the same root cause(s) identified in a previous analysis and either a description of the recommended corrective action(s) or an explanation of why corrective action is not necessary under § 60.103a(e).

(x) For any corrective action analysis for which corrective actions are required in § 60.103a(e), a description of the corrective action(s) completed within the first 45 days following the discharge

and, for action(s) not already completed, a schedule for implementation, including proposed commencement and completion dates.

(xi) For each discharge from any affected flare that is the result of a planned startup or shutdown of a refinery process unit or ancillary equipment connected to the affected flare, a statement that a root cause analysis and corrective action analysis are not necessary because the owner or operator followed the flare management plan.

(7) If the owner or operator elects to comply with § 60.107a(e)(2) for a flare, records of the H_2S and total sulfur analyses of each grab or integrated sample, the calculated daily total sulfur-to-H_2S ratios, the calculated 10-day average total sulfur-to-H_2S ratios and the 95-percent confidence intervals for each 10-day average total sulfur-to-H_2S ratio.

(d) * * *

(5) The information described in paragraph (c)(6) of this section for all discharges listed in paragraph (c)(6) of this section. For a flare complying with the monitoring alternative under § 60.107a(g), following the fifth discharge required to be recorded under paragraph (c)(6) of this section and reported under this paragraph, the owner or operator shall include notification that monitoring systems will be installed according to § 60.107a(e) and (f) within 180 days following the fifth discharge.

* * * * *

■ 19. 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 an application for an alternative means of emission limitation under § 60.103a(j) of this subpart.

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

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)	7.29	842
Ethane (C_2H_6)	12.96	1,475
Hydrogen (H_2)	1.61	269
Ethene (C_2H_4)	11.34	1,335
Propane (C_3H_8)	18.62	2,100
Propene (C_3H_6)	17.02	1,947
Butane (C_4H_{10})	24.30	2,717
Butene (C_4H_8)	22.69	2,558
Inerts	0.85	0

[a] MEV = molar exhaust volume, dry standard cubic feet per gram-mole (dscf/g-mol) at standard conditions of 68 °F and 1 atmosphere.

[b] MHC = molar heat content (higher heating value basis), Btu per gram-mole (Btu/g-mol).

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Part IV

Environmental Protection Agency

40 CFR Parts 60 and 63

National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines; New Source Performance Standards for Stationary Internal Combustion Engines; Final Rule

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 60 and 63

[EPA–HQ–OAR–2008–0708, FRL–9756–4]

RIN 2060–AQ58

National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines; New Source Performance Standards for Stationary Internal Combustion Engines

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: The EPA is finalizing amendments to the national emission standards for hazardous air pollutants for stationary reciprocating internal combustion engines. The final amendments include alternative testing options for certain large spark ignition (generally natural gas-fueled) stationary reciprocating internal combustion engines, management practices for a subset of existing spark ignition stationary reciprocating internal combustion engines in sparsely populated areas and alternative monitoring and compliance options for the same engines in populated areas. The EPA is establishing management practices for existing compression ignition engines on offshore vessels. The EPA is also finalizing limits on the hours that stationary emergency engines may be used for emergency demand response and establishing fuel and reporting requirements for certain emergency engines used for emergency demand response. The final amendments also correct minor technical or editing errors in the current regulations for stationary reciprocating internal combustion engines.

DATES: This final rule is effective on April 1, 2013. The incorporation by reference of certain publications listed in this final rule is approved by the Director of the Federal Register as of April 1, 2013.

ADDRESSES: The EPA has established a docket for this action under Docket ID No. EPA–HQ–OAR–2008–0708. The EPA also relies on materials in Docket ID Nos. EPA–HQ–OAR–2002–0059, EPA–HQ–OAR–2005–0029, and EPA–HQ–OAR–2005–0030 and incorporates those dockets into the record for this final rule. All documents in the docket are listed on the *www.regulations.gov* Web site. Although listed in the index, some information is not publicly available, e.g., Confidential Business Information or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the Internet and will be publicly available only in hard copy form. Publicly available docket materials are available either electronically through *www.regulations.gov* or in hard copy at the Air and Radiation Docket, EPA/DC, EPA West, 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 Air Docket is (202) 566–1742.

FOR FURTHER INFORMATION CONTACT: Ms. Melanie King, Energy Strategies Group, Sector Policies and Programs Division (D243–01), Environmental Protection Agency, Research Triangle Park, North Carolina 27711; telephone number (919) 541–2469; facsimile number (919) 541–5450; email address *king.melanie@epa.gov.*

SUPPLEMENTARY INFORMATION: *Background Information Document.* On June 7, 2012 (77 FR 33812), the EPA proposed amendments to the national emission standards for hazardous air pollutants (NESHAP) for stationary reciprocating internal combustion engines (RICE) and the new source performance standards (NSPS) for stationary engines. A summary of the public comments on the proposal and the EPA's responses to the comments, as well as the Regulatory Impact Analysis Report, are available in Docket ID No. EPA–HQ–OAR–2008–0708.

SUPPLEMENTARY INFORMATION: *Organization of This Document.* The following outline is provided to aid in locating information in the preamble.

I. General Information
- A. Executive Summary
- B. Does this action apply to me?
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II. Summary of Final Amendments
- A. Total Hydrocarbon Compliance Demonstration Option
- B. Emergency Demand Response and Reliability
- C. Peak Shaving
- D. Non-Emergency Stationary SI RICE Greater Than 500 HP Located at Area Sources
- E. Stationary CI RICE Certified to Tier Standards
- F. Definition for Remote Areas of Alaska
- G. Requirements for Offshore Vessels
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III. Summary of Significant Changes Since Proposal
- A. Emergency Demand Response and Reliability
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IV. Summary of Environmental, Energy and Economic Impacts
- A. What are the air quality impacts?
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- A. Executive Order 12866: Regulatory Planning and Review and Executive Order 13563: Improving Regulation and Regulatory Review
- B. Paperwork Reduction Act
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- F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments
- G. Executive Order 13045: Protection of Children From Environmental Health Risks and Safety Risks
- H. Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use
- I. National Technology Transfer and Advancement Act
- J. Executive Order 12898: Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations
- K. Congressional Review Act

I. General Information

A. Executive Summary

1. Purpose of the Regulatory Action

The purpose of this action is to finalize amendments to the NESHAP for stationary RICE under section 112 of the Clean Air Act (CAA). This final rule was developed to address certain issues that were raised by various stakeholders through lawsuits, several petitions for reconsideration of the 2010 RICE NESHAP amendments and other communications. This final rule also provides clarifications and corrects minor technical or editing errors in the current RICE NESHAP and revises the NSPS for stationary engines, 40 CFR part 60, subparts IIII and JJJJ, for consistency with the RICE NESHAP.

This action is conducted under the authority of section 112 of the CAA, ''Hazardous Air Pollutants'' (HAP), which requires the EPA to establish NESHAP for the control of HAP from both new and existing sources in regulated source categories.

2. Summary of the Major Provisions of the Regulatory Action

After promulgation of the 2010 RICE NESHAP amendments, the EPA received several petitions for reconsideration, legal challenges, other communications raising issues related to practical implementation and certain factual information that had not been brought to the EPA's attention during the rulemaking. The EPA has considered this information and comments submitted in response to the proposed amendments, and believes that amendments to the rule to address certain issues are appropriate. Therefore, the EPA is finalizing amendments to 40 CFR part 63, subpart ZZZZ, NESHAP for stationary RICE. The current regulation applies to owners and operators of existing and new stationary RICE at major and area sources of HAP emissions. The applicability of the rule remains the same and is not changed by this final rule. The EPA is also finalizing amendments to the NSPS for stationary engines to conform with certain amendments finalized for the RICE NESHAP. The key amendments to the regulations are summarized in the following paragraphs.

The EPA is adding an alternative compliance demonstration option for stationary 4-stroke rich burn (4SRB) spark ignition (SI) engines subject to a 76 percent or more formaldehyde reduction requirement. Owners and operators of 4SRB engines will be permitted to demonstrate compliance with the 76 percent formaldehyde reduction emission standard by testing emissions of total hydrocarbons (THC) and showing that the engine is achieving at least a 30 percent reduction of THC emissions. The alternative compliance option provides a less expensive and less complex, but equally effective, method for demonstrating compliance than testing for formaldehyde.

Certain stationary RICE are maintained in order to be able to respond to emergency power needs. This action finalizes limitations on the operation of emergency engines for emergency demand response programs. The final rule limits operation of stationary emergency RICE as part of an emergency demand response program to within the 100 hours per year that were already permitted for maintenance and testing of the engines. The limitation of 100 hours per year ensures that a sufficient number of hours are available for engines to meet regional transmission organization and independent system operator tariffs and other requirements for participating in various emergency demand response programs and will assist in stabilizing the grid during periods of instability, preventing electrical blackouts and supporting local electric system reliability. The final rule also limits operation of certain emergency engines used to avert potential voltage collapse or line overloads that could lead to the interruption of power supply in a local area or region to 50 hours per year; this operation counts as part of the 100 hours of year permitted for maintenance and testing of the engine. This rule also establishes fuel and reporting requirements for emergency engines larger than 100 horsepower (HP) used for this purpose or used (or contractually obligated to be available) for more than 15 hours of emergency demand response per calendar year.

The EPA is finalizing management practices for owners and operators of existing stationary 4-stroke SI engines above 500 HP that are area sources of HAP emissions and where the engines are remote from human activity. A remote area is defined as either a Department of Transportation (DOT) Class 1 pipeline location,[1] or, if the engine is not on a pipeline, if within a 0.25 mile radius of the facility there are 5 or fewer buildings intended for human occupancy. The EPA determined that a 0.25 mile radius was appropriate because it is similar to the area used for the DOT Class 1 pipeline location. This final rule establishes management practices for these sources rather than numeric emission limits and associated testing and monitoring. This provision and the division of remote and non-remote engines into two separate subcategories addresses reasonable concerns with accessibility, infrastructure and staffing that stem from the remoteness of the engines and higher costs that would be associated with compliance with the existing requirements. Existing stationary 4-stroke SI engines above 500 HP at area sources that are in populated areas (defined as not in DOT pipeline Class 1 areas, or if not on a pipeline, if within a 0.25 mile radius of the engine there are more than 5 buildings intended for human occupancy) are subject to an equipment standard that requires the installation of HAP-reducing aftertreatment. The EPA has the discretion to set an equipment standard as generally available control technology (GACT) for engines located at area sources of HAP. Sources are required to test their engines to demonstrate compliance initially, perform catalyst activity check-ups and either monitor the catalyst inlet temperature continuously or employ high temperature shutdown devices to protect the catalyst.

To address how certain existing compression ignition (CI) engines are currently regulated, the EPA is specifying that any existing CI engine above 300 HP at an area source of HAP emissions that was certified to meet the Tier 3 engine standards[2] and was installed before June 12, 2006, is in compliance with the NESHAP. This provision creates regulatory consistency between the same engines installed before and after June 12, 2006. Engines at area sources of HAP for which construction commenced before June 12, 2006, are considered existing engines under the NESHAP.

The EPA is finalizing amendments to the requirements for existing stationary Tier 1 and Tier 2 certified CI engines located at area sources that are subject to state and locally enforceable requirements requiring replacement of the engine by June 1, 2018. This addresses a specific concern regarding the interaction of the NESHAP with certain rules for agricultural engines in the San Joaquin Valley in California. The EPA is allowing these engines to meet management practices under the RICE NESHAP from the May 3, 2013, compliance date until January 1, 2015, or 12 years after installation date, but not later than June 1, 2018. This provision addresses concerns about requiring owners and operators to install controls on their engines in order to meet the RICE NESHAP, and then having to replace their engines shortly thereafter due to state and local rules specifying the replacement of engines. Owners and operators will have additional time to replace their engines without having to install controls, but are required to use management practices during that period.

Another change the EPA is making is to broaden the definition of remote area sources in Alaska in the RICE NESHAP. Previously, remote areas were considered those that are not on the Federal Aid Highway System (FAHS). This change permits existing stationary CI engines at other remote area sources in Alaska to meet management practices rather than numerical emission standards likely to require

[1] A Class 1 location is defined as an offshore area or any class location unit that has 10 or fewer buildings intended for human occupancy and no buildings with four or more stories within 220 yards (200 meters) on either side of the centerline of any continuous 1-mile (1.6 kilometers) length of pipeline.

[2] See 40 CFR part 89—Control of Emissions From New and In-Use Nonroad Compression-Ignition Engines.

aftertreatment. These remote areas have the same challenges as areas not on the FAHS, and complying with the current rule would similarly be prohibitively costly and potentially infeasible. In addition to area sources located in areas of Alaska that are not accessible by the FAHS being defined as remote and subject to management practices, any stationary RICE in Alaska meeting all of the following conditions are subject to management practices:

(1) The only connection to the FAHS is through the Alaska Marine Highway System, or the stationary RICE operation is within an isolated grid in Alaska that is not connected to the statewide electrical grid referred to as the Alaska Railbelt Grid, and

(2) At least 10 percent of the power generated by the stationary RICE on an annual basis is used for residential purposes, and

(3) The generating capacity of the area source is less than 12 megawatts (MW), or the stationary RICE is used exclusively for backup power for renewable energy.

The last significant change the EPA is finalizing is to require compliance with management practices rather than numeric emission limits in the RICE NESHAP for existing CI RICE on offshore drilling vessels on the Outer Continental Shelf (OCS) that become subject to the RICE NESHAP as a result of the operation of the OCS regulations (40 CFR part 55). The final amendments specify that owners and operators of existing non-emergency CI RICE with a site rating greater than 300 HP on offshore drilling vessels on the OCS are required to change the oil every 1,000 hours of operation or annually, whichever occurs first; inspect and clean air filters every 750 hours of operation or annually and replace as necessary; inspect fuel filters and belts, if installed, every 750 hours of operation or annually and replace as necessary; and inspect all flexible hoses every 1,000 hours of operation or annually and replace as necessary. Owners and operators can elect to use an oil analysis program to extend the oil change requirement.

3. Costs and Benefits

These final amendments will reduce the capital and annual costs of the original 2010 amendments by $287 million and $139 million, respectively. The EPA estimates that with these final amendments, the capital cost of compliance with the 2010 amendments to the RICE NESHAP in 2013 is $840 million and the annual cost is $490 million ($2010). These costs are identical to the costs estimated for the amendments to the RICE NESHAP proposed on June 7, 2012, since the changes from the proposal do not affect the costs of the rule in the year 2013. The capital and annual costs of the original 2010 final rule and the 2010 final rule with these final amendments incorporated into the rule are shown in Table 1.

TABLE 1—SUMMARY OF COST IMPACTS FOR EXISTING STATIONARY RICE

Engine	2010 Final rule		2010 Final rule with these final amendments
	Total Annual Cost		
SI	$253 million ($2009)	$251 million ($2010)	$115 million ($2010).
CI	$373 million ($2008)	$375 million ($2010)	$373 million ($2010).
	Total Capital Cost		
SI	$383 million ($2009)	$380 million ($2010)	$103 million ($2010).
CI	$744 million ($2008)	$748 million ($2010)	$740 million ($2010).

These final amendments would also result in decreases to the emissions reductions estimated in 2013 from the original 2010 RICE NESHAP amendments. The reductions that were estimated for the original 2010 RICE NESHAP amendments were 7,000 tpy of HAP, 124,000 tpy of CO, 2,800 tpy of PM, 96,000 tpy of NO_X and 58,000 tpy of VOC. The estimated reductions in 2013 from the 2010 RICE NESHAP rulemaking with these final amendments are 2,800 tons per year (tpy) of HAP, 36,000 tpy of carbon monoxide (CO), 2,800 tpy of particulate matter (PM), 9,600 tpy of nitrogen oxide (NO_X), and 36,000 tpy of volatile organic compounds (VOC). The difference in the emission reductions is primarily due to the changes to the requirements for existing 4-stroke stationary SI RICE at area sources of HAP that are in remote areas. These emission reduction estimates are identical to those estimated for the June 7, 2012, proposed amendments to the RICE NESHAP. The emission reductions of the original 2010 final rule and the 2010 final rule with these final amendments incorporated into the rule are shown in Table 2.

TABLE 2—SUMMARY OF REDUCTIONS FOR EXISTING STATIONARY RICE

Pollutant	Emission reductions (tpy) in the year 2013			
	2010 Final rule		2010 Final rule with these final amendments	
	CI	SI	CI	SI
HAP	1,014	6,008	1,005	1,778
CO	14,342	109,321	14,238	22,211
PM	2,844	N/A	2,818	N/A
NO_X	N/A	96,479	N/A	9,648
VOC	27,395	30,907	27,142	9,147

The EPA estimates the monetized co-benefits in 2013 of the original 2010 RICE NESHAP amendments with these final amendments incorporated to be $830 million to $2,100 million (2010 dollars) at a 3-percent discount rate and $740 million to $1,800 million (2010 dollars) at a 7-percent discount rate. The benefits that were estimated for the original 2010 RICE NESHAP amendments were $1,500 million to $3,600 million (2010 dollars) at a 3-percent discount rate and $1,300 million to $3,200 million (2010 dollars) at a 7-percent discount rate. A summary of the monetized co-benefits estimates for CI and SI engines at discount rates of 3 percent and 7 percent for the original 2010 final rule and the 2010 final rule with these final amendments incorporated into the rule is in Table 3 of this preamble.

TABLE 3—SUMMARY OF THE MONETIZED $PM_{2.5}$ CO-BENEFITS FINAL AMENDMENTS TO THE NESHAP FOR STATIONARY CI AND SI ENGINES

[millions of 2010 dollars] [a, b]

Pollutant	Emission reductions (tons per year)	Total monetized co-benefits (3 percent discount)	Total monetized co-benefits (7 percent discount)
Original 2010 Final Rules [c]			
Stationary CI Engines: Total Benefits	2,844 $PM_{2.5}$ 27,395 VOC	$950 to $2,300	$860 to $2,100.
Stationary SI Engines: Total Benefits	96,479 NO_X 30,907 VOC	$510 to $1,300	$470 to $1,100.
2010 Final Rules With These Final Amendments			
Stationary CI Engines: Directly emitted $PM_{2.5}$	2,818	$770 to $1,900	$690 to $1,700.
Stationary SI Engines: NO_X	9,648	$62 to $150	$55 to $140.

[a] All estimates are for the analysis year (2013) and are rounded to two significant figures so numbers may not sum across rows. The total monetized co-benefits reflect the human health benefits associated with reducing exposure to $PM_{2.5}$ through reductions of $PM_{2.5}$ precursors, such as NO_X and directly emitted $PM_{2.5}$. It is important to note that the monetized co-benefits do not include reduced health effects from exposure to HAP, direct exposure to NO_2, exposure to ozone, ecosystem effects or visibility impairment.

[b] PM co-benefits are shown as a range from Pope, *et al.* (2002) to Laden, *et al.* (2006). These models assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because the scientific evidence is not yet sufficient to allow differentiation of effects estimates by particle type.

[c] The benefits analysis for the 2010 final rules applied out-dated benefit-per-ton estimates compared to the updated estimates described in this preamble and reflected monetized co-benefits for VOC emissions, which limits direct comparability with the monetized co-benefits estimated for this final rule. In addition, these estimates have been updated from their original currency years to 2010$, so the rounded estimates for the 2010 final rules may not match the original RIAs.

We have not re-estimated the benefits for the final rule compared to the proposal because the emission reductions estimated for the final rule are the same as those estimated for the proposed amendments. Since the June 7, 2012, reconsideration proposal, the EPA has made several updates to the approach we use to estimate mortality and morbidity benefits in the PM NAAQS Regulatory Impact Analysis (RIA),[3, 4] including updated epidemiology studies, health endpoints, and population data. Although the EPA has not re-estimated the benefits for this rule to apply this new approach, these updates generally offset each other, and we anticipate that the rounded benefits estimated for this rule are unlikely to be different than those provided above.

More detail regarding the air quality and cost impacts and the benefits from this action can be found in section IV of this preamble.

B. Does this action apply to me?

Regulated Entities. Categories and entities potentially regulated by this action include:

Category	NAICS [1]	Examples of regulated entities
Any industry using a stationary internal combustion engine as defined in the final amendments.	2211	Electric power generation, transmission, or distribution.
	622110	Medical and surgical hospitals.
	48621	Natural gas transmission.
	211111	Crude petroleum and natural gas production.
	211112	Natural gas liquids producers.
	92811	National security.

[1] North American Industry Classification System.

[3] U.S. Environmental Protection Agency (U.S. EPA). 2012a. *Regulatory Impact Analysis for the Proposed Revisions to the National Ambient Air Quality Standards for Particulate Matter.* EPA–452/R–12–003. Office of Air Quality Planning and Standards, Health and Environmental Impacts Division. June. Available at *http://www.epa.gov/ttnecas1/regdata/RIAs/PMRIACombinedFile_Bookmarked.pdf.*

[4] U.S. Environmental Protection Agency (U.S. EPA). 2012b. *Regulatory Impact Analysis for the Final Revisions to the National Ambient Air Quality Standards for Particulate Matter.* EPA–452/R–12–003. Office of Air Quality Planning and Standards, Health and Environmental Impacts Division. December. Available at *http://www.epa.gov/pm/2012/finalria.pdf.*

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 an engine is regulated by this action, owners and operators should examine the applicability criteria of this final rule. For any questions regarding the applicability of this action to a particular entity, consult the person listed in the preceding **FOR FURTHER INFORMATION CONTACT** section.

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

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

D. Judicial Review

Under section 307(b)(1) of the CAA, judicial review of this final rule is available only by filing a petition for review in the U.S. Court of Appeals for the District of Columbia Circuit by April 1, 2013. Under section 307(d)(7)(B) of the CAA, only an objection to this final rule that was raised with reasonable specificity during the period for public comment can be raised during judicial review. Moreover, under section 307(b)(2) of the CAA, the requirements established by this final rule may not be challenged separately in any civil or criminal proceedings brought by EPA to enforce these requirements. Section 307(d)(7)(B) of the CAA further provides that "[o]nly an objection to a rule or procedure which was raised with reasonable specificity during the period for public comment (including any public hearing) may be raised during judicial review." This section also provides a mechanism for us to convene a proceeding for reconsideration, "[i]f the person raising an objection can demonstrate to the EPA that it was impracticable to raise such objection within [the period for public comment] or if the grounds for such objection arose after the period for public comment (but within the time specified for judicial review) and if such objection is of central relevance to the outcome of the rule." Any person seeking to make such a demonstration to us should submit a Petition for Reconsideration to the Office of the Administrator, U.S. EPA, Room 3000, Ariel Rios Building, 1200 Pennsylvania Ave. NW., Washington, DC 20460, with a copy to both the person(s) listed in the preceding **FOR FURTHER INFORMATION CONTACT** section, and the Associate General Counsel for the Air and Radiation Law Office, Office of General Counsel (Mail Code 2344A), U.S. EPA, 1200 Pennsylvania Ave. NW., Washington, DC 20460.

II. Summary of Final Amendments

This action finalizes amendments to the NESHAP for RICE in 40 CFR part 63, subpart ZZZZ. This action also finalizes amendments to the NSPS for stationary engines in 40 CFR part 60, subparts IIII and JJJJ. The NESHAP for stationary RICE to regulate emissions of HAP was developed in several stages. The EPA initially addressed stationary RICE greater than 500 HP located at major sources of HAP emissions in 2004 (69 FR 33473). The EPA addressed new stationary RICE less than or equal to 500 HP located at major sources and new stationary RICE located at area sources in 2008 (73 FR 3568). Most recently, requirements for existing stationary RICE less than or equal to 500 HP located at major sources and existing stationary RICE located at area sources were finalized in 2010 (75 FR 9648 and 75 FR 51570).

The EPA is finalizing these amendments to address a number of issues that have been raised by different stakeholders through lawsuits, several petitions for reconsideration of the 2010 RICE NESHAP amendments, and other communications. The EPA is also finalizing revisions to 40 CFR part 60, subparts IIII and JJJJ for consistency with the RICE NESHAP and to make minor corrections and clarifications. The amendments that the EPA is finalizing in this action are discussed in this section. The changes from the proposal to this final rule are discussed in section III.

A. Total Hydrocarbon Compliance Demonstration Option

The EPA is adding an alternative method of demonstrating compliance with the NESHAP for existing and new stationary 4SRB non-emergency engines greater than 500 HP that are located at major sources of HAP emissions. Under these final amendments, the emission standard remains the same, that is, existing and new stationary 4SRB engines greater than 500 HP and located at major sources are still required to reduce formaldehyde emissions by 76 percent or more or limit the concentration of formaldehyde in the stationary RICE exhaust to 350 parts per billion by volume, dry basis or less at 15 percent oxygen (O_2). This final rule adds an alternative compliance demonstration option to the existing method of demonstrating compliance with the formaldehyde percent reduction standard. The current method is to test engines for formaldehyde. The alternative for owners and operators of 4SRB engines meeting a 76 percent or more formaldehyde reduction is to test their engines for THC showing that the engine is achieving at least a 30 percent reduction of THC emissions. Including this optional THC compliance demonstration option reduces the cost of compliance significantly while continuing to achieve the same level of HAP emission reduction because the emission standards would remain the same. As discussed in the June 7, 2012, proposal, data provided to EPA indicate that a strong relationship exists between percentage reductions of THC and percentage reductions of formaldehyde (the surrogate for HAP emissions in the NESHAP) on rich burn engines using non-selective catalytic reduction (NSCR). Data analyzed by the EPA indicate that if the NSCR is reducing THC by at least 30 percent from 4SRB engines, formaldehyde emissions are guaranteed to be reduced by at least 76 percent, which is the percentage reduction required for the relevant engines. Indeed, the percentage reduction of formaldehyde is invariably well above the 76 percent level, and is usually above 90 percent. Therefore, the EPA concluded that for SI 4SRB engines using NSCR and meeting the NESHAP by showing a percentage reduction of HAP, it would be appropriate to allow sources to demonstrate compliance with the NESHAP by showing a THC reduction of at least 30 percent. Owners and operators of existing stationary 4SRB engines less than or equal to 500 HP that are required to limit the concentration of formaldehyde in the stationary RICE exhaust to 10.3 parts per million by volume, dry basis (ppmvd) or less at 15 percent O_2 do not have the option to demonstrate compliance using THC and must continue to demonstrate compliance by testing for formaldehyde following the methods and procedures specified in the rule because the EPA could not verify a clear relationship between concentrations of THC and concentrations of formaldehyde in the exhaust from these SI 4SRB engines.

Owners and operators opting to use the THC compliance demonstration method must demonstrate compliance by showing that the average reduction of THC is equal to or greater than 30 percent. Owners and operators of 4SRB stationary RICE complying with the

requirement to reduce formaldehyde emissions and demonstrating compliance by using the THC compliance demonstration option must conduct performance testing using Method 25A of 40 CFR part 60, appendix A—Determination of Total Gaseous Organic Concentration Using a Flame Ionization Analyzer. Measurements of THC at the inlet and the outlet of the NSCR must be on a dry basis and corrected to 15 percent O_2 or equivalent carbon dioxide content. To correct to 15 percent O_2, dry basis, owners and operators must measure oxygen using Method 3, 3A or 3B of 40 CFR part 60, appendix A, or ASTM Method D6522–00 (2005) and measure moisture using Method 4 of 40 CFR part 60, appendix A, or Test Method 320 of 40 CFR part 63, appendix A, or ASTM D6348–03. Because owners and operators are complying with a percent reduction requirement, the method used must be suitable for the entire range of emissions since pre and post-catalyst emissions must be measured. Method 25A is capable of measuring emissions down to 5 ppmv and is, therefore, an appropriate method for measuring THC emissions for compliance demonstration purposes. The EPA is allowing sources the option to meet a minimum THC percent reduction of 30 percent by using Method 25A of 40 CFR part 60, appendix A to demonstrate compliance with the formaldehyde percent reduction in 40 CFR part 63, subpart ZZZZ.

B. Emergency Demand Response and Reliability

The EPA is finalizing certain revisions to the proposal regarding use of existing engines for emergency demand response and system reliability. Following is a summary of the prior requirements for these engines, including those in the 2010 regulation, a discussion of the information and input the EPA received in response to the proposal, and a description of the provisions being finalized in this action.

Existing emergency engines less than or equal to 500 HP located at major sources of HAP and existing emergency engines located at area sources of HAP were not regulated under the RICE NESHAP rulemakings finalized in 2004 and 2008. They could operate uncontrolled for an unlimited amount of time. The 2010 RICE NESHAP rulemaking for the first time established requirements for these existing emergency engines, requiring affected engines to comply by May 3, 2013, for stationary CI RICE and October 19, 2013, for stationary SI RICE. Under the RICE NESHAP requirements originally finalized in 2010, these existing emergency stationary engines must limit operation to situations like blackouts and floods and to a maximum of 100 hours per year for other specified operations beginning with the applicable compliance date in 2013 for the engine. The limitation of 100 hours per year included maintenance checks and readiness testing of the engine, as well as a limit of 15 hours per year for use as part of a demand response program if the regional transmission organization or equivalent balancing authority and transmission operator has determined there are emergency conditions that could lead to a potential electrical blackout, such as unusually low frequency, equipment overload, capacity or energy deficiency, or unacceptable voltage level. Under the 2010 regulation, existing emergency engines were required to meet management practice standards based on proper operation and maintenance of the engine; meeting these standards would not require installation of aftertreatment to control emissions.

Soon after the 2010 rule was final, the EPA received petitions for reconsideration of the 15-hour limitation for emergency demand response that was finalized in the 2010 rule. According to one petition, the 15-hour limit, while usually adequate to cover the limited hours in which these engines are expected to be called upon, would not be sufficient to allow these emergency engines to participate in emergency demand response programs since some regional transmission organizations and independent system operators require engines be available for more than 15 hours in order to meet emergency demand response situations. For example, PJM's Emergency Load Response Program requires that emergency engines guarantee that they will be available for 60 hours per year. By contrast, another petition asked EPA to eliminate the emergency demand response provision because of the adverse effects that the petitioner believes would result from increased emissions from these engines. The EPA received other comments that addressed the types of situations in which engines are called upon for emergency demand response and system reliability.

The EPA believes that the emergency demand response programs that exist across the country are important programs that protect the reliability and stability of the national electric service grid. The use of stationary emergency engines as part of emergency demand response programs can help prevent grid failure or blackouts, by allowing these engines to be used for limited hours in specific circumstances of grid instability prior to the occurrence of blackouts. A standard that requires owners and operators of stationary emergency engines that participate in emergency demand response programs to apply aftertreatment could make it economically infeasible for these engines to participate in these programs, impairing the ability of regional transmission organizations and independent system operators to use these relatively small, quick-starting and reliable sources of energy to protect the reliability of their systems in times of critical need. Information provided by commenters on the proposal indicates that these emergency demand response events are rarely called.[5]

The limited circumstances specified in the final rule for operation of stationary emergency engines for emergency demand response purposes include periods during which the Reliability Coordinator, or other authorized entity as determined by the Reliability Coordinator, has declared an Energy Emergency Alert (EEA) Level 2 as defined in the North American Electric Reliability Corporation (NERC) Reliability Standard EOP–002–3, Capacity and Energy Emergency, and during periods where there is a deviation of voltage or frequency of 5 percent or more below standard voltage or frequency. During EEA Level 2 alerts there is insufficient energy supply and a true potential for electrical blackouts. System operators must call on all available resources during EEA Level 2 alerts in order to stabilize the grid to prevent failure. Therefore, this situation is a good indicator of severe instability on the system, which the EPA believes is appropriately considered an emergency situation. Consistent normal voltage provided by the utility is often called power quality and is an important factor in local electric system reliability. Reliability of the system requires electricity being provided at a normal expected voltage. The American National Standards Institute standard C84.1–1989 defines the maximum allowable voltage sag at below 5 percent. On the local distribution level local voltage levels are therefore important and a 5 percent or more change in the normal voltage or frequency is substantial and an indication that additional resources are needed to ensure local distribution system reliability.

In addition to the circumstances described above, the EPA also received comments on other situations where the

[5] See document number EPA–HQ–OAR–2008–0708–1142 in the rulemaking docket.

local transmission and distribution system operator has determined that there are conditions that could lead to a blackout for the local area where the ready availability of emergency engines is critical to system reliability. These include situations where:

- The engine is dispatched by the local balancing authority or local transmission and distribution system operator.
- The dispatch is intended to mitigate local transmission and/or distribution limitations so as to avert potential voltage collapse or line overloads that could lead to the interruption of power supply in a local area or region.
- The dispatch follows reliability, emergency operation or similar protocols that follow specific NERC, regional, state, public utility commission or local standards or guidelines.

The EPA believes the operation of emergency engines in these situations should be addressed in the final rule as well.

Therefore, based on the EPA's review of the petitions and comments that the EPA has received with respect to emergency demand response and system reliability, the EPA has concluded that it is appropriate to revise the provisions for stationary engines used in these limited circumstances. The provisions the EPA is amending are in §§ 63.6640(f) and 63.6675 of 40 CFR part 63, subpart ZZZZ. The final amendments to those sections specify that owners and operators of stationary emergency RICE can operate their engines as part of an emergency demand response program within the 100 hours already provided for operation for maintenance and testing. Owners and operators of stationary emergency engines can operate for up to 100 hours per year for emergency demand response and system reliability during periods in which the Reliability Coordinator, or other authorized entity as determined by the Reliability Coordinator, has declared an EEA Level 2 as defined in the NERC Reliability Standard EOP–002–3, Capacity and Energy Emergency, and during periods where there is a deviation of voltage or frequency of 5 percent or greater below standard voltage or frequency. In addition, existing emergency stationary RICE at area sources of HAP can operate for up to 50 hours per year if all of the following conditions are met:

- The engine is dispatched by the local balancing authority or local transmission and distribution system operator.
- The dispatch is intended to mitigate local transmission and/or distribution limitations so as to avert potential voltage collapse or line overloads that could lead to the interruption of power supply in a local area or region.
- The dispatch follows reliability, emergency operation or similar protocols that follow specific NERC, regional, state, public utility commission or local standards or guidelines.
- The owner or operator has a pre-existing plan that contemplates the engine's operation under the circumstances described above; and
- The owner or operator identifies and records the specific NERC, regional, state, public utility commission or local standards or guidelines that are being followed for dispatching the engine. The local balancing authority or local transmission and distribution system operator may keep these records on behalf of the engine owner or operator.

For all engines operating to satisfy emergency demand response or system reliability under the circumstances described above, the hours spent for emergency demand response operation and local system reliability are added to the hours spent for maintenance and testing purposes and are counted towards the limit of 100 hours per year. If the total time spent for maintenance and testing, emergency demand response, and system reliability operation exceeds 100 hours per year, the engine will not be considered an emergency engine under this subpart and will need to meet all requirements for non-emergency engines.

As noted above, the EPA received comments expressing concerns about the emissions from emergency engines, noting that the engines are likely to be dispatched on days when energy demand is high, which often coincides with days when air quality is poor. While the EPA is sensitive to these concerns, the availability of these engines for a more tailored response to emergencies may be preferable in terms of air quality impacts than relying on other generation, including coal-fired spinning reserve generation. After consideration of the concerns raised in the comments, the EPA is finalizing provisions that require stationary emergency CI RICE with a site rating of more than 100 brake HP and a displacement of less than 30 liters per cylinder that operate or are contractually obligated to be available for more than 15 hours per year (up to a maximum of 100 hours per year) for emergency demand response, or that operate for local system reliability, to use diesel fuel meeting the specifications of 40 CFR 80.510(b) beginning January 1, 2015, except that any existing diesel fuel purchased (or otherwise obtained) prior to January 1, 2015, may be used until depleted. The specifications of 40 CFR 80.510(b) require that diesel fuel have a maximum sulfur content of 15 ppm and either a minimum cetane index of 40 or a maximum aromatic content of 35 volume percent; this fuel is referred to as "ultra low sulfur diesel fuel" (ULSD). This emission reduction requirement was not part of the original 2010 rulemaking. Although the EPA does not have information specifying the percentage of existing stationary emergency CI engines currently using residual fuel oil or non-ULSD distillate fuel, the most recent U.S. Energy Information Administration data available for sales of distillate and residual fuel oil to end users [6] show that significant amounts of non-ULSD are still being purchased by end users that typically operate stationary combustion sources, including stationary emergency CI engines. For example, in the category of Commercial End Use, sales data for the year 2011 show that only 56 percent of the total distillate and residual fuel oil sold was ULSD. The data provided for Electric Power End Use show that 57 percent of total fuel sold was residual fuel oil. For Industrial End Use, the percentage of total fuel that was residual fuel oil was 26 percent. The EPA believes that requiring cleaner fuel for these stationary emergency CI engines will significantly limit or reduce the emissions of regulated air pollutants emitted from these engines, further protecting public health and the environment. Information provided to EPA by commenters [7] showed that the use of ULSD will significantly reduce emissions of air toxics, including metallic HAP (e.g., nickel, zinc, lead) and benzene.

In addition to the fuel requirement, owners and operators of stationary emergency CI RICE larger than 100 HP that operate or are contractually obligated to be available for more than 15 hours per year (up to a maximum of 100 hours per year) for emergency demand response must report the dates and times the engines operate for emergency demand response annually to the EPA, beginning with operation during the 2015 calendar year. Owners and operators of these engines are also required to report the dates, times and situations that the engines operate to mitigate local transmission and/or

[6] U.S. Energy Information Administration. Distillate Fuel Oil and Kerosene Sales by End Use. Available at *http://www.eia.gov/dnav/pet/pet_cons_821use_dcu_nus_a.htm*.

[7] See document number EPA–HQ–OAR–2008–0708–1459 in the rulemaking docket.

distribution limitations annually to the EPA, beginning with operation during the 2015 calendar year. This information is necessary to determine whether these engines are operating in compliance with the regulations and will assist the EPA in assessing the impacts of the emissions from these engines.

The EPA is adding these requirements beginning in January, 2015, rather than upon initial implementation of the NESHAP for existing engines in May or October of 2013, to provide sources with appropriate lead time to institute these new requirements and make any physical adjustments to engines and other facilities like tanks or other containment structures, as well as any needed adjustments to contracts and other business activities, that may be necessitated by these new requirements.

The EPA is also amending the NSPS for stationary CI and SI engines in 40 CFR part 60, subparts IIII and JJJJ, respectively, to provide the same limitation for stationary emergency engines for emergency demand response and system reliability operation as for engines subject to the RICE NESHAP. The NSPS regulations currently do not include such a provision for emergency demand response or system reliability operation; the issue was not raised during the original promulgation of the NSPS. The EPA is adding an emergency demand response and system reliability provision under the NSPS regulations in these final amendments. The EPA is revising the existing language in §§ 60.4211(f) and 60.4219 of 40 CFR part 60, subpart IIII, and §§ 60.4243(d) and 60.4248 of 40 CFR part 60, subpart JJJJ, to specify that emergency engines must limit operation for engine maintenance and testing and emergency demand response to a maximum of 100 hours per year; 50 of the 100 hours may be used to operate to mitigate local reliability issues, as discussed previously for the RICE NESHAP.

The EPA is also finalizing amendments to the NSPS regulations that require owners and operators of stationary emergency engines larger than 100 HP that operate or are contractually obligated to be available for more than 15 hours per year (up to a maximum of 100 hours per year) for emergency demand response to report the dates and times the engines operated for emergency demand response annually to the EPA, beginning with operation during the 2015 calendar year. Owners and operators of these engines are also required to report the dates, times and situations that the engines operate to mitigate local transmission and/or distribution limitations annually to the EPA, beginning with operation during the 2015 calendar year. The EPA anticipates that in most cases, the entity that dispatches the engines to operate, such as the curtailment service provider or utility, will report the information to the EPA on behalf of the facility that owns the engine. Thus, the burden of the reporting requirement will likely be on the entities that dispatch the engines. The EPA's burden estimate (see section V.B Paperwork Reduction Act) assumes the dispatching entity will report the date and hours dispatched without contacting individual engine operators. Emergency engines subject to 40 CFR part 60, subpart IIII are already required by subpart IIII to use diesel fuel that meets the requirements of 40 CFR 80.510(b).

The 2010 regulation specified that existing emergency engines at area sources of HAP that are residential, commercial, or institutional facilities were not subject to the RICE NESHAP requirements as long as the engines were limited to no more than 15 hours per year for emergency demand response. The EPA is specifying in the final rule that existing emergency engines at area sources of HAP that are residential, commercial, or institutional facilities are subject to the applicable requirements for stationary emergency engines in the RICE NESHAP if they operate or are contractually obligated to be available for more than 15 hours per year (up to a maximum of 100 hours per year) for emergency demand response, or they operate to mitigate local transmission and/or distribution limitations. Information provided by commenters on the 2010 regulation and the amendments proposed in June 2012 indicates that these engines typically operate less than 15 hours per year for emergency demand response.

For stationary emergency engines above 500 HP at major sources of HAP that were installed before June 12, 2006, prior to these final amendments, there was no emergency demand response provision and there was no time limit on the use of emergency engines for routine testing and maintenance in § 63.6640(f)(2)(ii). Those engines were not the focus of the 2010 RICE NESHAP amendments; therefore, the EPA did not make any changes to the requirements for those engines as part of the 2010 amendments. For consistency, the EPA is now also revising 40 CFR part 63, subpart ZZZZ to require owners and operators of stationary emergency engines above 500 HP at major sources of HAP installed prior to June 12, 2006, to limit operation of their engines for maintenance and testing and emergency demand response program to a total of 100 hours per year. These engines would also be required to use diesel fuel meeting the specifications of 40 CFR 80.510(b) beginning January 1, 2015, however, if the engine operates or is contractually obligated to be available for more than 15 hours per year. Any existing diesel fuel purchased (or otherwise obtained) prior to January 1, 2015 may be used until depleted. In addition to the fuel requirement, owners and operators of these engines must report the dates and times the engines operate for emergency demand response annually to the EPA, beginning with operation during the 2015 calendar year.

More detail regarding the public comments regarding emergency demand response and the EPA's responses can be found in the Response to Public Comments document available in the rulemaking docket.

C. Peak Shaving

In the June 7, 2012, proposal, the EPA proposed a temporary provision for existing stationary emergency engines located at area sources to apply the 50 hours per year that is allowed under § 63.6640(f) for non-emergency operation towards any non-emergency operation, including peak shaving. The peak shaving provision was proposed to expire in April 2017. As discussed further in section III.B, the EPA is not finalizing the proposed temporary 50-hour provision for existing stationary emergency engines located at area sources engaged in peak shaving and other non-emergency use as part of a financial arrangement with another entity. However, in consideration of the short time between this final rule and the May 3, 2013, or October 19, 2013, compliance dates for affected sources, this final rule includes a provision limiting the use of existing stationary emergency engines located at area sources to 50 hours per year prior to May 3, 2014, for peak shaving or non-emergency demand response to generate income for a facility, or to otherwise supply power as part of a financial arrangement with another entity if the engines are operated as part of a peak shaving (load management) program with the local distribution system operator and the power is provided only to the facility itself or to support the local distribution system. This extension provides additional time so that these sources that wish to engage in peak shaving can come into compliance with the applicable requirements for non-emergency engines.

D. Non-Emergency Stationary SI RICE Greater Than 500 HP Located at Area Sources

The EPA is finalizing amendments to the requirements that apply to existing stationary non-emergency 4-stroke SI RICE greater than 500 HP located at area sources of HAP emissions, which are generally natural gas fired engines.

The EPA is creating a subcategory for existing spark ignition engines located in sparsely populated areas. Engines located in remote areas that are not close to significant human activity may be difficult to access, may not have electricity or communications, and may be unmanned most of the time. The costs of the emission controls, testing, and continuous monitoring requirements may be unreasonable when compared to the HAP emission reductions that would be achieved, considering that the engines are in sparsely populated areas. Moreover, the location of these engines is such that there would be limited public exposure to the emissions. The EPA believes that establishing a subcategory for SI engines at area sources of HAP located in sparsely populated areas accomplishes the agency's goals and is adequate in protecting public health. The EPA is creating this subcategory using criteria based on the existing DOT classification system for natural gas pipelines. This system classifies locations based on their distance to natural gas pipelines covered by the Pipeline and Hazardous Materials Safety Administration regulations. The DOT system defines a class location unit as an onshore area that extends 220 yards or 200 meters on either side of the centerline of any continuous 1-mile (1.6 kilometers) length of natural gas pipeline. The DOT approach further classifies pipeline locations into Class 1 through Class 4 locations based on the number of buildings intended for human occupancy. A Class 1 location is defined as an offshore area or any class location unit that has 10 or fewer buildings intended for human occupancy. The DOT classification system also has special provisions for locations where buildings with four or more stories above ground are prevalent and locations that lie within 100 yards (91 meters) of either a building or a small, well-defined outside area (such as a playground, recreation area, outdoor theater, or other place of public assembly) that is occupied by 20 or more persons on at least 5 days a week for 10 weeks in any 12-month period. To be considered remote under this final rule, a source on a pipeline could not fall under these special provisions and, in addition, must be in a Class 1 location. For those engines not associated with pipelines, the EPA is using similar criteria. An engine would be considered to be in sparsely populated areas if within 0.25 mile radius of the engine there are 5 or fewer buildings intended for human occupancy.

Owners and operators of existing stationary non-emergency 4-stroke lean burn (4SLB) and 4SRB RICE greater than 500 HP at area sources that are in sparsely populated areas as described above would be required to perform the following:

- Change oil and filter every 2,160 hours of operation or annually, whichever comes first;
- Inspect spark plugs every 2,160 hours of operation or annually, whichever comes first, and replace as necessary; and
- Inspect all hoses and belts every 2,160 hours of operation or annually, whichever comes first, and replace as necessary.

Sources have the option to use an oil analysis program as described in § 63.6625(i) of the rule in order to extend the specified oil change requirement. The oil analysis must be performed at the same frequency specified for changing the oil in Table 2d of the rule. The analysis program must at a minimum analyze the following three parameters: Total Acid Number, viscosity, and percent water content. The condemning limits for these parameters are as follows: Total Acid Number increases by more than 3.0 milligrams of potassium hydroxide per gram from Total Acid Number of the oil when new; viscosity of the oil has changed by more than 20 percent from the viscosity of the oil when new; or percent water content (by volume) is greater than 0.5. If none of these condemning limits are exceeded, the engine owner or operator is not required to change the oil. If any of the limits are exceeded, the engine owner or operator must change the oil within 2 business days of receiving the results of the analysis; if the engine is not in operation when the results of the analysis are received, the engine owner or operator must change the oil within 2 business days or before commencing operation, whichever is later. The owner or operator must keep records of the parameters that are analyzed as part of the program, the results of the analysis, and the oil changes for the engine. The analysis program must be part of the maintenance plan for the engine.

Owners and operators of existing stationary 4SLB and 4SRB area source engines above 500 HP in sparsely populated areas would also have to operate and maintain the stationary RICE and aftertreatment control device (if any) according to the manufacturer's emission-related written instructions or develop their own maintenance plan, which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions.

Owners and operators of engines in sparsely populated areas would have to conduct a review of the surrounding area every 12 months to determine if the nearby population has changed. If the engine no longer meets the criteria for a sparsely populated area, the owner and operator must within 1 year comply with the emission standards specified below for populated areas.

For engines in populated areas, i.e., existing stationary 4SLB and 4SRB non-emergency engines greater than 500 HP at area sources that are located on DOT Class 2 through Class 4 pipeline segments or, for engines not associated with pipelines, that do not meet the 0.25 mile radius with 5 or less buildings criteria, the EPA is revising the requirements that were finalized in the 2010 rule. The EPA is adopting an equipment standard requiring the installation of a catalyst to reduce HAP emissions. Owners and operators of existing area source 4SLB non-emergency engines greater than 500 HP in populated areas would be required to install an oxidation catalyst. Owners and operators of existing area source 4SRB non-emergency engines greater than 500 HP in populated areas would be required to install NSCR. Owners and operators must conduct an initial test to demonstrate that the engine achieves at least a 93 percent reduction in CO emissions or a CO concentration level of 47 ppmvd at 15 percent O_2, if the engine is a 4SLB engine. Similarly, owners and operators must conduct an initial performance test to demonstrate that the engine achieves at least either a 75 percent CO reduction, a 30 percent THC reduction, or a CO concentration level of 270 ppmvd at 15 percent O_2 if the engine is a 4SRB engine. The initial test must consist of three test runs. Each test run must be of at least 15 minute duration, except that each test run conducted using appendix A to 40 CFR part 63, subpart ZZZZ must consist of one measurement cycle as defined by the method and include at least 2 minutes of test data phase measurement. To measure CO, emission sources must use the CO methods already specified in subpart ZZZZ, or appendix A to 40 CFR part 63, subpart ZZZZ. The THC testing

must be conducted using EPA Method 25A.

The owner or operator of both engine types must also use a high temperature shutdown device that detects if the catalyst inlet temperature is too high, or, alternatively, the owner or operator can monitor the catalyst inlet temperature continuously and maintain the temperature within the range specified in the rule. For 4SLB engines the catalyst inlet temperature must remain at or above 450 °F and at or below 1,350 °F. For 4SRB engines the temperature must be greater than or equal to 750 °F and less than or equal to 1,250 °F at the catalyst inlet.

Owners and operators must in addition to the initial performance test conduct annual checks of the catalyst to ensure proper catalyst activity. The annual check of the catalyst must at a minimum consist of one 15-minute run using the methods discussed above, except that each test run conducted using appendix A to 40 CFR part 63, subpart ZZZZ must consist of one measurement cycle as defined by the method and include at least 2 minutes of test data phase measurement. Owners and operators of 4SLB engines must demonstrate during the catalyst activity test that the catalyst achieves at least a 93 percent reduction in CO emissions or that the engine exhaust CO emissions are no more than 47 ppmvd at 15 percent O_2. Owners and operators of 4SRB engines must demonstrate during the catalyst activity check that their catalyst is reducing CO emissions by 75 percent or more, the CO concentration level at the engine exhaust is less than or equal to 270 ppmvd at 15 percent O_2, or THC emissions are being reduced by at least 30 percent.

If the emissions from the engine do not exceed the levels required for the initial test or annual checks of the catalyst, then the catalyst is considered to be working properly. If the emissions exceed the specified pollutant levels in the rule, the exceedance(s) is/are not considered a violation, but the owner or operator would be required to shut down the engine and take appropriate corrective action (e.g., repairs, clean or replace the catalyst, as appropriate). A follow-up test must be conducted within 7 days of the engine being started up again to demonstrate that the emission levels are being met. If the retest shows that the emissions continue to exceed the specified levels, the stationary RICE must again be shut down as soon as safely possible, and the engine may not operate, except for purposes of start-up and testing, until the owner/operator demonstrates through testing that the emissions do not exceed the levels specified.

E. Stationary CI RICE Certified to Tier Standards

The EPA is amending the requirements for any stationary CI engine certified to the Tier 3 standards in 40 CFR part 89 (Tier 2 for engines above 560 kilowatt (kW)) located at an area source and installed before June 12, 2006. The EPA is finalizing amendments to specify that any existing certified Tier 3 (Tier 2 for engines above 560 kW) CI engine that was installed before June 12, 2006, is in compliance with the RICE NESHAP. This amendment includes any existing stationary Tier 3 (Tier 2 for engines above 560 kW) certified CI engine located at an area source of HAP emissions. Without these amendments, Tier 3 engines, which were built to meet stringent emission standards, would not be able to comply with the applicable RICE NESHAP emission standards for existing engines without further testing and monitoring, and possible retrofit with further controls, due to differences in the emission standards and testing protocols in the RICE NESHAP versus the Tier 3 standards in 40 CFR part 89. However, an identical engine certified to the Tier 3 standards (or Tier 2 standards for engines above 560 kW) in 40 CFR part 89 that was installed after June 12, 2006, would not have to be retrofit in order to comply with the NESHAP. The EPA believes that the Tier 3 standards (Tier 2 for engines above 560 kW) are technologically stringent regulations and believes it is unnecessary to require further regulation of engines meeting these standards.

The EPA is also amending the requirements for existing stationary CI engines that are certified to the Tier 1 and Tier 2 standards in 40 CFR part 89, located at area sources of HAP, greater than 300 HP and subject to a state or local rule that requires the engine to be replaced. The EPA does not think it is appropriate to require emission controls on a stationary CI engine that is going to be retired only a short time after the rule goes into effect. These engines (equipped with aftertreatment) could end up being in operation for less than 2 years or at most only 5 years before having to be replaced with a certified Tier 4 engine. It would not be reasonable to require the engine owner to invest in costly controls and monitoring equipment for an engine that will be replaced shortly after the installation of the controls. Consequently, the EPA is allowing these engines to meet management practices from the applicable May 3, 2013, compliance date until January 1, 2015, or 12 years after installation date (whichever is later), but not later than June 1, 2018, after which time the CO emission standards in Table 2d of 40 CFR part 63, subpart ZZZZ) apply. The management practices include requirements for when to inspect and replace the engine oil and filter, air cleaner, hoses and belts. The complete details of which management practices are required are shown in Table 2d of the rule. Owners and operators of these existing stationary CI engines located at area sources of HAP emissions that intend to meet management practices rather than the emission limits prior to January 1, 2015, or 12 years after installation date, but not later than June 1, 2018, must submit a notification by March 3, 2013, stating that they intend to use this provision and identifying the state or local regulation that the engine is subject to.

F. Definition for Remote Areas of Alaska

The RICE NESHAP amendments finalized in 2010 specified less stringent requirements for existing non-emergency CI engines at area sources located in remote areas of Alaska. Remote areas are defined under the 2010 rule as those not accessible by the FAHS. In this action, the EPA is expanding the definition of remote areas of Alaska to extend beyond areas that are not accessible by the FAHS. The EPA is expanding the current definition because some areas that are accessible by the FAHS face the same challenges as areas that are not accessible, including high energy costs, extreme weather conditions, lengthy travel times, inaccessibility, and very low population density. Many of these areas are not connected to the electric grid and rely on back up diesel generation to support fluctuating renewable energy systems. The energy supply system is another area that is particularly different in Alaska compared to the rest of the country where the majority of customers are connected to the grid. These final amendments specify that existing stationary CI engines at area sources of HAP in areas of Alaska that are accessible by the FAHS and that meet all of the following criteria will also be considered remote and subject to management practices under the rule:

- The stationary CI engine is located in an area not connected to the Alaska Railbelt Grid,
- At least 10 percent of the power generated by the engine per year is used for residential purposes, and
- The generating capacity of the area source is less than 12 MW, or the engine

is used exclusively for backup power for renewable energy.

The EPA is limiting the remote classification to engines that are used at least partially for residential purposes, where the impact of higher energy costs is of greatest concern. The classification is further limited to sources that are used infrequently as backup for renewable power, or that are at smaller capacity facilities, which are generally in more sparsely populated areas.

G. Requirements for Offshore Vessels

The EPA is revising the requirements in the RICE NESHAP for existing non-emergency CI RICE greater than 300 HP on offshore vessels that are area sources of HAP. Engines on vessels on the OCS in certain circumstances become subject to the provisions of the RICE NESHAP as a result of the operation of the OCS regulations at 40 CFR part 55. The rationale for this revision is discussed further in section III.D. The EPA is finalizing the following management practice requirements for existing non-emergency CI RICE greater than 300 HP on offshore vessels that are area sources of HAP:

- Change oil every 1,000 hours of operation or annually, whichever comes first, except that sources can extend the period for changing the oil if the oil is part of an oil analysis program as discussed below and the condemning limits are not exceeded;
- Inspect and clean air filters every 750 hours of operation or annually, whichever comes first, and replace as necessary;
- Inspect fuel filters and belts, if installed, every 750 hours of operation or annually, whichever comes first, and replace as necessary; and
- Inspect all flexible hoses every 1,000 hours of operation or annually, whichever comes first, and replace as necessary.

These sources may use an oil analysis program in order to extend the specified oil change requirement. The analysis program must at a minimum analyze the following three parameters: Total Base Number, viscosity and percent water content. The analysis must be conducted at the same frequency specified for changing the engine oil. If the condemning limits provided below are not exceeded, the engine owner or operator is not required to change the oil. If any of the condemning limits are exceeded, the engine owner or operator must change the oil within two business days or before continuing to use the engine, whichever is later. The condemning limits are as follows:

- Total Base Number is less than 30 percent of the Total Base Number of the oil when new; or
- Viscosity of the oil has changed by more than 20 percent from the viscosity of the oil when new; or
- Percent water content (by volume) is greater than 0.5.

Owners and operators of these existing stationary CI RICE must develop a maintenance plan that specifies how the management practices will be met and keep records to demonstrate that the required management practices are being met.

H. Miscellaneous Corrections and Revisions

The EPA is making some minor corrections and clarifications to the stationary engine rules to address miscellaneous issues. The revisions are as follows:

- Revising Tables 1b and 2b of 40 CFR part 63, subpart ZZZZ to correct language requiring the pressure drop to be at plus or minus 10 percent of 100 percent load for all engines. The engines that were regulated in 2010 are not subject to the load requirements and therefore the EPA is correcting these tables to make this clear.
- Adding a footnote to Table 1b of 40 CFR part 63, subpart ZZZZ stating that sources can petition the Administrator for a different temperature range consistent with Table 2b of the rule.
- Correcting rows 8 and 10 in Table 2d of 40 CFR part 63, subpart ZZZZ to indicate that the requirements apply to non-emergency, non-black start stationary RICE greater than 500 HP that are 4SLB and 4SRB that operate more than 24 hours per year, as intended in the original rule.
- Revising the language in § 63.6625(b) of 40 CFR part 63, subpart ZZZZ that states "* * * in paragraphs (b)(1) through (5) of this section" to "in paragraphs (b)(1) through (6) of this section."
- Changing Tables 2c and 2d of 40 CFR part 63, subpart ZZZZ, where it currently specifies to inspect air cleaner, to also specify that it must be replaced as necessary.
- Revising § 63.6620(b) of 40 CFR part 63, subpart ZZZZ to indicate that testing must be conducted within plus or minus 10 percent of 100 percent load for stationary RICE greater than 500 HP located at a major source (except existing non-emergency CI stationary RICE greater than 500 HP located at a major source) that are subject to testing.
- Specifying that, as was intended in the rule adding these requirements, the operating limitations (pressure drop and catalyst inlet temperature) in Tables 1b and 2b of 40 CFR part 63, subpart ZZZZ do not have to be met during startup.
- For consistency, and as provided in the original RICE NESHAP for other stationary RICE, clarifying in 40 CFR part 63, subpart ZZZZ that the existing stationary RICE regulated in 2010 (i.e., engines constructed before June 12, 2006, that are less than or equal to 500 HP located at major sources or engines located at area sources) must burn landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis in order to qualify as a landfill or digester gas engine under the rule.
- Clarifying § 60.4207(b) of 40 CFR part 60, subpart IIII to specify that owners and operators of stationary CI engines less than 30 liters per cylinder that are subject to the subpart that use diesel fuel must use diesel fuel that meets the requirements of 40 CFR 80.510(b), except owners and operators may use up any diesel fuel acquired prior to October 1, 2010, that does not meet the requirements of 40 CFR 80.510(b) for nonroad diesel fuel.
- Adding appendix A to 40 CFR part 63, subpart ZZZZ, which includes procedures that can be used for measuring CO emissions from existing stationary 4SLB and 4SRB stationary RICE above 500 HP located at area sources of HAP that are complying with the emission limits in Table 2d of 40 CFR part 63, subpart ZZZZ.
- Reinstating the footnotes for Table 2 of 40 CFR part 60, subpart JJJJ. The footnotes were inadvertently removed when the rule was amended on June 28, 2011 (76 FR 37954).
- Adding "part 60" in Table 4 of the NESHAP, in row 2 where it refers to 40 CFR appendix A.
- Clarifying in § 63.6625(a) of 40 CFR part 63, subpart ZZZZ that a continuous emission monitoring system is only required to be installed at the outlet of the control device for engines that are complying with the requirement to limit the concentration of CO.
- Adding definitions of terms used in Equation 4 of § 63.6620 of 40 CFR part 63, subpart ZZZZ.
- Clarifying that, as was intended in the rule adding these requirements, all of the standards for stationary SI RICE in § 60.4231(b) of 40 CFR part 60, subpart JJJJ are for stationary SI RICE that use gasoline.
- Clarifying that, as was intended in the rule adding these requirements, all of the standards for stationary SI RICE in § 60.4231(c) of 40 CFR part 60, subpart JJJJ are for stationary SI RICE that are rich burn engines that use liquified petroleum gas (LPG).

• Clarifying that, as was intended in the rule adding these requirements, all of the standards for stationary SI RICE in § 60.4231(d) of 40 CFR part 60, subpart JJJJ are for stationary SI RICE that are not gasoline engines or rich burn engines that use LPG.

• Clarifying in § 63.6625(b)(1) and the entries for § 63.8(c)(1)(i) and (iii) in Table 8 of 40 CFR part 63, subpart ZZZZ that a startup, shutdown, and malfunction plan is not required for a continuous parameter monitoring system.

• Clarifying in the entry for § 63.10(b)(1) in Table 8 of 40 CFR part 63, subpart ZZZZ that the most recent two years of data do not have to be retained on site.

• Revising footnote 2 of Table 2c and footnote 1 of Table 2d of 40 CFR part 63, subpart ZZZZ to include a reference to § 63.6625(j), as was intended in the rule addressing these requirements.

III. Summary of Significant Changes Since Proposal

A. Emergency Demand Response and Reliability

The EPA proposed to limit operation of emergency stationary RICE as part of an emergency demand response program to within the 100 hours per year that is already permitted for maintenance and testing of the engines. The EPA proposed that owners and operators of stationary emergency engines could operate the engines for emergency demand response when the Reliability Coordinator, or other authorized entity as determined by the Reliability Coordinator, has declared an EEA Level 2 as defined in the NERC Reliability Standard EOP–002–3, Capacity and Energy Emergencies, plus during periods where there is a deviation of voltage or frequency of 5 percent or more below standard voltage or frequency. After considering public comments received on the proposed rule, the EPA is finalizing the proposed amendment to limit operation for maintenance and testing and emergency demand response to no more than 100 hours per year.

The EPA received some comments in support of the provision for emergency demand response operation, while other commenters opposed the limitation. The commenters who supported the provision noted that the engines are rarely called for emergency demand response, and that the EPA has limited the emergency demand response operation to emergency situations where a blackout is imminent. The commenters also noted that the public health impacts created by a widespread power outage outweigh the air quality impacts from the engines. The EPA agrees with the commenters that it is appropriate to include a provision for operation of emergency engines for a limited number of hours per year as part of emergency demand response programs to help prevent grid failure or blackouts. Preventing stationary emergency engines from being able to qualify and participate in emergency demand response programs without having to apply aftertreatment could force owners and operators to remove their engines from these programs, which could impair the ability of regional transmission organizations and independent system operators to use these relatively small, quick-starting and reliable sources of energy to protect the reliability of their systems.

The commenters who opposed the provision for demand response provided no significant argument that the conditions under which these engines would be permitted to operate for emergency demand response would not be emergency conditions. Commenters who opposed the provision were concerned about the air quality and health impacts of emissions from stationary engines. The commenters were concerned that recent actions by the Federal Energy Regulatory Commission (FERC) that impact demand response compensation in organized wholesale energy markets will greatly increase the amount of demand response participating in organized wholesale capacity markets. In response to the commenters, the EPA notes that, prior to the 2013 compliance dates for existing engines, there are no limitations on the hours of operation for those engines. The standards that go into effect in 2013 will for the first time establish requirements for these engines, including limitations on their hours of operation in certain situations such as emergency demand response, and ULSD fuel requirements which will reduce HAP emissions from the engines. Regarding the FERC regulations and their effect on use of demand response in capacity markets, these are comments more appropriately directed towards the FERC. As noted above, the emergency demand response situations during which the emergency engines may be used for a limited number of hours per year are appropriately considered emergency situations.

Commenters were also concerned that these engines would be called to operate for demand response on high ozone days, further contributing to nonattainment with ozone standards. However, other commenters noted that emergency demand response events do not predominantly occur on ozone exceedance days. These commenters also note that some of the commenters opposing use of emergency engines during emergency demand response would benefit by such a limitation because other emission sources may be used instead of the emergency engines, including sources that some of these commenters may operate, and that the effect on total emissions of using these alternative emission sources is not clear. Concerns about contribution to ozone nonattainment by stationary engines can be addressed through area-specific requirements such as state-based State Implementation Plans that would be directed towards ozone nonattainment areas. More detail regarding the public comments and the EPA's responses can be found in the Response to Public Comments document available in the rulemaking docket.

As mentioned in the previous paragraph, in response to the concerns about the air quality impact of emissions from emergency engines operating in emergency demand response programs, and based on public comments received on the proposed rule, the EPA is finalizing a requirement for owners and operators of existing emergency CI stationary RICE with a site rating of more than 100 brake HP and a displacement of less than 30 liters per cylinder that use diesel fuel and operate or are contractually obligated to be available for more than 15 hours per year (up to a maximum of 100 hours per year) for emergency demand response to use diesel fuel that meets the requirements in 40 CFR 80.510(b) for nonroad diesel fuel. This fuel requirement also applies to owners and operators of new emergency CI stationary RICE with a site rating of more than 500 brake HP with a displacement of less than 30 liters per cylinder located at a major source of HAP that use diesel fuel and operate or are contractually obligated to be available for more than 15 hours per year (up to a maximum of 100 hours per year) for emergency demand response. Owners and operators must begin meeting this ULSD fuel requirement on January 1, 2015, except that any existing diesel fuel purchased (or otherwise obtained) prior to January 1, 2015, may be used until depleted. As noted by commenters on the proposed amendments and as discussed in section II.B, requiring the use of diesel fuel meeting the requirements of 40 CFR 80.510(b) is expected to reduce the HAP emissions significantly from the engines compared to emissions resulting from use of unregulated diesel fuel. The fuel

requirement begins on January 1, 2015, in order to give affected sources appropriate lead time to institute these new requirements and make any physical adjustments to engines and other facilities like tanks or containment structures, as well as any needed adjustments to contracts and other business activities, that may be necessitated by these new requirements.

The final amendments also require owners and operators of emergency stationary RICE larger than 100 HP that operate or are contractually obligated to be available for more than 15 hours per year (up to a maximum of 100 hours per year) for emergency demand response to submit an annual report to the EPA documenting the dates and times that the emergency stationary RICE operated for emergency demand response, beginning with the 2015 calendar year. Commenters on the proposed amendments recommended that the EPA gather information on the impacts of the emissions from emergency engines during emergency demand response situations. The EPA agrees that a reporting requirement will increase the EPA's ability to ensure that these engines are operating in compliance with the regulations and that it will provide further information regarding the impacts of these engines on emissions. In response to these comments, the EPA is establishing a requirement to annually report to EPA the engine location and duration of operation for emergency demand response. This information will be used by the EPA, as well as state and local air pollution control agencies, to assess the health impacts of the emissions from these engines and to aid the EPA in ensuring that these engines comply with the regulations. Additional discussion of the rationale for the fuel and reporting requirements, as well as responses to other significant comments regarding emergency engines engaged in emergency demand response, can be found in the Response to Public Comments document in the docket.

Public commenters, in particular the National Rural Electric Cooperative Association (NRECA), indicated that the proposed EEA Level 2 and 5 percent voltage or frequency deviation triggers did not account for situations when the local balancing authority or transmission operator for the local electric system has determined that electric reliability is in jeopardy, and recommended that the EPA include additional situations where the local transmission and distribution system operator has determined that there are conditions that could lead to a blackout for the local area. The comments from NRECA indicated that rural distribution lines are not configured in a typical grid pattern, but instead have distribution lines that can run well over 50 miles from a substation and regularly extend 15 miles or longer. During periods of exceptionally heavy stress within the region or sub-region, electricity from regional power generators may not be available because of transmission constraints, according to the commenter. The commenter indicated that in many cases, there may be only one transmission line that feeds the rural distribution system, and no alternative means to transmit power into the local system.

In response to those comments and in recognition of the unique challenges faced by the local transmission and distribution system operators in rural areas, the EPA is specifying in the final rule that existing emergency stationary RICE at area sources can be used for 50 hours per year as part of a financial arrangement with another entity if all of the following conditions are met:

- The engine is dispatched by the local balancing authority or local transmission and distribution system operator.
- The dispatch is intended to mitigate local transmission and/or distribution limitations so as to avert potential voltage collapse or line overloads that could lead to the interruption of power supply in a local area or region.
- The dispatch follows reliability, emergency operation or similar protocols that follow specific NERC, regional, state, public utility commission or local standards or guidelines.
- The power is provided only to the facility itself or to support the local transmission and distribution system.
- The owner or operator identifies and records the specific NERC, regional, state, public utility commission or local standards or guidelines that are being followed for dispatching the engine. The local balancing authority or local transmission and distribution system operator may keep these records on behalf of the engine owner or operator.

Engines operating in systems that do not meet the conditions described here will not be considered emergency engines if they operate for these purposes as part of a financial arrangement with another entity.

Stationary emergency CI RICE with a site rating of more than 100 brake HP and a displacement of less than 30 liters per cylinder located at area sources that operate for this purpose are also required to use diesel fuel meeting the specifications of 40 CFR 80.510(b) beginning January 1, 2015, except that any existing diesel fuel purchased (or otherwise obtained) prior to January 1, 2015, may be used until depleted. Owners and operators of these engines are also required to report the dates and times the engines operated for this purpose annually to the EPA, beginning with operation during the 2015 calendar year. The report must also identify the entity that dispatched the engine and the situation that necessitated the dispatch of the engine. Further discussion of the rationale for the changes is available in the Response to Public Comments document in the docket.

B. Peak Shaving

The EPA proposed a temporary provision for existing stationary emergency engines located at area sources to apply the 50 hours per year that is allowed under § 63.6640(f) for non-emergency operation towards any non-emergency operation, including operation as part of a financial agreement with another entity. The peak shaving provision was proposed to expire in April 2017. The purpose of the proposed provision for peak shaving was to give sources an additional resource for maintaining reliability while facilities are coming into compliance with the NESHAP From Coal and Oil-Fired Electric Utility Steam Generating Units (77 FR 9304, February 16, 2012). Based on public comments received on the proposal, the EPA is not finalizing the proposed provision for peak shaving in this action. As noted by the commenters, operation for peak shaving does not fairly come under the definition of emergency use as it is designed to increase capacity in the system, rather than responding to an emergency situation such as a blackout or imminent brownout. The EPA believes that peak shaving activity and other activities designed to increase capacity should be treated as part of long term capacity planning, not as use akin to emergencies. The EPA agrees with commenters who state that allowance for emergency engines to be used for peak shaving could well lead to increased use of these engines, particularly in situations that are not emergency situations. The EPA also agrees that use of internal combustion engines for peak shaving is not based on emergency use, but instead is generally based on the economic benefit gained by operating the engine rather than another power source. The EPA agrees with the commenters that there is not sufficient information on the record to show that these engines are needed to maintain reliability while facilities are coming

into compliance with the NESHAP From Coal and Oil-Fired Electric Utility Steam Generating Units, and the commenters who supported the limited temporary provision did not provide information to show that rule would cause reliability issues that necessitate the operation of these engines. The EPA believes that given this information, it is appropriate to treat use of internal combustion engines as peak power units not as emergency use but as normal power generation, and thus believes it is appropriate to require emissions aftertreatment requirements (or similar controls as appropriate for non-emergency engines) for engines engaging in these activities for compensation. Further discussion is available in the Response to Public Comments document in the docket.

However, in consideration of the short time between this final rule and the May 3, 2013, or October 19, 2013 compliance dates for affected sources, this final rule permits the use of existing stationary emergency engines located at area sources for 50 hours per year through May 3, 2014 for peak shaving or non-emergency demand response to generate income for a facility, or to otherwise supply power as part of a financial arrangement with another entity if the engines are operated as part of a peak shaving (load management) program with the local distribution system operator and the power is provided only to the facility itself or to support the local distribution system. Owners and operators of these engines, which have heretofore not been regulated, may have taken actions based on the June 7, 2012, proposal that would now leave them in danger of being in noncompliance with the applicable requirements for the engine in the RICE NESHAP.

C. Non-Emergency Stationary SI RICE Greater Than 500 HP Located at Area Sources

The EPA proposed to require existing stationary non-emergency 4-stroke SI RICE greater than 500 HP located at area sources of HAP that are in sparsely populated areas to meet management practices. The proposed management practices required the engine owner and operator to change the oil and filter and inspect spark plugs, hoses and belts every 1,440 hours of operation or annually, whichever comes first. The proposed management practices were based on similar requirements for existing non-emergency stationary SI RICE smaller than 500 HP. The EPA received public comments indicating that the interval for performing the management practices for engines larger than 500 HP should be every 2,160 hours of operation or annually, whichever comes first. Commenters indicated that larger engines have increased capabilities compared to smaller size engines, which allows engines to extend the maintenance interval. Larger engines have increased oil capacities, use improved oil grades/synthetics, and use oil sweetening systems, according to the commenters. Commenters also noted that larger engines use better quality, more expensive spark plugs that last longer than 1,440 hours, and that less frequent maintenance intervals reduce the environmental impacts associated with disposing waste oils and traveling to remote locations. The EPA agrees with the arguments presented by the commenters. Therefore, in this final rule, EPA is requiring engine owners and operators to change the oil and filter and inspect spark plugs, hoses and belts every 2,160 hours of operation or annually, whichever comes first.

For existing stationary non-emergency SI 4SRB RICE that are in populated areas, the EPA proposed an equipment standard that required the installation of NSCR to reduce HAP emissions. The proposed rule required these engines to demonstrate that the catalyst achieves at least a 75 percent CO reduction or a 30 percent THC reduction. The EPA is retaining this requirement in this final rule, but is adding another option in response to public comments that allows the owner and operator of the engine to demonstrate that the catalyst achieves a CO concentration level of 270 ppmvd at 15 percent O_2. As noted by the public comments, this represents a 75 percent reduction from typical uncontrolled emissions from existing stationary non-emergency SI 4SRB RICE and is the CO standard required for new SI 4SRB engines in the NSPS for stationary SI engines. The EPA is also clarifying that, as was intended in the original proposal, engines located in Class 4 locations are not considered remote. More detail regarding the public comments and the rationale for these changes can be found in the Response to Public Comments document, which is available in the docket for this rulemaking.

D. Definition for Remote Areas of Alaska

The EPA proposed to expand the definition of remote areas of Alaska to extend beyond areas that are not accessible by the FAHS. Specifically, the EPA proposed that areas of Alaska that are accessible by the FAHS and that met all of the following criteria would also be considered remote and subject to management practices under the rule: (1) The stationary CI engine is located in an area not connected to the Alaska Railbelt Grid; (2) at least 10 percent of the power generated by the engine per year is used for residential purposes; and (3) the generating capacity of the area source is less than 12 MW, or the engine is used exclusively for backup power for renewable energy and is used less than 500 hours per year on a 10-year rolling average. After considering the public comments received on the proposed criteria, the EPA is finalizing the first two criteria as proposed, but finalizing a slightly different third criterion. In this final rule, existing CI engines at area sources of HAP are considered remote if they meet the first and second criteria above and they are either at a source with a generating capacity less than 12 MW, or used exclusively for backup power for renewable energy. Based on public comments received on the proposal, the EPA is not finalizing the limitation that the engine be used less than 500 hours per year on a 10-year rolling average. Commenters indicated that basing the applicability on the previous 10 years of operation would ignore recent investments in renewable energy that have significantly decreased engine hours of operation in recent years. The EPA is also defining ''backup power for renewable energy'' in this final rule as engines that provide backup power to a facility that generates electricity from renewable energy resources, as that term is defined in Alaska Statute 42.45.045(l)(5). The rationale for these changes can be found in the Response to Public Comments document available in the docket.

E. Requirements for Offshore Vessels

The RICE NESHAP does not on its face apply to mobile sources, including marine vessels. However, the regulations applicable to sources on the OCS, codified at 40 CFR part 55, specify that vessels are OCS sources when they are (1) permanently or temporarily attached to the seabed and erected thereon and used for the purpose of exploring, developing or producing resources there from, within the meaning of section 4(a)(1) of the OCS Lands Act (43 U.S.C. 1331, *et seq.*); or (2) physically attached to an OCS facility, in which case only the stationary sources aspects of the vessels will be regulated. 40 CFR 55.2. The OCS regulations provide that NESHAP requirements apply to a vessel that is an OCS source where the provisions are ''rationally related to the attainment and maintenance of the federal or state ambient air quality standards or the

requirements of part C of title I of the Act.'' 40 CFR 55.13(e).

The EPA received comments during the public comment period for the June 7, 2012, proposal recommending that the RICE NESHAP be amended such that for any existing non-emergency CI RICE above 300 HP on offshore vessels on the OCS that become subject to the RICE NESHAP as a result of the operation of the OCS regulations (40 CFR part 55), such engines may meet the NESHAP through management practices rather than numeric emission limits. This amendment was not contained or contemplated in the June 7, 2012, proposal. However, the comments indicated several significant issues related to application of the NESHAP to regulation of existing marine vessel engines located in the OCS as a result of the OCS regulations; in particular, whether the numerical standards applicable to other CI engines located at area sources (marine vessels located in the OCS are generally located at area sources) are technologically feasible for existing marine engines located in the OCS. Some commenters noted specific technological issues relevant to engines on marine vessels in the OCS. The commenters indicated that emission controls for existing CI RICE to meet the NESHAP may be technically infeasible due to weight and space constraints, catalyst fouling from the low-load engine operation required by the U.S. Coast Guard, safety concerns regarding engine backpressure and lack of catalyst vendor experience with retrofitting. Commenters suggested that, to the extent marine vessel engines become subject to the NESHAP as a result of the OCS regulations, these engines should be subject to GACT requirements that the commenters believe are more appropriate for these types of engines. The commenters indicated that management practices similar to those currently required in the rule for existing non-emergency stationary CI RICE smaller than 300 HP are more appropriate as GACT for existing non-emergency stationary CI RICE above 300 HP on vessels operating on the OCS.

Based on these comments, the EPA published a reopening of the comment period to take further comment on whether the RICE NESHAP should be revised to require management practices for these vessels (77 FR 60341, October 3, 2012). Based on the comments received during the two comment periods, the EPA agrees with the commenters that management practices are more reasonable as GACT for existing non-emergency stationary CI RICE larger than 300 HP on vessels operating on the OCS and is finalizing management practices for these engines. The EPA did not receive any public comments indicating that HAP emission controls were generally available and had been demonstrated for the large engines on the vessels. The final management practices include changing the oil every 1,000 hours of operation or annually, whichever comes first; inspecting and cleaning air filters every 750 hours of operation or annually, whichever comes first, and replacing as necessary; inspecting fuel filters and belts, if installed, every 750 hours of operation or annually, whichever comes first, and replacing as necessary; and inspecting all flexible hoses every 1,000 hours of operation or annually, whichever comes first, and replacing as necessary. Facilities have the option of using an oil analysis program to extend the oil change requirement. Additional discussion of the rationale for these changes can be found in the Response to Public Comments document available in the docket.

IV. Summary of Environmental, Energy and Economic Impacts

A. What are the air quality impacts?

The EPA estimates that the rule with the final amendments incorporated will reduce emissions from existing stationary RICE as shown in Table 4 of this preamble. The emissions reductions the EPA previously estimated for the 2010 amendments to the RICE NESHAP are shown for comparison. Reductions are shown for the year 2013, which is the first year the final RICE NESHAP will be implemented for existing stationary RICE.

TABLE 4—SUMMARY OF REDUCTIONS FOR EXISTING STATIONARY RICE

Pollutant	Emission Reductions (tpy) in the year 2013			
	2010 Final rule		2010 Final rule with these final amendments	
	CI	SI	CI	SI
HAP	1,014	6,008	1,005	1,778
CO	14,342	109,321	14,238	22,211
PM	2,844	N/A	2,818	N/A
NO_X	N/A	96,479	N/A	9,648
VOC	27,395	30,907	27,142	9,147

The EPA estimates that more than 900,000 stationary CI engines will be subject to the rule in total, but only a small number of stationary CI engines are affected by the final amendments in this action. The EPA did not estimate any changes in the reductions from the 2010 rule for the amendments associated with emergency engines. To determine emissions from emergency engines for the 2010 rule, the EPA estimated that these types of engines would on average operate for 50 hours per year. The average hours of operation for emergency engines is not expected to change based on the final amendments and 50 hours per year is still believed to be representative of average emergency engine operation. Information provided by commenters demonstrated that these engines have been operated very infrequently for emergency demand response events.[8] Therefore, the emissions previously calculated remain appropriate.

It is estimated that approximately 330,000 stationary SI engines will be subject to the rule in total; however, only a subset of stationary SI engines are affected by the final amendments in this action. The decrease in estimated reductions for SI engines is primarily due to final amendments to the requirements for existing 4SRB and 4SLB SI engines larger than 500 HP at area sources of HAP that are in remote areas. Those engines were required by the 2010 rule to meet emission limits that were expected to require the installation of aftertreatment to reduce emissions; under these final amendments, those engines are required

[8] See document number EPA–HQ–OAR–2008–0708–1142 in the rulemaking docket.

to meet management practices that would not require the installation of aftertreatment. Further information regarding the estimated reductions of this final rule can be found in the memorandum titled, "RICE NESHAP Reconsideration Final Amendments—Cost and Environmental Impacts," which is available in the docket (EPA–HQ–OAR–2008–0708). The EPA did not estimate any impacts associated with the minor changes to the NSPS for stationary CI and SI engines.

B. What are the cost impacts?

The final amendments are expected to reduce the overall cost of the original 2010 RICE NESHAP amendments. The EPA estimates that with these final amendments incorporated, the cost of the rule for existing stationary RICE will be as shown in Table 5 of this preamble. The costs the EPA previously estimated for the 2010 amendments to the RICE NESHAP are shown for comparison. The costs that were previously estimated are shown in the original year ($2008 for CI and $2009 for SI), as well as updated to 2010 dollars.

TABLE 5—SUMMARY OF COST IMPACTS FOR EXISTING STATIONARY RICE

Engine	2010 Final Rule		2010 Final Rule with these Final Amendments
Total Annual Cost			
SI	$253 million ($2009)	$251 million ($2010)	$115 million ($2010).
CI	$373 million ($2008)	$375 million ($2010)	$373 million ($2010).
Total Capital Cost			
SI	$383 million ($2009)	$380 million ($2010)	$103 million ($2010).
CI	$744 million ($2008)	$748 million ($2010)	$740 million ($2010).

Further information regarding the estimated cost impacts of the final amendments, including the cost of the final amendments in 2010 dollars, can be found in the memorandum titled, "RICE NESHAP Reconsideration Final Amendments—Cost and Environmental Impacts," which is available in the docket (EPA–HQ–OAR–2008–0708). The EPA did not estimate costs associated with the changes to the NSPS for stationary CI and SI engines. The changes to the NSPS are minor and are not expected to impact the costs of those rules.

C. What are the benefits?

Emission controls installed to meet the requirements of this final rule will generate benefits by reducing emissions of HAP as well as criteria pollutants and their precursors, including CO, NO_X and VOC. NO_X and VOC are precursors to $PM_{2.5}$ (particles smaller than 2.5 microns) and ozone. The criteria pollutant benefits are considered co-benefits for this rule. For this final rule, the EPA was only able to quantify the health co-benefits associated with reduced exposure to $PM_{2.5}$ from emission reductions of NO_X and directly emitted $PM_{2.5}$. The EPA has not re-estimated the benefits from the proposal for this final rule because the emission reductions have not changed since the reconsideration proposal.[9]

The EPA previously estimated that the monetized co-benefits in 2013 of the stationary CI NESHAP would be $940 million to $2,300 million (2008 dollars) at a 3-percent discount rate and $850 million to $2,100 million (2008 dollars) at a 7-percent discount rate.[10] For stationary SI engines, EPA previously estimated that the monetized co-benefits in 2013 would be $510 million to $1,200 million (2009 dollars) at a 3-percent discount rate) and $460 million to $1,100 million (2009 dollars) at a 7-percent discount rate.[11]

The final amendments are expected to reduce the overall emission reductions of the rules, primarily due to the changes to requirements for engines in remote areas. In addition to revising the anticipated emission reductions, the EPA has also updated the methodology used to calculate the co-benefits to be consistent with methods used in more recent rulemakings, which is summarized below and discussed in more detail in the CI and SI Final Reconsideration RIAs, the RIAs for this rulemaking. The EPA estimates the monetized co-benefits of the final amendments of the CI NESHAP in 2013 to be $770 million to $1,900 million (2010 dollars) at a 3-percent discount rate and $690 million to $1,700 million (2010 dollars) at a 7-percent discount rate. For SI engines, the EPA estimates the monetized co-benefits of the final amendments in 2013 to be $62 million to $150 million (2010 dollars) at a 3-percent discount rate and $55 million to $140 million (2010 dollars) at a 7-percent discount rate.

Using alternate relationships between $PM_{2.5}$ and premature mortality supplied by experts, higher and lower co-benefits estimates are plausible, but most of the expert-based estimates fall between

[9] Since the June 7, 2012 reconsideration proposal, the EPA has made several updates to the approach used to estimate mortality and morbidity benefits, as demonstrated in the RIA for the PM NAAQS. Changes include applying the concentration-response functions from more recent epidemiology studies, adding some health endpoints, and updating population data. Although the EPA has not re-estimated the benefits for this rule by applying these changes, we anticipate that the rounded benefits estimated for this rule are unlikely to be very different than those provided here. Specifically, we anticipate that the changes that would likely lead to small increases in the benefits would likely be offset by changes that would likely lead to small decreases in the benefits. References for the RIA for the PM NAAQS are: (1) U.S. Environmental Protection Agency (U.S. EPA). 2012a. Regulatory Impact Analysis for the Proposed Revisions to the National Ambient Air Quality Standards for Particulate Matter. EPA–452/R–12–003. Office of Air Quality Planning and Standards, Health and Environmental Impacts Division. June. Available at *http://www.epa.gov/ttnecas1/regdata/RIAs/PMRIACombinedFile_Bookmarked.pdf*. (2) U.S. Environmental Protection Agency (U.S. EPA). 2012b. Regulatory Impact Analysis for the Final Revisions to the National Ambient Air Quality Standards for Particulate Matter. EPA–452/R–12–003. Office of Air Quality Planning and Standards, Health and Environmental Impacts Division. December. Available at *http://www.epa.gov/pm/2012/finalria.pdf*.

[10] U.S. Environmental Protection Agency. 2010. *Regulatory Impact Analysis (RIA) for Existing Stationary Compression Ignition Engines NESHAP: Final Draft.* Research Triangle Park, NC. February. *http://www.epa.gov/ttn/ecas/regdata/RIAs/CIRICENESHAPRIA2-17-0cleanpublication.pdf*.

[11] U.S. Environmental Protection Agency. 2010. *Regulatory Impact Analysis (RIA) for Existing Stationary Spark Ignition (SI) RICE NESHAP: Final Report.* Research Triangle Park, NC. August. *http://www.epa.gov/ttn/ecas/regdata/RIAs/riceriafinal.pdf*.

these two estimates.[12] A summary of the monetized co-benefits estimates for CI and SI engines at discount rates of 3-percent and 7-percent is in Table 6 of this preamble.

TABLE 6—SUMMARY OF THE MONETIZED $PM_{2.5}$ CO-BENEFITS FINAL AMENDMENTS TO THE NESHAP FOR STATIONARY CI AND SI ENGINES

[Millions of 2010 dollars] [a] [b]

Pollutant	Emission reductions (tons per year)	Total monetized co-benefits (3 percent discount)	Total monetized co-benefits (7 percent discount)
Original 2010 Final Rules [c]			
Stationary CI Engines:			
Total Benefits	2,844 $PM_{2.5}$, 27,395 VOC	$950 to $2,300	$860 to $2,100.
Stationary SI Engines:			
Total Benefits	96,479 NO_X, 30,907 VOC	$510 to $1,300	$470 to $1,100.
2010 Final Rules With These Final Amendments			
Stationary CI Engines:			
Directly emitted $PM_{2.5}$	2,818	$770 to $1,900	$690 to $1,700.
Stationary SI Engines:			
NO_X	9,648	$62 to $150	$55 to $140.

[a] All estimates are for the analysis year (2013) and are rounded to two significant figures so numbers may not sum across rows. The total monetized co-benefits reflect the human health benefits associated with reducing exposure to $PM_{2.5}$ through reductions of $PM_{2.5}$ precursors, such as NO_X and directly emitted $PM_{2.5}$. It is important to note that the monetized co-benefits do not include reduced health effects from exposure to HAP, direct exposure to NO_2, exposure to ozone, ecosystem effects or visibility impairment.

[b] PM co-benefits are shown as a range from Pope, *et al.* (2002) to Laden, *et al.* (2006). These models assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because the scientific evidence is not yet sufficient to allow differentiation of effects estimates by particle type.

[c] The benefits analysis for the 2010 final rules applied out-dated benefit-per-ton estimates compared to the updated estimates described in this preamble and reflected monetized co-benefits for VOC emissions, which limits direct comparability with the monetized co-benefits estimated for this final rule. In addition, these estimates have been updated from their original currency years to 2010$, so the rounded estimates for the 2010 final rules may not match the original RIAs.

These co-benefits estimates represent the total monetized human health benefits for populations exposed to less $PM_{2.5}$ in 2013 from controls installed to reduce air pollutants in order to meet this final rule. To estimate human health co-benefits of these rules, the EPA used benefit-per-ton factors to quantify the changes in $PM_{2.5}$-related health impacts and monetized benefits based on changes in directly emitted $PM_{2.5}$ and NO_X emissions. These benefit-per-ton factors were derived using the general approach and methodology laid out in Fann, Fulcher and Hubbell (2009).[13] This approach uses a model to convert emissions of $PM_{2.5}$ precursors into changes in ambient $PM_{2.5}$ levels and another model to estimate the changes in human health associated with that change in air quality, which are then divided by the emission reductions to create the benefit-per-ton estimates. However, for these rules, the EPA utilized air quality modeling of emissions in the ''Non-EGU Point other'' category because the EPA does not have modeling specifically for stationary engines.[14] [15] The primary difference between the estimates used in this analysis and the estimates reported in Fann, Fulcher and Hubbell (2009) is the air quality modeling data utilized. While the air quality data used in Fann, Fulcher and Hubbell (2009) reflects broad pollutant/source category combinations, such as all non-EGU stationary point sources, the air quality modeling data used in this analysis has narrower sector categories. In addition, the updated air quality modeling data reflects more recent emissions data (2005 rather than 2001) and has a higher spatial resolution (12 km rather than 36 km grid cells). The benefits methodology, such as health endpoints assessed, risk estimates applied, and valuation techniques applied did not change. As a result, the benefit-per-ton estimates presented herein better reflect the geographic areas and populations likely to be affected by this sector. However, these updated estimates still have similar limitations as all national-average benefit-per-ton estimates in that they reflect the geographic distribution of the modeled emissions, which may not exactly match the emission reductions in this rulemaking, and they may not reflect local variability in population density, meteorology, exposure, baseline health incidence rates or other local factors for any specific location.[16]

[12] Roman, *et al.*, 2008. *Expert Judgment Assessment of the Mortality Impact of Changes in Ambient Fine Particulate Matter in the U.S.*, Environ. Sci. Technol., 42, 7, 2268–2274.

[13] Fann, N., C.M. Fulcher, B.J. Hubbell. 2009. *The influence of location, source, and emission type in estimates of the human health benefits of reducing a ton of air pollution.* Air Qual Atmos Health (2009) 2:169–176.

[14] U.S. Environmental Protection Agency. 2012. *Technical support document: Estimating the benefit per ton of reducing $PM_{2.5}$ precursors from other point sources.* Research Triangle Park, NC.

[15] Stationary engines are included in the other non-EGU point source category. If the affected stationary engines are more rural than the average of the non-EGU sources modeled, then it is possible that the benefits may be somewhat less than the EPA has estimated here. The TSD provides the geographic distribution of the air quality changes associated with this sector. It is important to emphasize that this modeling represents the best available information on the air quality impact on a per ton basis for these sources.

[16] To the extent that the $PM_{2.5}$ improvements achieved by the 2010 final rule would have been located in areas with lower average population density compared to the engines regulated under these amendments, there is a potential for the estimated loss in benefits to be overstated by the use of national-average benefit-per-ton estimates. For example, if only engines in areas with higher population density are regulated, this scenario should result in higher benefit-per-ton estimates than a scenario only regulating engines in areas with lower population density. It is important to

The EPA applies these national benefit-per-ton estimates calculated for this sector separately for directly emitted $PM_{2.5}$ and NO_X and multiply them by the corresponding emission reductions. The sector modeling does not provide estimates of the $PM_{2.5}$-related benefits associated with reducing VOC emissions, but these unquantified benefits are generally small compared to other $PM_{2.5}$ precursors. More information regarding the derivation of the benefit-per-ton estimates for this category is available in the Technical Support Document, which is available in the docket for this rulemaking.

These models assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because the scientific evidence is not yet sufficient to allow differentiation of effects estimates by particle type. The main $PM_{2.5}$ precursors affected by this final rule are directly emitted $PM_{2.5}$ and NO_X. Even though the EPA assumes that all fine particles have equivalent health effects, the benefit-per-ton estimates vary between precursors depending on the location and magnitude of their impact on $PM_{2.5}$ levels, which drive population exposure. For example, directly emitted NO_X has a lower benefit-per-ton estimate than direct $PM_{2.5}$ because it does not form as much $PM_{2.5}$; thus, the exposure would be lower, and the monetized health benefits would be lower.

It is important to note that the magnitude of the $PM_{2.5}$ co-benefits is largely driven by the concentration response function for premature mortality. Experts have advised the EPA to consider a variety of assumptions, including estimates based both on empirical (epidemiological) studies and judgments elicited from scientific experts, to characterize the uncertainty in the relationship between $PM_{2.5}$ concentrations and premature mortality. The EPA cites two key empirical studies, one based on the American Cancer Society cohort study [17] and the extended Six Cities cohort study.[18] In the RIA for the proposed reconsideration amendments rule, which is available in the docket, the EPA also includes benefits estimates derived from the expert judgments and other assumptions.

The EPA strives to use the best available science to support our benefits analyses. The EPA recognizes that interpretation of the science regarding air pollution and health is dynamic and evolving. After reviewing the scientific literature, the EPA has determined that the no-threshold model is the most appropriate model for assessing the mortality benefits associated with reducing $PM_{2.5}$ exposure. Consistent with this finding, the EPA has conformed the previous threshold sensitivity analysis to the current state of the PM science by incorporating a new "Lowest Measured Level" (LML) assessment in the RIA accompanying these rules. While an LML assessment provides some insight into the level of uncertainty in the estimated PM mortality benefits, the EPA does not view the LML as a threshold and continues to quantify PM-related mortality impacts using a full range of modeled air quality concentrations.

Most of the estimated PM-related co-benefits for these rules would accrue to populations exposed to higher levels of $PM_{2.5}$. For this analysis, policy-specific air quality data are not available due to time or resource limitations, and, thus, the EPA is unable to estimate the percentage of premature mortality associated with this specific rule's emission reductions at each $PM_{2.5}$ level. As a surrogate measure of mortality impacts, the EPA provides the percentage of the population exposed at each $PM_{2.5}$ level using the source apportionment modeling used to calculate the benefit-per-ton estimates for this sector. Using the Pope, *et al.* (2002) study, 77 percent of the population is exposed to annual mean $PM_{2.5}$ levels at or above the LML of 7.5 micrograms per cubic meter ($\mu g/m^3$). Using the Laden, *et al.* (2006) study, 25 percent of the population is exposed above the LML of 10 $\mu g/m^3$. It is important to emphasize that we have high confidence in $PM_{2.5}$-related effects down to the lowest LML of the major cohort studies. This fact is important, because, as the EPA models avoided premature deaths among populations exposed to levels of $PM_{2.5}$, the EPA has lower confidence in levels below the LML for each study.

Every benefit analysis examining the potential effects of a change in environmental protection requirements is limited, to some extent, by data gaps, model capabilities (such as geographic coverage) and uncertainties in the underlying scientific and economic studies used to configure the benefit and cost models. Despite these uncertainties, the EPA believes the benefit analysis for these rules provides a reasonable indication of the expected health benefits of the rulemaking under a set of reasonable assumptions. This analysis does not include the type of detailed uncertainty assessment found in the 2006 $PM_{2.5}$ National Ambient Air Quality Standard (NAAQS) RIA because the EPA lacks the necessary air quality input and monitoring data to run the benefits model. In addition, the EPA has not conducted air quality modeling for these rules, and using a benefit-per-ton approach adds another important source of uncertainty to the benefits estimates. The 2006 $PM_{2.5}$ NAAQS benefits analysis [19] provides an indication of the sensitivity of our results to various assumptions.

It should be noted that the monetized co-benefits estimates provided above do not include benefits from several important benefit categories, including exposure to HAP, NO_X, ozone, as well as ecosystem effects and visibility impairment. Although the EPA does not have sufficient information or modeling available to provide monetized estimates for these amendments, the EPA includes a qualitative assessment of these unquantified benefits in the RIAs for these final amendments.

For more information on the benefits analysis, please refer to the CI and SI RIAs for these amendments, which are available in the docket.

D. What are the non-air health, environmental and energy impacts?

The EPA does not anticipate any significant non-air health, environmental or energy impacts as a result of these final amendments.

V. Statutory and Executive Order Reviews

A. Executive Order 12866: Regulatory Planning and Review and Executive Order 13563: Improving Regulation and Regulatory Review

Under section 3(f)(1) of Executive Order 12866 (58 FR 51735, October 4, 1993), this action is an "economically significant regulatory action" because it is likely to have an annual effect on the

note that the benefit-per-ton estimates that EPA applied in this assessment reflect pollution transport as well as a variety of emission source locations, including areas with high and low population density. Without information regarding the specific location of the engines affected by the 2010 final rule and the amendments, it is not possible to be more precise regarding the true magnitude of the loss in benefits.

[17] Pope, *et al.*, 2002. *Lung Cancer, Cardiopulmonary Mortality, and Long-term Exposure to Fine Particulate Air Pollution.* Journal of the American Medical Association 287:1132–1141.

[18] Laden, *et al.*, 2006. *Reduction in Fine Particulate Air Pollution and Mortality.* American Journal of Respiratory and Critical Care Medicine 173: 667–672.

[19] U.S. Environmental Protection Agency, 2006. *Proposed amendments Regulatory Impact Analysis: $PM_{2.5}$ NAAQS.* Prepared by Office of Air and Radiation. October. Available on the Internet at *http://www.epa.gov/ttn/ecas/ria.html.*

economy of $100 million or more. Accordingly, the EPA submitted this action to the Office of Management and Budget (OMB) for review under Executive Order 12866 and Executive Order 13563 (76 FR 3821, January 21, 2011), and any changes made in response to OMB recommendations have been documented in the docket for this action. In addition, the EPA prepared a RIA of the potential costs and benefits associated with this action.

A summary of the monetized benefits, compliance costs and net benefits for the 2010 rule with the final amendments to the stationary CI engines NESHAP at discount rates of 3 percent and 7 percent is in Table 7 of this preamble. The summary for stationary SI engines is included in Table 8 of this preamble. OMB Circular A–4 recommends that analysis of a change in an existing regulatory program use a baseline that assumes ''no change'' in the existing regulation. For purposes of this final rule, however, the EPA has decided that it is appropriate to assume a baseline in which the original 2010 rule did not exist. The EPA feels that this baseline is appropriate because full implementation of this final rule has not taken place as of yet (it will take place in 2013). In addition, this assumption is consistent with the baseline definition applied in the proposed NESHAP for Industrial, Commercial, and Institutional Boilers (76 FR 80532) and NSPS for Commercial/Industrial Solid Waste Incineration Units (76 FR 80452). We have not re-estimated the benefits from the proposal for this final rule because the emission reductions have not changed since the reconsideration proposal. Since the June 7, 2012, reconsideration proposal, we have updated the epidemiology studies used to calculate mortality and morbidity benefits in the PM NAAQS proposal RIA.[20] These updates would reduce the monetized benefits estimated for the RICE NESHAP reconsideration by less than 4 percent.

TABLE 7—SUMMARY OF THE MONETIZED BENEFITS, COMPLIANCE COSTS AND NET BENEFITS FOR THE 2010 RULE WITH THE FINAL AMENDMENTS TO THE STATIONARY CI ENGINE NESHAP IN 2013

[Millions of 2010 dollars][a]

	3-Percent discount rate	7-Percent discount rate
Total Monetized Benefits[b]	$770 to $1,900	$690 to $1,700.
Total Compliance Costs[c]	$373	$373.
Net Benefits	$400 to $1,500	$320 to $1,300.
Non-Monetized Benefits	Health effects from exposure to HAP. Health effects from direct exposure to NO_2 and ozone. Health effects from $PM_{2.5}$ exposure from VOC. Ecosystem effects. Visibility impairment.	

[a] All estimates are for the implementation year (2013) and are rounded to two significant figures.
[b] The total monetized co-benefits reflect the human health benefits associated with reducing exposure to $PM_{2.5}$ through reductions of $PM_{2.5}$ precursors, such as NO_X and directly emitted $PM_{2.5}$. Co-benefits are shown as a range from Pope, *et al.* (2002) to Laden, *et al.* (2006). These models assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because the scientific evidence is not yet sufficient to allow differentiation of effects estimates by particle type.
[c] The engineering compliance costs are annualized using a 7-percent discount rate.

TABLE 8—SUMMARY OF THE MONETIZED BENEFITS, COMPLIANCE COSTS AND NET BENEFITS FOR THE 2010 RULE WITH THE FINAL AMENDMENTS TO THE STATIONARY SI ENGINE NESHAP IN 2013

[Millions of 2010 dollars][a]

	3-Percent discount rate	7-Percent discount rate
Total Monetized Benefits[b]	$62 to $150	$55 to $140.
Total Compliance Costs[c]	$115	$115.
Net Benefits	$ −53 to $35	$ −60 to $25.
Non-Monetized Benefits	Health effects from exposure to HAP. Health effects from direct exposure to NO_2 and ozone. Health effects from $PM_{2.5}$ exposure from VOC. Ecosystem effects. Visibility impairment.	

[a] All estimates are for the implementation year (2013) and are rounded to two significant figures.
[b] The total monetized co-benefits reflect the human health benefits associated with reducing exposure to $PM_{2.5}$ through reductions of $PM_{2.5}$ precursors, such as NO_X and directly emitted $PM_{2.5}$. Co-benefits are shown as a range from Pope, *et al.* (2002) to Laden, *et al.* (2006). These models assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because the scientific evidence is not yet sufficient to allow differentiation of effects estimates by particle type.
[c] The engineering compliance costs are annualized using a 7-percent discount rate.

For more information on the cost-benefit analysis, please refer to the RIA for these final amendments, which is available in the docket for this rulemaking.

[20] U.S. Environmental Protection Agency (U.S. EPA). 2012. Regulatory Impact Analysis for the Proposed Revisions to the National Ambient Air Quality Standards for Particulate Matter. EPA–452/R–12–003. Office of Air Quality Planning and Standards, Health and Environmental Impacts Division. June. Available at *http://www.epa.gov/ttnecas1/regdata/RIAs/PMRIACombinedFile_Bookmarked.pdf.*

B. Paperwork Reduction Act

The information collection requirements in this final rule for stationary SI RICE have been submitted for approval to OMB under the Paperwork Reduction Act, 44 U.S.C. 3501 et seq. The information collection requirements are not enforceable until OMB approves them.

As discussed in this preamble to this final action, there are reporting requirements that will begin in 2016. Owners and operators of emergency stationary engines that operate or are contractually obligated to be available for more than 15 hours per year for emergency demand response must document their operation in annual reports to the EPA. These reports are necessary to enable EPA or States to identify affected facilities that may not be in compliance with the requirements. The burden of this reporting requirement is not included in the ICR burden estimate because it is after the first 3 years after which sources must begin complying with the rule. The reporting burden beginning in 2016 would only be included starting with the first ICR renewal. The EPA anticipates that in most cases, the entity that dispatches the engines to operate, such as the curtailment service provider or utility, will report the information to EPA on behalf of the facility that owns the engine. Thus, the burden of the reporting requirement will likely be on the entities that dispatch the engines. The number of entities is uncertain, but the EPA estimates that approximately 446 local utilities would engage in the reporting requirement. The EPA estimates that each utility would spend approximately 16 hours per year reporting the information to the EPA. As of June 2012, the total compensation for management/professional staff was $51.23 per hour. Adjusting this compensation rate by applying an overhead rate of 167 percent yields a total wage rate of $85.60 per hour.[21] This results in an estimated burden of 7,136 hours at a cost of $611,000 per year, beginning in the year 2015. For curtailment service providers, the EPA estimated the burden of the requirement to be 1,000 hours at a cost of $60,000 in the first year of implementation, 2015, and 250 hours at a cost of $15,000 in subsequent years (using a wage rate of $60 per hour). Using an estimated number of 70 curtailment service providers nationwide that are operating engines for emergency demand response, the burden for curtailment service providers would be 70,000 hours at a cost of $4.2 million in the first year of implementation, 2015, and 17,500 hours at a cost of $1 million in subsequent years. Summing the totals for the cooperatives and curtailment service providers yields a total of 77,136 labor hours at a cost of $4.8 million in the first year that reporting is required, 2015, and 24,636 labor hours at a cost of $1.7 million in subsequent years.

An Agency may not conduct or sponsor, and a person is not required to respond to a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for EPA's regulations in 40 CFR are listed in 40 CFR part 9. When this ICR is approved by OMB, the Agency will publish a technical amendment to 40 CFR part 9 in the **Federal Register** to display the OMB control number for the approved information collection requirements contained in this final rule.

The OMB has previously approved the information collection requirements contained in the 2010 RICE NESHAP final rulemaking, including those for stationary CI RICE, under the provisions of the Paperwork Reduction Act, 44 U.S.C. 3501 et seq. and has assigned OMB control number 2060–0548. The OMB control numbers for the 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 will not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small organizations and small governmental jurisdictions.

For purposes of assessing the impacts of this rule on small entities, small entity is defined as: (1) A small business as defined by the Small Business Administration's (SBA) regulations at 13 CFR 121.201; (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. The SBA defines a small business in terms of the maximum employment, annual sales, or annual energy-generating capacity (for electricity generating units—EGUs) of the owning entity. As mentioned earlier in this preamble, facilities across several industries use affected CI and SI stationary RICE; therefore, a number of size standards are utilized in this analysis.

After considering the economic impacts of this final rule on small entities, I certify that this action will not have a significant economic impact on a substantial number of small entities. The small entities directly regulated by this final rule are those in the 15 industries identified in the 6-digit NAICS code represented in this analysis; the employment size standard (where it applies) varies from 500 to 1,000 employees. The annual sales standard (where it applies) is as low as 0.75 million dollars and as high as 33.5 million dollars. In addition, for the electric power generation industry, which is one of the affected industries, the small business size standard is an ultimate parent entity defined as having a total electric output of 4 million megawatt-hours in the previous fiscal year. We have determined that the percentage of small entities impacted by this final rule having annualized costs of greater than 1 percent of their sales is less than 2 percent of all affected small entities according to the small entity analysis.

Although the final reconsideration rule will not have a significant economic impact on a substantial number of small entities, the EPA nonetheless tried to reduce the impact of this rule on small entities. When developing the revised standards, the EPA took special steps to ensure that the burdens imposed on small entities were minimal. The EPA conducted several meetings with industry trade associations to discuss regulatory options and the corresponding burden on industry, such as recordkeeping and reporting. In addition, as mentioned earlier in this preamble, the EPA is reducing the regulatory requirements for a variety of area sources affected under each of the RICE rules with amendments to the final RICE rules promulgated in 2010.

For more information on the small entity impacts associated with this rulemaking, please refer to the Economic Impact and Small Business Analyses in the public docket. These analyses can be found in the RIA for each of the rules affected by this action.

D. Unfunded Mandates Reform Act

This rule 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 the private sector in any one year. The EPA is finalizing management

[21] *http://www.bls.gov/news.release/ecec.t05.htm.*

practices for certain existing engines located at area sources and is finalizing amendments that will provide owners and operators with alternative and less expensive compliance demonstration methods. As a result of these changes, the EPA anticipates a substantial reduction in the cost burden associated with this rule. Thus, this final rule is not subject to the requirements of sections 202 or 205 of UMRA.

This final 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 changes being finalized in this action by the agency will mostly affect stationary engine owners and operators and will not affect small governments. These final amendments will lead to a reduction in the cost burden.

E. Executive Order 13132: Federalism

This action 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. This action primarily affects private industry, and does not impose significant economic costs on state or local governments. Thus, Executive Order 13132 does not apply to this action. In the spirit of Executive Order 13132, and consistent with the EPA policy to promote communications between the EPA and state and local governments, the EPA specifically solicited comment on the proposed action 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). It will not have substantial direct effects on tribal governments, on the relationship between the federal government and Indian tribes or on the distribution of power and responsibilities between the federal government and Indian tribes, as specified in Executive Order 13175. Thus, Executive Order 13175 does not apply to this action. In the spirit of Executive Order 13175, and consistent with the EPA policy to promote communications between the EPA and tribal governments, the EPA has conducted outreach to tribal governments by providing information on the rule during National Tribal Air Association/EPA Policy Calls.

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

The EPA interprets Executive Order 13045 (62 FR 19885, April 23, 1997) as applying only to those regulatory actions that are based on 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 action 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. This action reduces the burden of the rule on owners and operators of stationary engines by providing less burdensome compliance demonstration methods to owners and operators and greater flexibility in the operation of emergency engines. As a result of these changes, the EPA anticipates a substantial reduction in the cost burden associated with this rule.

I. National Technology Transfer and Advancement Act

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

This rulemaking involves technical standards. The EPA has decided to use EPA Method 25A of 40 CFR part 60, appendix A. While the agency identified two voluntary consensus standards as being potentially applicable, the EPA has decided not to use them in this rulemaking. The two candidate voluntary consensus standards, ISO 14965:2000(E) and EN 12619 (1999), identified would not be practical due to lack of equivalency, documentation, validation data and other important technical and policy considerations. The search and review results have been documented and are placed in the docket for this final rule.

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.

The EPA has concluded that it is not feasible to determine whether there would be disproportionately high and adverse human health or environmental effects on minority, low income or indigenous populations from this final rule, as the EPA does not have specific information about the location of the stationary RICE affected by this final rule. The EPA has taken steps to reduce the impact of the final changes for SI engines by limiting the subcategory for remote engines to those that are not in populated areas.

K. Congressional Review Act

The Congressional Review Act, 5 U.S.C. 801 *et seq.,* as added by the Small Business Regulatory Enforcement Fairness Act of 1996, generally provides that before a rule may take effect, the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of the Congress and to the Comptroller General of the United States. The EPA will submit a report containing this rule and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the United States prior to publication of the rule in the **Federal Register**. A Major rule cannot take effect until 60 days after it is published in the **Federal Register**. This action is a ''major rule'' as defined by 5 U.S.C. 804(2). This rule will be effective on April 1, 2013.

List of Subjects

40 CFR Part 60

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

40 CFR Part 63

Administrative practice and procedure, Air pollution control, Hazardous substances, Incorporation by reference, Intergovernmental relations, Reporting and recordkeeping requirements.

Dated: January 14, 2013.

Lisa P. Jackson,

Administrator.

For the reasons stated in the preamble, title 40, chapter I of the Code of Federal Regulations is 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 adding paragraph (r) to read as follows:

§ 60.17 Incorporations by reference.

* * * * *

(r) The following material is available from the North American Electric Reliability Corporation, 3353 Peachtree Road NE., Suite 600, North Tower, Atlanta, GA 30326, *http://www.nerc.com*, and is available at the following Web site: *http://www.nerc.com/files/EOP-002-3_1.pdf.*

(1) North American Electric Reliability Corporation, Reliability Standards for the Bulk of Electric Systems of North America, Reliability Standard EOP–002–3, Capacity and Energy Emergencies, updated November 19, 2012, IBR approved for §§ 60.4211(f) and 60.4243(d).

(2) [Reserved]

Subpart IIII—[Amended]

■ 3. Section 60.4207 is amended by revising paragraph (b) to read as follows:

§ 60.4207 What fuel requirements must I meet if I am an owner or operator of a stationary CI internal combustion engine subject to this subpart?

* * * * *

(b) Beginning October 1, 2010, owners and operators of stationary CI ICE subject to this subpart with a displacement of less than 30 liters per cylinder that use diesel fuel must use diesel fuel that meets the requirements of 40 CFR 80.510(b) for nonroad diesel fuel, except that any existing diesel fuel purchased (or otherwise obtained) prior to October 1, 2010, may be used until depleted.

* * * * *

■ 4. Section 60.4211 is amended by revising paragraph (f) to read as follows:

§ 60.4211 What are my compliance requirements if I am an owner or operator of a stationary CI internal combustion engine?

* * * * *

(f) If you own or operate an emergency stationary ICE, you must operate the emergency stationary ICE according to the requirements in paragraphs (f)(1) through (3) of this section. In order for the engine to be considered an emergency stationary ICE under this subpart, any operation other than emergency operation, maintenance and testing, emergency demand response, and operation in non-emergency situations for 50 hours per year, as described in paragraphs (f)(1) through (3) of this section, is prohibited. If you do not operate the engine according to the requirements in paragraphs (f)(1) through (3) of this section, the engine will not be considered an emergency engine under this subpart and must meet all requirements for non-emergency engines.

(1) There is no time limit on the use of emergency stationary ICE in emergency situations.

(2) You may operate your emergency stationary ICE for any combination of the purposes specified in paragraphs (f)(2)(i) through (iii) of this section for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by paragraph (f)(3) of this section counts as part of the 100 hours per calendar year allowed by this paragraph (f)(2).

(i) Emergency stationary ICE may be operated for maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that federal, state, or local standards require maintenance and testing of emergency ICE beyond 100 hours per calendar year.

(ii) Emergency stationary ICE may be operated for emergency demand response for periods in which the Reliability Coordinator under the North American Electric Reliability Corporation (NERC) Reliability Standard EOP–002–3, Capacity and Energy Emergencies (incorporated by reference, see § 60.17), or other authorized entity as determined by the Reliability Coordinator, has declared an Energy Emergency Alert Level 2 as defined in the NERC Reliability Standard EOP–002–3.

(iii) Emergency stationary ICE may be operated for periods where there is a deviation of voltage or frequency of 5 percent or greater below standard voltage or frequency.

(3) Emergency stationary ICE may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing and emergency demand response provided in paragraph (f)(2) of this section. Except as provided in paragraph (f)(3)(i) of this section, the 50 hours per calendar year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

(i) The 50 hours per year for non-emergency situations can be used to supply power as part of a financial arrangement with another entity if all of the following conditions are met:

(A) The engine is dispatched by the local balancing authority or local transmission and distribution system operator;

(B) The dispatch is intended to mitigate local transmission and/or distribution limitations so as to avert potential voltage collapse or line overloads that could lead to the interruption of power supply in a local area or region.

(C) The dispatch follows reliability, emergency operation or similar protocols that follow specific NERC, regional, state, public utility commission or local standards or guidelines.

(D) The power is provided only to the facility itself or to support the local transmission and distribution system.

(E) The owner or operator identifies and records the entity that dispatches the engine and the specific NERC, regional, state, public utility commission or local standards or guidelines that are being followed for dispatching the engine. The local balancing authority or local

transmission and distribution system operator may keep these records on behalf of the engine owner or operator.

(ii) [Reserved]

* * * * *

■ 5. Section 60.4214 is amended by adding paragraph (d) to read as follows:

§ 60.4214 What are my notification, reporting, and recordkeeping requirements if I am an owner or operator of a stationary CI internal combustion engine?

* * * * *

(d) If you own or operate an emergency stationary CI ICE with a maximum engine power more than 100 HP that operates or is contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in § 60.4211(f)(2)(ii) and (iii) or that operates for the purposes specified in § 60.4211(f)(3)(i), you must submit an annual report according to the requirements in paragraphs (d)(1) through (3) of this section.

(1) The report must contain the following information:

(i) Company name and address where the engine is located.

(ii) Date of the report and beginning and ending dates of the reporting period.

(iii) Engine site rating and model year.

(iv) Latitude and longitude of the engine in decimal degrees reported to the fifth decimal place.

(v) Hours operated for the purposes specified in § 60.4211(f)(2)(ii) and (iii), including the date, start time, and end time for engine operation for the purposes specified in § 60.4211(f)(2)(ii) and (iii).

(vi) Number of hours the engine is contractually obligated to be available for the purposes specified in § 60.4211(f)(2)(ii) and (iii).

(vii) Hours spent for operation for the purposes specified in § 60.4211(f)(3)(i), including the date, start time, and end time for engine operation for the purposes specified in § 60.4211(f)(3)(i). The report must also identify the entity that dispatched the engine and the situation that necessitated the dispatch of the engine.

(2) The first annual report must cover the calendar year 2015 and must be submitted no later than March 31, 2016. Subsequent annual reports for each calendar year must be submitted no later than March 31 of the following calendar year.

(3) The annual report must be submitted electronically using the subpart specific reporting form in the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (*www.epa.gov/cdx*). However, if the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, the written report must be submitted to the Administrator at the appropriate address listed in § 60.4.

■ 6. Section 60.4219 is amended by revising the definition of "Emergency stationary internal combustion engine" to read as follows:

§ 60.4219 What definitions apply to this subpart?

* * * * *

Emergency stationary internal combustion engine means any stationary reciprocating internal combustion engine that meets all of the criteria in paragraphs (1) through (3) of this definition. All emergency stationary ICE must comply with the requirements specified in § 60.4211(f) in order to be considered emergency stationary ICE. If the engine does not comply with the requirements specified in § 60.4211(f), then it is not considered to be an emergency stationary ICE under this subpart.

(1) The stationary ICE is operated to provide electrical power or mechanical work during an emergency situation. Examples include stationary ICE used to produce power for critical networks or equipment (including power supplied to portions of a facility) when electric power from the local utility (or the normal power source, if the facility runs on its own power production) is interrupted, or stationary ICE used to pump water in the case of fire or flood, etc.

(2) The stationary ICE is operated under limited circumstances for situations not included in paragraph (1) of this definition, as specified in § 60.4211(f).

(3) The stationary ICE operates as part of a financial arrangement with another entity in situations not included in paragraph (1) of this definition only as allowed in § 60.4211(f)(2)(ii) or (iii) and § 60.4211(f)(3)(i).

* * * * *

Subpart JJJJ—[Amended]

■ 7. Section 60.4231 is amended by revising paragraphs (b) through (d) to read as follows:

§ 60.4231 What emission standards must I meet if I am a manufacturer of stationary SI internal combustion engines or equipment containing such engines?

* * * * *

(b) Stationary SI internal combustion engine manufacturers must certify their stationary SI ICE with a maximum engine power greater than 19 KW (25 HP) (except emergency stationary ICE with a maximum engine power greater than 25 HP and less than 130 HP) that use gasoline and that are manufactured on or after the applicable date in § 60.4230(a)(2), or manufactured on or after the applicable date in § 60.4230(a)(4) for emergency stationary ICE with a maximum engine power greater than or equal to 130 HP, to the certification emission standards and other requirements for new nonroad SI engines in 40 CFR part 1048. Stationary SI internal combustion engine manufacturers must certify their emergency stationary SI ICE with a maximum engine power greater than 25 HP and less than 130 HP that use gasoline and that are manufactured on or after the applicable date in § 60.4230(a)(4) to the Phase 1 emission standards in 40 CFR 90.103, applicable to class II engines, and other requirements for new nonroad SI engines in 40 CFR part 90. Stationary SI internal combustion engine manufacturers may certify their stationary SI ICE with a maximum engine power less than or equal to 30 KW (40 HP) with a total displacement less than or equal to 1,000 cubic centimeters (cc) that use gasoline to the certification emission standards and other requirements for new nonroad SI engines in 40 CFR part 90 or 1054, as appropriate.

(c) Stationary SI internal combustion engine manufacturers must certify their stationary SI ICE with a maximum engine power greater than 19 KW (25 HP) (except emergency stationary ICE with a maximum engine power greater than 25 HP and less than 130 HP) that are rich burn engines that use LPG and that are manufactured on or after the applicable date in § 60.4230(a)(2), or manufactured on or after the applicable date in § 60.4230(a)(4) for emergency stationary ICE with a maximum engine power greater than or equal to 130 HP, to the certification emission standards and other requirements for new nonroad SI engines in 40 CFR part 1048. Stationary SI internal combustion engine manufacturers must certify their emergency stationary SI ICE greater than 25 HP and less than 130 HP that are rich burn engines that use LPG and that are manufactured on or after the applicable date in § 60.4230(a)(4) to the Phase 1 emission standards in 40 CFR 90.103, applicable to class II engines, and other requirements for new nonroad SI engines in 40 CFR part 90. Stationary SI internal combustion engine manufacturers may certify their stationary SI ICE with a maximum

engine power less than or equal to 30 KW (40 HP) with a total displacement less than or equal to 1,000 cc that are rich burn engines that use LPG to the certification emission standards and other requirements for new nonroad SI engines in 40 CFR part 90 or 1054, as appropriate.

(d) Stationary SI internal combustion engine manufacturers who choose to certify their stationary SI ICE with a maximum engine power greater than 19 KW (25 HP) and less than 75 KW (100 HP) (except gasoline and rich burn engines that use LPG and emergency stationary ICE with a maximum engine power greater than 25 HP and less than 130 HP) under the voluntary manufacturer certification program described in this subpart must certify those engines to the certification emission standards for new nonroad SI engines in 40 CFR part 1048. Stationary SI internal combustion engine manufacturers who choose to certify their emergency stationary SI ICE greater than 25 HP and less than 130 HP (except gasoline and rich burn engines that use LPG), must certify those engines to the Phase 1 emission standards in 40 CFR 90.103, applicable to class II engines, for new nonroad SI engines in 40 CFR part 90. Stationary SI internal combustion engine manufacturers may certify their stationary SI ICE with a maximum engine power less than or equal to 30 KW (40 HP) with a total displacement less than or equal to 1,000 cc (except gasoline and rich burn engines that use LPG) to the certification emission standards for new nonroad SI engines in 40 CFR part 90 or 1054, as appropriate. For stationary SI ICE with a maximum engine power greater than 19 KW (25 HP) and less than 75 KW (100 HP) (except gasoline and rich burn engines that use LPG and emergency stationary ICE with a maximum engine power greater than 25 HP and less than 130 HP) manufactured prior to January 1, 2011, manufacturers may choose to certify these engines to the standards in Table 1 to this subpart applicable to engines with a maximum engine power greater than or equal to 100 HP and less than 500 HP.

* * * * *

■ 8. Section 60.4243 is amended by revising paragraph (d) to read as follows:

§ 60.4243 What are my compliance requirements if I am an owner or operator of a stationary SI internal combustion engine?

* * * * *

(d) If you own or operate an emergency stationary ICE, you must operate the emergency stationary ICE according to the requirements in paragraphs (d)(1) through (3) of this section. In order for the engine to be considered an emergency stationary ICE under this subpart, any operation other than emergency operation, maintenance and testing, emergency demand response, and operation in non-emergency situations for 50 hours per year, as described in paragraphs (d)(1) through (3) of this section, is prohibited. If you do not operate the engine according to the requirements in paragraphs (d)(1) through (3) of this section, the engine will not be considered an emergency engine under this subpart and must meet all requirements for non-emergency engines.

(1) There is no time limit on the use of emergency stationary ICE in emergency situations.

(2) You may operate your emergency stationary ICE for any combination of the purposes specified in paragraphs (d)(2)(i) through (iii) of this section for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by paragraph (d)(3) of this section counts as part of the 100 hours per calendar year allowed by this paragraph (d)(2).

(i) Emergency stationary ICE may be operated for maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that federal, state, or local standards require maintenance and testing of emergency ICE beyond 100 hours per calendar year.

(ii) Emergency stationary ICE may be operated for emergency demand response for periods in which the Reliability Coordinator under the North American Electric Reliability Corporation (NERC) Reliability Standard EOP–002–3, Capacity and Energy Emergencies (incorporated by reference, see § 60.17), or other authorized entity as determined by the Reliability Coordinator, has declared an Energy Emergency Alert Level 2 as defined in the NERC Reliability Standard EOP–002–3.

(iii) Emergency stationary ICE may be operated for periods where there is a deviation of voltage or frequency of 5 percent or greater below standard voltage or frequency.

(3) Emergency stationary ICE may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing and emergency demand response provided in paragraph (d)(2) of this section. Except as provided in paragraph (d)(3)(i) of this section, the 50 hours per year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

(i) The 50 hours per year for non-emergency situations can be used to supply power as part of a financial arrangement with another entity if all of the following conditions are met:

(A) The engine is dispatched by the local balancing authority or local transmission and distribution system operator;

(B) The dispatch is intended to mitigate local transmission and/or distribution limitations so as to avert potential voltage collapse or line overloads that could lead to the interruption of power supply in a local area or region.

(C) The dispatch follows reliability, emergency operation or similar protocols that follow specific NERC, regional, state, public utility commission or local standards or guidelines.

(D) The power is provided only to the facility itself or to support the local transmission and distribution system.

(E) The owner or operator identifies and records the entity that dispatches the engine and the specific NERC, regional, state, public utility commission or local standards or guidelines that are being followed for dispatching the engine. The local balancing authority or local transmission and distribution system operator may keep these records on behalf of the engine owner or operator.

(ii) [Reserved]

* * * * *

■ 9. Section 60.4245 is amended by adding paragraph (e) to read as follows:

§ 60.4245 What are my notification, reporting, and recordkeeping requirements if I am an owner or operator of a stationary SI internal combustion engine?

* * * * *

(e) If you own or operate an emergency stationary SI ICE with a maximum engine power more than 100 HP that operates or is contractually

obligated to be available for more than 15 hours per calendar year for the purposes specified in § 60.4243(d)(2)(ii) and (iii) or that operates for the purposes specified in § 60.4243(d)(3)(i), you must submit an annual report according to the requirements in paragraphs (e)(1) through (3) of this section.

(1) The report must contain the following information:

(i) Company name and address where the engine is located.

(ii) Date of the report and beginning and ending dates of the reporting period.

(iii) Engine site rating and model year.

(iv) Latitude and longitude of the engine in decimal degrees reported to the fifth decimal place.

(v) Hours operated for the purposes specified in § 60.4243(d)(2)(ii) and (iii), including the date, start time, and end time for engine operation for the purposes specified in § 60.4243(d)(2)(ii) and (iii).

(vi) Number of hours the engine is contractually obligated to be available for the purposes specified in § 60.4243(d)(2)(ii) and (iii).

(vii) Hours spent for operation for the purposes specified in § 60.4243(d)(3)(i), including the date, start time, and end time for engine operation for the purposes specified in § 60.4243(d)(3)(i). The report must also identify the entity that dispatched the engine and the situation that necessitated the dispatch of the engine.

(2) The first annual report must cover the calendar year 2015 and must be submitted no later than March 31, 2016. Subsequent annual reports for each calendar year must be submitted no later than March 31 of the following calendar year.

(3) The annual report must be submitted electronically using the subpart specific reporting form in the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (*www.epa.gov/cdx*). However, if the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, the written report must be submitted to the Administrator at the appropriate address listed in § 60.4.

■ 10. Section 60.4248 is amended by revising the definition of "Emergency stationary internal combustion engine" to read as follows:

§ 60.4248 What definitions apply to this subpart?

* * * * *

Emergency stationary internal combustion engine means any stationary reciprocating internal combustion engine that meets all of the criteria in paragraphs (1) through (3) of this definition. All emergency stationary ICE must comply with the requirements specified in § 60.4243(d) in order to be considered emergency stationary ICE. If the engine does not comply with the requirements specified in § 60.4243(d), then it is not considered to be an emergency stationary ICE under this subpart.

(1) The stationary ICE is operated to provide electrical power or mechanical work during an emergency situation. Examples include stationary ICE used to produce power for critical networks or equipment (including power supplied to portions of a facility) when electric power from the local utility (or the normal power source, if the facility runs on its own power production) is interrupted, or stationary ICE used to pump water in the case of fire or flood, etc.

(2) The stationary ICE is operated under limited circumstances for situations not included in paragraph (1) of this definition, as specified in § 60.4243(d).

(3) The stationary ICE operates as part of a financial arrangement with another entity in situations not included in paragraph (1) of this definition only as allowed in § 60.4243(d)(2)(ii) or (iii) and § 60.4243(d)(3)(i).

* * * * *

■ 11. Table 2 to Subpart JJJJ of part 60 is revised to read as follows:

As stated in § 60.4244, you must comply with the following requirements for performance tests within 10 percent of 100 percent peak (or the highest achievable) load:

TABLE 2 TO SUBPART JJJJ OF PART 60—REQUIREMENTS FOR PERFORMANCE TESTS

For each	Complying with the requirement to	You must	Using	According to the following requirements
1. Stationary SI internal combustion engine demonstrating compliance according to § 60.4244.	a. limit the concentration of NO_X in the stationary SI internal combustion engine exhaust.	i. Select the sampling port location and the number of traverse points;	(1) Method 1 or 1A of 40 CFR part 60, Appendix A or ASTM Method D6522–00 (Reapproved 2005).[a e]	(a) If using a control device, the sampling site must be located at the outlet of the control device.
		ii. Determine the O_2 concentration of the stationary internal combustion engine exhaust at the sampling port location;	(2) Method 3, 3A, or 3B[b] of 40 CFR part 60, appendix A or ASTM Method D6522–00 (Reapproved 2005).[a e]	(b) Measurements to determine O_2 concentration must be made at the same time as the measurements for NO_X concentration.
		iii. If necessary, determine the exhaust flowrate of the stationary internal combustion engine exhaust;	(3) Method 2 or 19 of 40 CFR part 60, appendix A.	
		iv. If necessary, measure moisture content of the stationary internal combustion engine exhaust at the sampling port location; and	(4) Method 4 of 40 CFR part 60, appendix A, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348–03.[e]	(c) Measurements to determine moisture must be made at the same time as the measurementfor NO_X concentration.

TABLE 2 TO SUBPART JJJJ OF PART 60—REQUIREMENTS FOR PERFORMANCE TESTS—Continued

For each	Complying with the requirement to	You must	Using	According to the following requirements
		v. Measure NO_X at the exhaust of the stationary internal combustion engine.	(5) Method 7E of 40 CFR part 60, appendix A, Method D6522–00 (Reapproved 2005)[a e], Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348–03.[e]	(d) Results of this test consist of the average of the three 1-hour or longer runs.
	b. limit the concentration of CO in the stationary SI internal combustion engine exhaust.	i. Select the sampling port location and the number of traverse points;	(1) Method 1 or 1A of 40 CFR part 60, appendix A or ASTM Method D6522–00 (Reapproved 2005).[a e]	(a) If using a control device, the sampling site must be located at the outlet of the control device.
		ii. Determine the O_2 concentration of the stationary internal combustion engine exhaust at the sampling port location;	(2) Method 3, 3A, or 3B[b] of 40 CFR part 60, appendix A or ASTM Method D6522–00 (Reapproved 2005).[a e]	(b) Measurements to determine O_2 concentration must be made at the same time as the measurements for CO concentration.
		iii. If necessary, determine the exhaust flowrate of the stationary internal combustion engine exhaust;	(3) Method 2 or 19 of 40 CFR part 60, appendix A.	
		iv. If necessary, measure moisture content of the stationary internal combustion engine exhaust at the sampling port location; and	(4) Method 4 of 40 CFR part 60, appendix A, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348–03.[e]	(c) Measurements to determine moisture must be made at the same time as the measurement for CO concentration.
		v. Measure CO at the exhaust of the stationary internal combustion engine.	(5) Method 10 of 40 CFR part 60, appendix A, ASTM Method D6522–00 (Reapproved 2005)[a e], Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348–03.[e]	(d) Results of this test consist of the average of the three 1-hour or longer runs.
	c. limit the concentration of VOC in the stationary SI internal combustion engine exhaust	i. Select the sampling port location and the number of traverse points;	(1) Method 1 or 1A of 40 CFR part 60, appendix A.	(a) If using a control device, the sampling site must be located at the outlet of the control device.
		ii. Determine the O_2 concentration of the stationary internal combustion engine exhaust at the sampling port location;	(2) Method 3, 3A, or 3B[b] of 40 CFR part 60, appendix A or ASTM Method D6522–00 (Reapproved 2005).[a e]	(b) Measurements to determine O_2 concentration must be made at the same time as the measurements for VOC concentration.
		iii. If necessary, determine the exhaust flowrate of the stationary internal combustion engine exhaust;	(3) Method 2 or 19 of 40 CFR part 60, appendix A.	
		iv. If necessary, measure moisture content of the stationary internal combustion engine exhaust at the sampling port location; and	(4) Method 4 of 40 CFR part 60, appendix A, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348–03.[e]	(c) Measurements to determine moisture must be made at the same time as the measurementfor VOC concentration.

TABLE 2 TO SUBPART JJJJ OF PART 60—REQUIREMENTS FOR PERFORMANCE TESTS—Continued

For each	Complying with the requirement to	You must	Using	According to the following requirements
		v. Measure VOC at the exhaust of the stationary internal combustion engine.	(5) Methods 25A and 18 of 40 CFR part 60, appendix A, Method 25A with the use of a methane cutter as described in 40 CFR 1065.265, Method 18 of 40 CFR part 60, appendix A,[c d] Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348–03.[e]	(d) Results of this test consist of the average of the three 1-hour or longer runs.

[a] You may petition the Administrator for approval to use alternative methods for portable analyzer.
[b] You may use ASME PTC 19.10–1981, Flue and Exhaust Gas Analyses, for measuring the O_2 content of the exhaust gas as an alternative to EPA Method 3B.
[c] You may use EPA Method 18 of 40 CFR part 60, appendix, provided that you conduct an adequate presurvey test prior to the emissions test, such as the one described in OTM 11 on EPA's Web site (*http://www.epa.gov/ttn/emc/prelim/otm11.pdf*).
[d] You may use ASTM D6420–99 (2004), Test Method for Determination of Gaseous Organic Compounds by Direct Interface Gas Chromatography/Mass Spectrometry as an alternative to EPA Method 18 for measuring total nonmethane organic.
[e] Incorporated by reference, see 40 CFR 60.17.

PART 63—[AMENDED]

■ 12. The authority citation for part 63 continues to read as follows:

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

Subpart A—[Amended]

■ 13. Section 63.14 is amended by:
■ a. Revising paragraphs (b)(28) and (b)(54);
■ b. Adding paragraph (d)(10);
■ c. Revising paragraph (i)(1); and
■ d. Adding paragraph (s) to read as follows:

§ 63.14 Incorporations by reference.

* * * * *

(b) * * *

(28) ASTM D6420–99 (Reapproved 2004), Standard Test Method for Determination of Gaseous Organic Compounds by Direct Interface Gas Chromatography-Mass Spectrometry (Approved October 1, 2004), IBR approved for §§ 60.485(g), 60.485a(g), 63.457(b), 63.772(a) and (e), 63.1282(a) and (d), 63.2351(b), 63.2354(b) and table 8 to subpart HHHHHHH of this part.

* * * * *

(54) ASTM D6348–03, Standard Test Method for Determination of Gaseous Compounds by Extractive Direct Interface Fourier Transform Infrared (FTIR) Spectroscopy, approved 2003, IBR approved for §§ 63.457, 63.1349, table 4 to subpart DDDD of this part, table 4 to subpart ZZZZ of this part, and table 8 to subpart HHHHHHH of this part.

* * * * *

(d) * * *

(10) Alaska Statute, Title 42—Public Utilities And Carriers And Energy Programs, Chapter 45—Rural and Statewide Energy Programs, Article 1, Power Assistance Programs, Sec. 42.45.045. Renewable energy grant fund and recommendation program, effective May 3, 2012, available at *http://www.legis.state.ak.us/basis/folio.asp*, IBR approved for § 63.6675.

* * * * *

(i) * * *

(1) ANSI/ASME PTC 19.10–1981, Flue and Exhaust Gas Analyses [part 10, Instruments and Apparatus], issued August 31, 1981, IBR approved for §§ 63.309(k), 63.457(k), 63.772(e) and (h), 63.865(b), 63.1282(d) and (g), 63.3166(a), 63.3360(e), 63.3545(a), 63.3555(a), 63.4166(a), 63.4362(a), 63.4766(a), 63.4965(a), 63.5160(d), 63.9307(c), 63.9323(a), 63.11148(e), 63.11155(e), 63.11162(f), 63.11163(g), 63.11410(j), 63.11551(a), 63.11646(a), 63.11945, table 5 to subpart DDDDD of this part, table 4 to subpart JJJJJ of this part, table 5 to subpart UUUUU of this part, and table 1 to subpart ZZZZZ of this part.

* * * * *

(s) The following material is available from the North American Electric Reliability Corporation, 3353 Peachtree Road NE., Suite 600, North Tower, Atlanta, GA 30326, *http://www.nerc.com*, and is available at the following Web site: *http://www.nerc.com/files/EOP-002-3_1.pdf*.

(1) North American Electric Reliability Corporation, Reliability Standards for the Bulk of Electric Systems of North America, Reliability Standard EOP–002–3, Capacity and Energy Emergencies, updated November 19, 2012, IBR approved for § 63.6640(f).

(2) [Reserved]

Subpart ZZZZ—[Amended]

■ 14. Section 63.6585 is amended by adding paragraph (f) to read as follows:

§ 63.6585 Am I subject to this subpart?

* * * * *

(f) The emergency stationary RICE listed in paragraphs (f)(1) through (3) of this section are not subject to this subpart. The stationary RICE must meet the definition of an emergency stationary RICE in § 63.6675, which includes operating according to the provisions specified in § 63.6640(f).

(1) Existing residential emergency stationary RICE located at an area source of HAP emissions that do not operate or are not contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in § 63.6640(f)(2)(ii) and (iii) and that do not operate for the purpose specified in § 63.6640(f)(4)(ii).

(2) Existing commercial emergency stationary RICE located at an area source of HAP emissions that do not operate or are not contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in § 63.6640(f)(2)(ii) and (iii) and that do not operate for the purpose specified in § 63.6640(f)(4)(ii).

(3) Existing institutional emergency stationary RICE located at an area source of HAP emissions that do not operate or are not contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in § 63.6640(f)(2)(ii) and (iii) and that do not operate for the purpose specified in § 63.6640(f)(4)(ii).

■ 15. Section 63.6590 is amended by revising paragraphs (b)(1)(i) and (b)(3)(iii) and removing paragraphs (b)(3)(vi) through (viii).

The revisions read as follows.

§ 63.6590 What parts of my plant does this subpart cover?

* * * * *

(b) * * *

(1) * * *

(i) The stationary RICE is a new or reconstructed emergency stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions that does not operate or is not contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in § 63.6640(f)(2)(ii) and (iii).

* * * * *

(3) * * *

(iii) Existing emergency stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions that does not operate or is not contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in § 63.6640(f)(2)(ii) and (iii).

* * * * *

■ 16. Section 63.6595 is amended by revising paragraph (a)(1) to read as follows:

§ 63.6595 When do I have to comply with this subpart?

(a) * * *

(1) If you have an existing stationary RICE, excluding existing non-emergency CI stationary RICE, with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the applicable emission limitations, operating limitations and other requirements no later than June 15, 2007. If you have an existing non-emergency CI stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, an existing stationary CI RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions, or an existing stationary CI RICE located at an area source of HAP emissions, you must comply with the applicable emission limitations, operating limitations, and other requirements no later than May 3, 2013. If you have an existing stationary SI RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions, or an existing stationary SI RICE located at an area source of HAP emissions, you must comply with the applicable emission limitations, operating limitations, and other requirements no later than October 19, 2013.

* * * * *

■ 17. Section 63.6602 is revised to read as follows:

§ 63.6602 What emission limitations and other requirements must I meet if I own or operate an existing stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions?

If you own or operate an existing stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations and other requirements in Table 2c to this subpart which apply to you. Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in § 63.6620 and Table 4 to this subpart.

■ 18. Section 63.6603 is amended by:

■ a. Revising the section heading;

■ b. Revising paragraph (a);

■ c. Revising paragraph (b); and

■ d. Adding paragraphs (c) through (f).

The revisions and addition read as follows:

§ 63.6603 What emission limitations, operating limitations, and other requirements must I meet if I own or operate an existing stationary RICE located at an area source of HAP emissions?

* * * * *

(a) If you own or operate an existing stationary RICE located at an area source of HAP emissions, you must comply with the requirements in Table 2d to this subpart and the operating limitations in Table 2b to this subpart that apply to you.

(b) If you own or operate an existing stationary non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP that meets either paragraph (b)(1) or (2) of this section, you do not have to meet the numerical CO emission limitations specified in Table 2d of this subpart. Existing stationary non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP that meet either paragraph (b)(1) or (2) of this section must meet the management practices that are shown for stationary non-emergency CI RICE with a site rating of less than or equal to 300 HP in Table 2d of this subpart.

(1) The area source is located in an area of Alaska that is not accessible by the Federal Aid Highway System (FAHS).

(2) The stationary RICE is located at an area source that meets paragraphs (b)(2)(i), (ii), and (iii) of this section.

(i) The only connection to the FAHS is through the Alaska Marine Highway System (AMHS), or the stationary RICE operation is within an isolated grid in Alaska that is not connected to the statewide electrical grid referred to as the Alaska Railbelt Grid.

(ii) At least 10 percent of the power generated by the stationary RICE on an annual basis is used for residential purposes.

(iii) The generating capacity of the area source is less than 12 megawatts, or the stationary RICE is used exclusively for backup power for renewable energy.

(c) If you own or operate an existing stationary non-emergency CI RICE with a site rating of more than 300 HP located on an offshore vessel that is an area source of HAP and is a nonroad vehicle that is an Outer Continental Shelf (OCS) source as defined in 40 CFR 55.2, you do not have to meet the numerical CO emission limitations specified in Table 2d of this subpart. You must meet all of the following management practices:

(1) Change oil every 1,000 hours of operation or annually, whichever comes first. Sources have the option to utilize an oil analysis program as described in § 63.6625(i) in order to extend the specified oil change requirement.

(2) Inspect and clean air filters every 750 hours of operation or annually, whichever comes first, and replace as necessary.

(3) Inspect fuel filters and belts, if installed, every 750 hours of operation or annually, whichever comes first, and replace as necessary.

(4) Inspect all flexible hoses every 1,000 hours of operation or annually, whichever comes first, and replace as necessary.

(d) If you own or operate an existing non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP emissions that is certified to the Tier 1 or Tier 2 emission standards in Table 1 of 40 CFR 89.112 and that is subject to an enforceable state or local standard that requires the engine to be replaced no later than June 1, 2018, you may until January 1, 2015, or 12 years after the installation date of the engine (whichever is later), but not later than June 1, 2018, choose to comply with the management practices that are shown for stationary non-emergency CI RICE with a site rating of less than or equal to 300 HP in Table 2d of this subpart instead of the applicable emission limitations in Table 2d, operating limitations in Table 2b, and crankcase ventilation system requirements in § 63.6625(g). You must comply with the emission limitations in Table 2d and operating limitations in Table 2b that apply for non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP emissions by January 1, 2015, or 12 years after the installation date of the

engine (whichever is later), but not later than June 1, 2018. You must also comply with the crankcase ventilation system requirements in § 63.6625(g) by January 1, 2015, or 12 years after the installation date of the engine (whichever is later), but not later than June 1, 2018.

(e) If you own or operate an existing non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP emissions that is certified to the Tier 3 (Tier 2 for engines above 560 kilowatt (kW)) emission standards in Table 1 of 40 CFR 89.112, you may comply with the requirements under this part by meeting the requirements for Tier 3 engines (Tier 2 for engines above 560 kW) in 40 CFR part 60 subpart IIII instead of the emission limitations and other requirements that would otherwise apply under this part for existing non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP emissions.

(f) An existing non-emergency SI 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at area sources of HAP must meet the definition of remote stationary RICE in § 63.6675 on the initial compliance date for the engine, October 19, 2013, in order to be considered a remote stationary RICE under this subpart. Owners and operators of existing non-emergency SI 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at area sources of HAP that meet the definition of remote stationary RICE in § 63.6675 of this subpart as of October 19, 2013 must evaluate the status of their stationary RICE every 12 months. Owners and operators must keep records of the initial and annual evaluation of the status of the engine. If the evaluation indicates that the stationary RICE no longer meets the definition of remote stationary RICE in § 63.6675 of this subpart, the owner or operator must comply with all of the requirements for existing non-emergency SI 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at area sources of HAP that are not remote stationary RICE within 1 year of the evaluation.

■ 19. Section 63.6604 is revised to read as follows:

§ 63.6604 What fuel requirements must I meet if I own or operate a stationary CI RICE?

(a) If you own or operate an existing non-emergency, non-black start CI stationary RICE with a site rating of more than 300 brake HP with a displacement of less than 30 liters per cylinder that uses diesel fuel, you must use diesel fuel that meets the requirements in 40 CFR 80.510(b) for nonroad diesel fuel.

(b) Beginning January 1, 2015, if you own or operate an existing emergency CI stationary RICE with a site rating of more than 100 brake HP and a displacement of less than 30 liters per cylinder that uses diesel fuel and operates or is contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in § 63.6640(f)(2)(ii) and (iii) or that operates for the purpose specified in § 63.6640(f)(4)(ii), you must use diesel fuel that meets the requirements in 40 CFR 80.510(b) for nonroad diesel fuel, except that any existing diesel fuel purchased (or otherwise obtained) prior to January 1, 2015, may be used until depleted.

(c) Beginning January 1, 2015, if you own or operate a new emergency CI stationary RICE with a site rating of more than 500 brake HP and a displacement of less than 30 liters per cylinder located at a major source of HAP that uses diesel fuel and operates or is contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in § 63.6640(f)(2)(ii) and (iii), you must use diesel fuel that meets the requirements in 40 CFR 80.510(b) for nonroad diesel fuel, except that any existing diesel fuel purchased (or otherwise obtained) prior to January 1, 2015, may be used until depleted.

(d) Existing CI stationary RICE located in Guam, American Samoa, the Commonwealth of the Northern Mariana Islands, at area sources in areas of Alaska that meet either § 63.6603(b)(1) or § 63.6603(b)(2), or are on offshore vessels that meet § 63.6603(c) are exempt from the requirements of this section.

■ 20. Section 63.6605 is amended by revising paragraph (a) to read as follows:

§ 63.6605 What are my general requirements for complying with this subpart?

(a) You must be in compliance with the emission limitations, operating limitations, and other requirements in this subpart that apply to you at all times.

* * * * *

■ 21. Section 63.6620 is amended by revising paragraphs (b), (d) and (e) to read as follows:

§ 63.6620 What performance tests and other procedures must I use?

* * * * *

(b) Each performance test must be conducted according to the requirements that this subpart specifies in Table 4 to this subpart. If you own or operate a non-operational stationary RICE that is subject to performance testing, you do not need to start up the engine solely to conduct the performance test. Owners and operators of a non-operational engine can conduct the performance test when the engine is started up again. The test must be conducted at any load condition within plus or minus 10 percent of 100 percent load for the stationary RICE listed in paragraphs (b)(1) through (4) of this section.

(1) Non-emergency 4SRB stationary RICE with a site rating of greater than 500 brake HP located at a major source of HAP emissions.

(2) New non-emergency 4SLB stationary RICE with a site rating of greater than or equal to 250 brake HP located at a major source of HAP emissions.

(3) New non-emergency 2SLB stationary RICE with a site rating of greater than 500 brake HP located at a major source of HAP emissions.

(4) New non-emergency CI stationary RICE with a site rating of greater than 500 brake HP located at a major source of HAP emissions.

* * * * *

(d) You must conduct three separate test runs for each performance test required in this section, as specified in § 63.7(e)(3). Each test run must last at least 1 hour, unless otherwise specified in this subpart.

(e)(1) You must use Equation 1 of this section to determine

$$\frac{C_i - C_o}{C_i} \times 100 = R \quad (Eq.\ 1)$$

compliance with the percent reduction requirement:

Where:

C_i = concentration of carbon monoxide (CO), total hydrocarbons (THC), or formaldehyde at the control device inlet,

C_o = concentration of CO, THC, or formaldehyde at the control device outlet, and

R = percent reduction of CO, THC, or formaldehyde emissions.

(2) You must normalize the CO, THC, or formaldehyde concentrations at the inlet and outlet of the control device to a dry basis and to 15 percent oxygen, or an equivalent percent carbon dioxide (CO_2). If pollutant concentrations are to be corrected to 15 percent oxygen and CO_2 concentration is measured in lieu of oxygen concentration measurement, a CO_2 correction factor is needed. Calculate the CO_2 correction factor as described in paragraphs (e)(2)(i) through (iii) of this section.

(i) Calculate the fuel-specific F_o value for the fuel burned during the test using values obtained from Method 19, Section 5.2, and the following equation:

$$F_O = \frac{0.209\ F_d}{F_C} \quad (Eq.\ 2)$$

Where:

F_o = Fuel factor based on the ratio of oxygen volume to the ultimate CO_2 volume produced by the fuel at zero percent excess air.

0.209 = Fraction of air that is oxygen, percent/100.

F_d = Ratio of the volume of dry effluent gas to the gross calorific value of the fuel from Method 19, dsm^3/J ($dscf/10^6$ Btu).

F_c = Ratio of the volume of CO_2 produced to the gross calorific value of the fuel from Method 19, dsm^3/J ($dscf/10^6$ Btu)

(ii) Calculate the CO_2 correction factor for correcting

$$X_{CO2} = \frac{5.9}{F_O} \quad (Eq.\ 3)$$

measurement data to 15 percent O_2, as follows:

Where:

X_{CO2} = CO_2 correction factor, percent.

5.9 = 20.9 percent O_2—15 percent O_2, the defined O_2 correction value, percent.

(iii) Calculate the CO, THC, and formaldehyde gas concentrations adjusted to 15 percent O_2 using CO_2 as follows:

$$C_{adj} = C_d \frac{X_{CO2}}{\%CO_2} \quad (Eq.\ 4)$$

Where:

C_{adj} = Calculated concentration of CO, THC, or formaldehyde adjusted to 15 percent O_2.

C_d = Measured concentration of CO, THC, or formaldehyde, uncorrected.

X_{CO2} = CO_2 correction factor, percent.

$\%CO_2$ = Measured CO_2 concentration measured, dry basis, percent.

* * * * *

■ 22. Section 63.6625 is amended by:

■ a. Revising paragraph (a) introductory text;

■ b. Revising the first sentence in paragraph (b) introductory text;

■ c. Revising paragraph (b)(1)(iv);

■ d. Revising paragraph (e)(6),

■ e. Revising paragraph (g),

■ f. Revising paragraph (i); and

■ g. Revising paragraph (j).

The revisions read as follows:

§ 63.6625 What are my monitoring, installation, collection, operation, and maintenance requirements?

(a) If you elect to install a CEMS as specified in Table 5 of this subpart, you must install, operate, and maintain a CEMS to monitor CO and either O_2 or CO_2 according to the requirements in paragraphs (a)(1) through (4) of this section. If you are meeting a requirement to reduce CO emissions, the CEMS must be installed at both the inlet and outlet of the control device. If you are meeting a requirement to limit the concentration of CO, the CEMS must be installed at the outlet of the control device.

* * * * *

(b) If you are required to install a continuous parameter monitoring system (CPMS) as specified in Table 5 of this subpart, you must install, operate, and maintain each CPMS according to the requirements in paragraphs (b)(1) through (6) of this section. * * *

(1) * * *

(iv) Ongoing operation and maintenance procedures in accordance with provisions in § 63.8(c)(1)(ii) and (c)(3); and

* * * * *

(e) * * *

(6) An existing non-emergency, non-black start stationary RICE located at an area source of HAP emissions which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis.

* * * * *

(g) If you own or operate an existing non-emergency, non-black start CI engine greater than or equal to 300 HP that is not equipped with a closed crankcase ventilation system, you must comply with either paragraph (g)(1) or paragraph (2) of this section. Owners and operators must follow the manufacturer's specified maintenance requirements for operating and maintaining the open or closed crankcase ventilation systems and replacing the crankcase filters, or can request the Administrator to approve different maintenance requirements that are as protective as manufacturer requirements. Existing CI engines located at area sources in areas of Alaska that meet either § 63.6603(b)(1) or § 63.6603(b)(2) do not have to meet the requirements of this paragraph (g). Existing CI engines located on offshore vessels that meet § 63.6603(c) do not have to meet the requirements of this paragraph (g).

(1) Install a closed crankcase ventilation system that prevents crankcase emissions from being emitted to the atmosphere, or

(2) Install an open crankcase filtration emission control system that reduces emissions from the crankcase by filtering the exhaust stream to remove oil mist, particulates and metals.

* * * * *

(i) If you own or operate a stationary CI engine that is subject to the work, operation or management practices in items 1 or 2 of Table 2c to this subpart or in items 1 or 4 of Table 2d to this subpart, you have the option of utilizing an oil analysis program in order to extend the specified oil change requirement in Tables 2c and 2d to this subpart. The oil analysis must be performed at the same frequency specified for changing the oil in Table 2c or 2d to this subpart. The analysis program must at a minimum analyze the following three parameters: Total Base Number, viscosity, and percent water content. The condemning limits for these parameters are as follows: Total Base Number is less than 30 percent of the Total Base Number of the oil when new; viscosity of the oil has changed by more than 20 percent from the viscosity of the oil when new; or percent water content (by volume) is greater than 0.5. If all of these condemning limits are not exceeded, the engine owner or operator is not required to change the oil. If any of the limits are exceeded, the engine owner or operator must change the oil within 2 business days of receiving the results of the analysis; if the engine is not in operation when the results of the analysis are received, the engine owner or operator must change the oil within 2 business days or before commencing operation, whichever is later. The owner or operator must keep records of the parameters that are analyzed as part of the program, the results of the analysis, and the oil changes for the engine. The analysis program must be part of the maintenance plan for the engine.

(j) If you own or operate a stationary SI engine that is subject to the work, operation or management practices in items 6, 7, or 8 of Table 2c to this subpart or in items 5, 6, 7, 9, or 11 of Table 2d to this subpart, you have the option of utilizing an oil analysis program in order to extend the specified oil change requirement in Tables 2c and 2d to this subpart. The oil analysis must be performed at the same frequency specified for changing the oil in Table 2c or 2d to this subpart. The analysis program must at a minimum analyze the following three parameters: Total Acid Number, viscosity, and percent water content. The condemning limits for these parameters are as follows: Total Acid Number increases by more than 3.0 milligrams of potassium hydroxide (KOH) per gram from Total Acid Number of the oil when new; viscosity of the oil has changed by more than 20

percent from the viscosity of the oil when new; or percent water content (by volume) is greater than 0.5. If all of these condemning limits are not exceeded, the engine owner or operator is not required to change the oil. If any of the limits are exceeded, the engine owner or operator must change the oil within 2 business days of receiving the results of the analysis; if the engine is not in operation when the results of the analysis are received, the engine owner or operator must change the oil within 2 business days or before commencing operation, whichever is later. The owner or operator must keep records of the parameters that are analyzed as part of the program, the results of the analysis, and the oil changes for the engine. The analysis program must be part of the maintenance plan for the engine.

■ 23. Section 63.6630 is amended by revising the section heading and paragraph (a) and adding paragraphs (d) and (e) to read as follows:

§ 63.6630 How do I demonstrate initial compliance with the emission limitations, operating limitations, and other requirements?

(a) You must demonstrate initial compliance with each emission limitation, operating limitation, and other requirement that applies to you according to Table 5 of this subpart.

* * * * *

(d) Non-emergency 4SRB stationary RICE complying with the requirement to reduce formaldehyde emissions by 76 percent or more can demonstrate initial compliance with the formaldehyde emission limit by testing for THC instead of formaldehyde. The testing must be conducted according to the requirements in Table 4 of this subpart. The average reduction of emissions of THC determined from the performance test must be equal to or greater than 30 percent.

(e) The initial compliance demonstration required for existing non-emergency 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year must be conducted according to the following requirements:

(1) The compliance demonstration must consist of at least three test runs.

(2) Each test run must be of at least 15 minute duration, except that each test conducted using the method in appendix A to this subpart must consist of at least one measurement cycle and include at least 2 minutes of test data phase measurement.

(3) If you are demonstrating compliance with the CO concentration or CO percent reduction requirement, you must measure CO emissions using one of the CO measurement methods specified in Table 4 of this subpart, or using appendix A to this subpart.

(4) If you are demonstrating compliance with the THC percent reduction requirement, you must measure THC emissions using Method 25A, reported as propane, of 40 CFR part 60, appendix A.

(5) You must measure O_2 using one of the O_2 measurement methods specified in Table 4 of this subpart. Measurements to determine O_2 concentration must be made at the same time as the measurements for CO or THC concentration.

(6) If you are demonstrating compliance with the CO or THC percent reduction requirement, you must measure CO or THC emissions and O_2 emissions simultaneously at the inlet and outlet of the control device.

■ 24. Section 63.6640 is amended by:

■ a. Revising the section heading;

■ b. Revising paragraph (a);

■ c. Adding paragraph (c); and

■ d. Revising paragraph (f).

The revisions and addition read as follows:

§ 63.6640 How do I demonstrate continuous compliance with the emission limitations, operating limitations, and other requirements?

(a) You must demonstrate continuous compliance with each emission limitation, operating limitation, and other requirements in Tables 1a and 1b, Tables 2a and 2b, Table 2c, and Table 2d to this subpart that apply to you according to methods specified in Table 6 to this subpart.

* * * * *

(c) The annual compliance demonstration required for existing non-emergency 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year must be conducted according to the following requirements:

(1) The compliance demonstration must consist of at least one test run.

(2) Each test run must be of at least 15 minute duration, except that each test conducted using the method in appendix A to this subpart must consist of at least one measurement cycle and include at least 2 minutes of test data phase measurement.

(3) If you are demonstrating compliance with the CO concentration or CO percent reduction requirement, you must measure CO emissions using one of the CO measurement methods specified in Table 4 of this subpart, or using appendix A to this subpart.

(4) If you are demonstrating compliance with the THC percent reduction requirement, you must measure THC emissions using Method 25A, reported as propane, of 40 CFR part 60, appendix A.

(5) You must measure O_2 using one of the O_2 measurement methods specified in Table 4 of this subpart. Measurements to determine O_2 concentration must be made at the same time as the measurements for CO or THC concentration.

(6) If you are demonstrating compliance with the CO or THC percent reduction requirement, you must measure CO or THC emissions and O_2 emissions simultaneously at the inlet and outlet of the control device.

(7) If the results of the annual compliance demonstration show that the emissions exceed the levels specified in Table 6 of this subpart, the stationary RICE must be shut down as soon as safely possible, and appropriate corrective action must be taken (e.g., repairs, catalyst cleaning, catalyst replacement). The stationary RICE must be retested within 7 days of being restarted and the emissions must meet the levels specified in Table 6 of this subpart. If the retest shows that the emissions continue to exceed the specified levels, the stationary RICE must again be shut down as soon as safely possible, and the stationary RICE may not operate, except for purposes of startup and testing, until the owner/operator demonstrates through testing that the emissions do not exceed the levels specified in Table 6 of this subpart.

* * * * *

(f) If you own or operate an emergency stationary RICE, you must operate the emergency stationary RICE according to the requirements in paragraphs (f)(1) through (4) of this section. In order for the engine to be considered an emergency stationary RICE under this subpart, any operation other than emergency operation, maintenance and testing, emergency demand response, and operation in non-emergency situations for 50 hours per year, as described in paragraphs (f)(1) through (4) of this section, is prohibited. If you do not operate the engine according to the requirements in paragraphs (f)(1) through (4) of this section, the engine will not be considered an emergency engine under this subpart and must meet all requirements for non-emergency engines.

(1) There is no time limit on the use of emergency stationary RICE in emergency situations.

(2) You may operate your emergency stationary RICE for any combination of the purposes specified in paragraphs (f)(2)(i) through (iii) of this section for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by paragraphs (f)(3) and (4) of this section counts as part of the 100 hours per calendar year allowed by this paragraph (f)(2).

(i) Emergency stationary RICE may be operated for maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that federal, state, or local standards require maintenance and testing of emergency RICE beyond 100 hours per calendar year.

(ii) Emergency stationary RICE may be operated for emergency demand response for periods in which the Reliability Coordinator under the North American Electric Reliability Corporation (NERC) Reliability Standard EOP–002–3, Capacity and Energy Emergencies (incorporated by reference, see § 63.14), or other authorized entity as determined by the Reliability Coordinator, has declared an Energy Emergency Alert Level 2 as defined in the NERC Reliability Standard EOP–002–3.

(iii) Emergency stationary RICE may be operated for periods where there is a deviation of voltage or frequency of 5 percent or greater below standard voltage or frequency.

(3) Emergency stationary RICE located at major sources of HAP may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing and emergency demand response provided in paragraph (f)(2) of this section. The 50 hours per year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to supply power to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

(4) Emergency stationary RICE located at area sources of HAP may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing and emergency demand response provided in paragraph (f)(2) of this section. Except as provided in paragraphs (f)(4)(i) and (ii) of this section, the 50 hours per year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

(i) Prior to May 3, 2014, the 50 hours per year for non-emergency situations can be used for peak shaving or non-emergency demand response to generate income for a facility, or to otherwise supply power as part of a financial arrangement with another entity if the engine is operated as part of a peak shaving (load management program) with the local distribution system operator and the power is provided only to the facility itself or to support the local distribution system.

(ii) The 50 hours per year for non-emergency situations can be used to supply power as part of a financial arrangement with another entity if all of the following conditions are met:

(A) The engine is dispatched by the local balancing authority or local transmission and distribution system operator.

(B) The dispatch is intended to mitigate local transmission and/or distribution limitations so as to avert potential voltage collapse or line overloads that could lead to the interruption of power supply in a local area or region.

(C) The dispatch follows reliability, emergency operation or similar protocols that follow specific NERC, regional, state, public utility commission or local standards or guidelines.

(D) The power is provided only to the facility itself or to support the local transmission and distribution system.

(E) The owner or operator identifies and records the entity that dispatches the engine and the specific NERC, regional, state, public utility commission or local standards or guidelines that are being followed for dispatching the engine. The local balancing authority or local transmission and distribution system operator may keep these records on behalf of the engine owner or operator.

■ 25. Section 63.6645 is amended by adding paragraph (i) to read as follows:

§ 63.6645 What notifications must I submit and when?

* * * * *

(i) If you own or operate an existing non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP emissions that is certified to the Tier 1 or Tier 2 emission standards in Table 1 of 40 CFR 89.112 and subject to an enforceable state or local standard requiring engine replacement and you intend to meet management practices rather than emission limits, as specified in § 63.6603(d), you must submit a notification by March 3, 2013, stating that you intend to use the provision in § 63.6603(d) and identifying the state or local regulation that the engine is subject to.

■ 26. Section 63.6650 is amended by adding paragraph (h) to read as follows:

§ 63.6650 What reports must I submit and when?

* * * * *

(h) If you own or operate an emergency stationary RICE with a site rating of more than 100 brake HP that operates or is contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in § 63.6640(f)(2)(ii) and (iii) or that operates for the purpose specified in § 63.6640(f)(4)(ii), you must submit an annual report according to the requirements in paragraphs (h)(1) through (3) of this section.

(1) The report must contain the following information:

(i) Company name and address where the engine is located.

(ii) Date of the report and beginning and ending dates of the reporting period.

(iii) Engine site rating and model year.

(iv) Latitude and longitude of the engine in decimal degrees reported to the fifth decimal place.

(v) Hours operated for the purposes specified in § 63.6640(f)(2)(ii) and (iii), including the date, start time, and end time for engine operation for the purposes specified in § 63.6640(f)(2)(ii) and (iii).

(vi) Number of hours the engine is contractually obligated to be available for the purposes specified in § 63.6640(f)(2)(ii) and (iii).

(vii) Hours spent for operation for the purpose specified in § 63.6640(f)(4)(ii), including the date, start time, and end time for engine operation for the purposes specified in § 63.6640(f)(4)(ii). The report must also identify the entity that dispatched the engine and the situation that necessitated the dispatch of the engine.

(viii) If there were no deviations from the fuel requirements in § 63.6604 that apply to the engine (if any), a statement that there were no deviations from the fuel requirements during the reporting period.

(ix) If there were deviations from the fuel requirements in § 63.6604 that apply to the engine (if any), information on the number, duration, and cause of deviations, and the corrective action taken.

(2) The first annual report must cover the calendar year 2015 and must be submitted no later than March 31, 2016. Subsequent annual reports for each calendar year must be submitted no later than March 31 of the following calendar year.

(3) The annual report must be submitted electronically using the subpart specific reporting form in the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (*www.epa.gov/cdx*). However, if the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, the written report must be submitted to the Administrator at the appropriate address listed in § 63.13.

■ 27. Section 63.6655 is amended by revising paragraph (f) introductory text to read as follows:

§ 63.6655 What records must I keep?

* * * * *

(f) If you own or operate any of the stationary RICE in paragraphs (f)(1) through (2) of this section, you must keep records of the hours of operation of the engine that is recorded through the non-resettable hour meter. The owner or operator must document how many hours are spent for emergency operation, including what classified the operation as emergency and how many hours are spent for non-emergency operation. If the engine is used for the purposes specified in § 63.6640(f)(2)(ii) or (iii) or § 63.6640(f)(4)(ii), the owner or operator must keep records of the notification of the emergency situation, and the date, start time, and end time of engine operation for these purposes.

* * * * *

■ 28. Section 63.6675 is amended by:

■ a. Adding in alphabetical order the definition of *Alaska Railbelt Grid;*

■ b. Adding in alphabetical order the definition of *Backup power for renewable energy;*

■ c. Revising the definition of *Emergency stationary RICE;* and

■ d. Adding in alphabetical order the definition of *Remote stationary RICE.*

The additions and revision read as follows.

§ 63.6675 What definitions apply to this subpart?

* * * * *

Alaska Railbelt Grid means the service areas of the six regulated public utilities that extend from Fairbanks to Anchorage and the Kenai Peninsula. These utilities are Golden Valley Electric Association; Chugach Electric Association; Matanuska Electric Association; Homer Electric Association; Anchorage Municipal Light & Power; and the City of Seward Electric System.

* * * * *

Backup power for renewable energy means an engine that provides backup power to a facility that generates electricity from renewable energy resources, as that term is defined in Alaska Statute 42.45.045(l)(5) (incorporated by reference, see § 63.14).

* * * * *

Emergency stationary RICE means any stationary reciprocating internal combustion engine that meets all of the criteria in paragraphs (1) through (3) of this definition. All emergency stationary RICE must comply with the requirements specified in § 63.6640(f) in order to be considered emergency stationary RICE. If the engine does not comply with the requirements specified in § 63.6640(f), then it is not considered to be an emergency stationary RICE under this subpart.

(1) The stationary RICE is operated to provide electrical power or mechanical work during an emergency situation. Examples include stationary RICE used to produce power for critical networks or equipment (including power supplied to portions of a facility) when electric power from the local utility (or the normal power source, if the facility runs on its own power production) is interrupted, or stationary RICE used to pump water in the case of fire or flood, etc.

(2) The stationary RICE is operated under limited circumstances for situations not included in paragraph (1) of this definition, as specified in § 63.6640(f).

(3) The stationary RICE operates as part of a financial arrangement with another entity in situations not included in paragraph (1) of this definition only as allowed in § 63.6640(f)(2)(ii) or (iii) and § 63.6640(f)(4)(i) or (ii).

* * * * *

Remote stationary RICE means stationary RICE meeting any of the following criteria:

(1) Stationary RICE located in an offshore area that is beyond the line of ordinary low water along that portion of the coast of the United States that is in direct contact with the open seas and beyond the line marking the seaward limit of inland waters.

(2) Stationary RICE located on a pipeline segment that meets both of the criteria in paragraphs (2)(i) and (ii) of this definition.

(i) A pipeline segment with 10 or fewer buildings intended for human occupancy and no buildings with four or more stories within 220 yards (200 meters) on either side of the centerline of any continuous 1-mile (1.6 kilometers) length of pipeline. Each separate dwelling unit in a multiple dwelling unit building is counted as a separate building intended for human occupancy.

(ii) The pipeline segment does not lie within 100 yards (91 meters) of either a building or a small, well-defined outside area (such as a playground, recreation area, outdoor theater, or other place of public assembly) that is occupied by 20 or more persons on at least 5 days a week for 10 weeks in any 12-month period. The days and weeks need not be consecutive. The building or area is considered occupied for a full day if it is occupied for any portion of the day.

(iii) For purposes of this paragraph (2), the term pipeline segment means all parts of those physical facilities through which gas moves in transportation, including but not limited to pipe, valves, and other appurtenance attached to pipe, compressor units, metering stations, regulator stations, delivery stations, holders, and fabricated assemblies. Stationary RICE located within 50 yards (46 meters) of the pipeline segment providing power for equipment on a pipeline segment are part of the pipeline segment. Transportation of gas means the gathering, transmission, or distribution of gas by pipeline, or the storage of gas. A building is intended for human occupancy if its primary use is for a purpose involving the presence of humans.

(3) Stationary RICE that are not located on gas pipelines and that have 5 or fewer buildings intended for human occupancy and no buildings with four or more stories within a 0.25 mile radius around the engine. A building is intended for human occupancy if its primary use is for a purpose involving the presence of humans.

* * * * *

■ 29. Table 1b to Subpart ZZZZ of Part 63 is revised to read as follows:

As stated in §§ 63.6600, 63.6603, 63.6630 and 63.6640, you must comply with the following operating limitations for existing, new and reconstructed

4SRB stationary RICE >500 HP located at a major source of HAP emissions:

TABLE 1b TO SUBPART ZZZZ OF PART 63—OPERATING LIMITATIONS FOR EXISTING, NEW, AND RECONSTRUCTED SI 4SRB STATIONARY RICE >500 HP LOCATED AT A MAJOR SOURCE OF HAP EMISSIONS

For each . . .	You must meet the following operating limitation, except during periods of startup . . .
1. existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions complying with the requirement to reduce formaldehyde emissions by 76 percent or more (or by 75 percent or more, if applicable) and using NSCR; or existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust to 350 ppbvd or less at 15 percent O_2 and using NSCR;	a. maintain your catalyst so that the pressure drop across the catalyst does not change by more than 2 inches of water at 100 percent load plus or minus 10 percent from the pressure drop across the catalyst measured during the initial performance test; and b. maintain the temperature of your stationary RICE exhaust so that the catalyst inlet temperature is greater than or equal to 750 °F and less than or equal to 1250 °F.[1]
2. existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions complying with the requirement to reduce formaldehyde emissions by 76 percent or more (or by 75 percent or more, if applicable) and not using NSCR; or existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust to 350 ppbvd or less at 15 percent O_2 and not using NSCR.	Comply with any operating limitations approved by the Administrator.

[1] Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.8(f) for a different temperature range.

■ 30. Table 2b to Subpart ZZZZ of Part 63 is revised to read as follows:

As stated in §§ 63.6600, 63.6601, 63.6603, 63.6630, and 63.6640, you must comply with the following operating limitations for new and reconstructed 2SLB and CI stationary RICE >500 HP located at a major source of HAP emissions; new and reconstructed 4SLB stationary RICE ≥250 HP located at a major source of HAP emissions; and existing CI stationary RICE >500 HP:

TABLE 2b TO SUBPART ZZZZ OF PART 63—OPERATING LIMITATIONS FOR NEW AND RECONSTRUCTED 2SLB AND CI STATIONARY RICE >500 HP LOCATED AT A MAJOR SOURCE OF HAP EMISSIONS, NEW AND RECONSTRUCTED 4SLB STATIONARY RICE ≥250 HP LOCATED AT A MAJOR SOURCE OF HAP EMISSIONS, EXISTING CI STATIONARY RICE >500 HP

For each . . .	You must meet the following operating limitation, except during periods of startup . . .
1. New and reconstructed 2SLB and CI stationary RICE >500 HP located at a major source of HAP emissions and new and reconstructed 4SLB stationary RICE ≥250 HP located at a major source of HAP emissions complying with the requirement to reduce CO emissions and using an oxidation catalyst; and New and reconstructed 2SLB and CI stationary RICE >500 HP located at a major source of HAP emissions and new and reconstructed 4SLB stationary RICE ≥250 HP located at a major source of HAP emissions complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust and using an oxidation catalyst.	a. maintain your catalyst so that the pressure drop across the catalyst does not change by more than 2 inches of water at 100 percent load plus or minus 10 percent from the pressure drop across the catalyst that was measured during the initial performance test; and b. maintain the temperature of your stationary RICE exhaust so that the catalyst inlet temperature is greater than or equal to 450 °F and less than or equal to 1350 °F.[1]
2. Existing CI stationary RICE >500 HP complying with the requirement to limit or reduce the concentration of CO in the stationary RICE exhaust and using an oxidation catalyst.	a. maintain your catalyst so that the pressure drop across the catalyst does not change by more than 2 inches of water from the pressure drop across the catalyst that was measured during the initial performance test; and b. maintain the temperature of your stationary RICE exhaust so that the catalyst inlet temperature is greater than or equal to 450 °F and less than or equal to 1350 °F.[1]
3. New and reconstructed 2SLB and CI stationary RICE >500 HP located at a major source of HAP emissions and new and reconstructed 4SLB stationary RICE ≥250 HP located at a major source of HAP emissions complying with the requirement to reduce CO emissions and not using an oxidation catalyst; and New and reconstructed 2SLB and CI stationary RICE >500 HP located at a major source of HAP emissions and new and reconstructed 4SLB stationary RICE ≥250 HP located at a major source of HAP emissions complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust and not using an oxidation catalyst; and	Comply with any operating limitations approved by the Administrator.

TABLE 2b TO SUBPART ZZZZ OF PART 63—OPERATING LIMITATIONS FOR NEW AND RECONSTRUCTED 2SLB AND CI STATIONARY RICE >500 HP LOCATED AT A MAJOR SOURCE OF HAP EMISSIONS, NEW AND RECONSTRUCTED 4SLB STATIONARY RICE ≥250 HP LOCATED AT A MAJOR SOURCE OF HAP EMISSIONS, EXISTING CI STATIONARY RICE >500 HP—Continued

For each . . .	You must meet the following operating limitation, except during periods of startup . . .
existing CI stationary RICE >500 HP complying with the requirement to limit or reduce the concentration of CO in the stationary RICE exhaust and not using an oxidation catalyst.	

[1] Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.8(f) for a different temperature range.

■ 31. Table 2c to Subpart ZZZZ of Part 63 is revised to read as follows:

As stated in §§ 63.6600, 63.6602, and 63.6640, you must comply with the following requirements for existing compression ignition stationary RICE located at a major source of HAP emissions and existing spark ignition stationary RICE ≤500 HP located at a major source of HAP emissions:

TABLE 2c TO SUBPART ZZZZ OF PART 63—REQUIREMENTS FOR EXISTING COMPRESSION IGNITION STATIONARY RICE LOCATED AT A MAJOR SOURCE OF HAP EMISSIONS AND EXISTING SPARK IGNITION STATIONARY RICE >500 HP LOCATED AT A MAJOR SOURCE OF HAP EMISSIONS

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
1. Emergency stationary CI RICE and black start stationary CI RICE [1].	a. Change oil and filter every 500 hours of operation or annually, whichever comes first.[2] b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.[3]	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.[3]
2. Non-Emergency, non-black start stationary CI RICE <100 HP.	a. Change oil and filter every 1,000 hours of operation or annually, whichever comes first.[2] b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.[3]	
3. Non-Emergency, non-black start CI stationary RICE 100≤HP≤300 HP.	Limit concentration of CO in the stationary RICE exhaust to 230 ppmvd or less at 15 percent O_2.	
4. Non-Emergency, non-black start CI stationary RICE 300>HP≤500.	a. Limit concentration of CO in the stationary RICE exhaust to 49 ppmvd or less at 15 percent O_2; or b. Reduce CO emissions by 70 percent or more.	
5. Non-Emergency, non-black start stationary CI RICE >500 HP.	a. Limit concentration of CO in the stationary RICE exhaust to 23 ppmvd or less at 15 percent O_2; or b. Reduce CO emissions by 70 percent or more.	
6. Emergency stationary SI RICE and black start stationary SI RICE.[1]	a. Change oil and filter every 500 hours of operation or annually, whichever comes first;[2] b. Inspect spark plugs every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.[3]	
7. Non-Emergency, non-black start stationary SI RICE <100 HP that are not 2SLB stationary RICE.	a. Change oil and filter every 1,440 hours of operation or annually, whichever comes first;[2] b. Inspect spark plugs every 1,440 hours of operation or annually, whichever comes first, and replace as necessary; c. Inspect all hoses and belts every 1,440 hours of operation or annually, whichever comes first, and replace as necessary.[3]	

TABLE 2c TO SUBPART ZZZZ OF PART 63—REQUIREMENTS FOR EXISTING COMPRESSION IGNITION STATIONARY RICE LOCATED AT A MAJOR SOURCE OF HAP EMISSIONS AND EXISTING SPARK IGNITION STATIONARY RICE >500 HP LOCATED AT A MAJOR SOURCE OF HAP EMISSIONS—Continued

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
8. Non-Emergency, non-black start 2SLB stationary SI RICE <100 HP.	a. Change oil and filter every 4,320 hours of operation or annually, whichever comes first;[2] b. Inspect spark plugs every 4,320 hours of operation or annually, whichever comes first, and replace as necessary; c. Inspect all hoses and belts every 4,320 hours of operation or annually, whichever comes first, and replace as necessary.[3]	
9. Non-emergency, non-black start 2SLB stationary RICE 100≤HP≤500.	Limit concentration of CO in the stationary RICE exhaust to 225 ppmvd or less at 15 percent O_2.	
10. Non-emergency, non-black start 4SLB stationary RICE 100≤HP≤500.	Limit concentration of CO in the stationary RICE exhaust to 47 ppmvd or less at 15 percent O_2.	
11. Non-emergency, non-black start 4SRB stationary RICE 100≤HP≤500.	Limit concentration of formaldehyde in the stationary RICE exhaust to 10.3 ppmvd or less at 15 percent O_2.	
12. Non-emergency, non-black start stationary RICE 100≤HP≤500 which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis.	Limit concentration of CO in the stationary RICE exhaust to 177 ppmvd or less at 15 percent O_2.	

[1] If an emergency engine is operating during an emergency and it is not possible to shut down the engine in order to perform the work practice requirements on the schedule required in Table 2c of this subpart, or if performing the work practice on the required schedule would otherwise pose an unacceptable risk under federal, state, or local law, the work practice can be delayed until the emergency is over or the unacceptable risk under federal, state, or local law has abated. The work practice should be performed as soon as practicable after the emergency has ended or the unacceptable risk under federal, state, or local law has abated. Sources must report any failure to perform the work practice on the schedule required and the federal, state or local law under which the risk was deemed unacceptable.

[2] Sources have the option to utilize an oil analysis program as described in § 63.6625(i) or (j) in order to extend the specified oil change requirement in Table 2c of this subpart.

[3] Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.6(g) for alternative work practices.

■ 32. Table 2d to Subpart ZZZZ of Part 63 is revised to read as follows:

As stated in §§ 63.6603 and 63.6640, you must comply with the following requirements for existing stationary RICE located at area sources of HAP emissions:

TABLE 2d TO SUBPART ZZZZ OF PART 63—REQUIREMENTS FOR EXISTING STATIONARY RICE LOCATED AT AREA SOURCES OF HAP EMISSIONS

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
1. Non-Emergency, non-black start CI stationary RICE ≤300 HP.	a. Change oil and filter every 1,000 hours of operation or annually, whichever comes first;[1] b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.
2. Non-Emergency, non-black start CI stationary RICE 300<HP≤500.	a. Limit concentration of CO in the stationary RICE exhaust to 49 ppmvd at 15 percent O_2; or b. Reduce CO emissions by 70 percent or more.	
3. Non-Emergency, non-black start CI stationary RICE >500 HP.	a. Limit concentration of CO in the stationary RICE exhaust to 23 ppmvd at 15 percent O_2; or b. Reduce CO emissions by 70 percent or more.	
4. Emergency stationary CI RICE and black start stationary CI RICE.[2]	a. Change oil and filter every 500 hours of operation or annually, whichever comes first;[1] b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; and	

TABLE 2d TO SUBPART ZZZZ OF PART 63—REQUIREMENTS FOR EXISTING STATIONARY RICE LOCATED AT AREA SOURCES OF HAP EMISSIONS—Continued

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
	c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.	
5. Emergency stationary SI RICE; black start stationary SI RICE; non-emergency, non-black start 4SLB stationary RICE >500 HP that operate 24 hours or less per calendar year; non-emergency, non-black start 4SRB stationary RICE >500 HP that operate 24 hours or less per calendar year.[2]	a. Change oil and filter every 500 hours of operation or annually, whichever comes first;[1]; b. Inspect spark plugs every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; and c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.	
6. Non-emergency, non-black start 2SLB stationary RICE.	a. Change oil and filter every 4,320 hours of operation or annually, whichever comes first;[1] b. Inspect spark plugs every 4,320 hours of operation or annually, whichever comes first, and replace as necessary; and c. Inspect all hoses and belts every 4,320 hours of operation or annually, whichever comes first, and replace as necessary.	
7. Non-emergency, non-black start 4SLB stationary RICE ≤500 HP.	a. Change oil and filter every 1,440 hours of operation or annually, whichever comes first;[1] b. Inspect spark plugs every 1,440 hours of operation or annually, whichever comes first, and replace as necessary; and c. Inspect all hoses and belts every 1,440 hours of operation or annually, whichever comes first, and replace as necessary.	
8. Non-emergency, non-black start 4SLB remote stationary RICE >500 HP.	a. Change oil and filter every 2,160 hours of operation or annually, whichever comes first;[1] b. Inspect spark plugs every 2,160 hours of operation or annually, whichever comes first, and replace as necessary; and c. Inspect all hoses and belts every 2,160 hours of operation or annually, whichever comes first, and replace as necessary.	
9. Non-emergency, non-black start 4SLB stationary RICE >500 HP that are not remote stationary RICE and that operate more than 24 hours per calendar year.	Install an oxidation catalyst to reduce HAP emissions from the stationary RICE.	
10. Non-emergency, non-black start 4SRB stationary RICE ≤500 HP.	a. Change oil and filter every 1,440 hours of operation or annually, whichever comes first;[1] b. Inspect spark plugs every 1,440 hours of operation or annually, whichever comes first, and replace as necessary; and c. Inspect all hoses and belts every 1,440 hours of operation or annually, whichever comes first, and replace as necessary.	
11. Non-emergency, non-black start 4SRB remote stationary RICE >500 HP.	a. Change oil and filter every 2,160 hours of operation or annually, whichever comes first;[1] b. Inspect spark plugs every 2,160 hours of operation or annually, whichever comes first, and replace as necessary; and c. Inspect all hoses and belts every 2,160 hours of operation or annually, whichever comes first, and replace as necessary.	
12. Non-emergency, non-black start 4SRB stationary RICE >500 HP that are not remote stationary RICE and that operate more than 24 hours per calendar year.	Install NSCR to reduce HAP emissions from the stationary RICE.	

TABLE 2d TO SUBPART ZZZZ OF PART 63—REQUIREMENTS FOR EXISTING STATIONARY RICE LOCATED AT AREA SOURCES OF HAP EMISSIONS—Continued

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
13. Non-emergency, non-black start stationary RICE which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis.	a. Change oil and filter every 1,440 hours of operation or annually, whichever comes first;[1] b. Inspect spark plugs every 1,440 hours of operation or annually, whichever comes first, and replace as necessary; and c. Inspect all hoses and belts every 1,440 hours of operation or annually, whichever comes first, and replace as necessary.	

[1] Sources have the option to utilize an oil analysis program as described in § 63.6625(i) or (j) in order to extend the specified oil change requirement in Table 2d of this subpart.

[2] If an emergency engine is operating during an emergency and it is not possible to shut down the engine in order to perform the management practice requirements on the schedule required in Table 2d of this subpart, or if performing the management practice on the required schedule would otherwise pose an unacceptable risk under federal, state, or local law, the management practice can be delayed until the emergency is over or the unacceptable risk under federal, state, or local law has abated. The management practice should be performed as soon as practicable after the emergency has ended or the unacceptable risk under federal, state, or local law has abated. Sources must report any failure to perform the management practice on the schedule required and the federal, state or local law under which the risk was deemed unacceptable.

■ 33. Table 3 to Subpart ZZZZ of Part 63 is revised to read as follows:

As stated in §§ 63.6615 and 63.6620, you must comply with the following subsequent performance test requirements:

TABLE 3 TO SUBPART ZZZZ OF PART 63—SUBSEQUENT PERFORMANCE TESTS

For each . . .	Complying with the requirement to . . .	You must . . .
1. New or reconstructed 2SLB stationary RICE >500 HP located at major sources; new or reconstructed 4SLB stationary RICE ≥250 HP located at major sources; and new or reconstructed CI stationary RICE >500 HP located at major sources.	Reduce CO emissions and not using a CEMS	Conduct subsequent performance tests semi-annually.[1]
2. 4SRB stationary RICE ≥5,000 HP located at major sources.	Reduce formaldehyde emissions	Conduct subsequent performance tests semi-annually.[1]
3. Stationary RICE >500 HP located at major sources and new or reconstructed 4SLB stationary RICE 250≤HP≤500 located at major sources.	Limit the concentration of formaldehyde in the stationary RICE exhaust.	Conduct subsequent performance tests semi-annually.[1]
4. Existing non-emergency, non-black start CI stationary RICE >500 HP that are not limited use stationary RICE.	Limit or reduce CO emissions and not using a CEMS.	Conduct subsequent performance tests every 8,760 hours or 3 years, whichever comes first.
5. Existing non-emergency, non-black start CI stationary RICE >500 HP that are limited use stationary RICE.	Limit or reduce CO emissions and not using a CEMS.	Conduct subsequent performance tests every 8,760 hours or 5 years, whichever comes first.

[1] After you have demonstrated compliance for two consecutive tests, you may reduce the frequency of subsequent performance tests to annually. If the results of any subsequent annual performance test indicate the stationary RICE is not in compliance with the CO or formaldehyde emission limitation, or you deviate from any of your operating limitations, you must resume semiannual performance tests.

■ 34. Table 4 to Subpart ZZZZ of Part 63 is revised to read as follows:

As stated in §§ 63.6610, 63.6611, 63.6612, 63.6620, and 63.6640, you must comply with the following requirements for performance tests for stationary RICE:

TABLE 4 TO SUBPART ZZZZ OF PART 63. REQUIREMENTS FOR PERFORMANCE TESTS

For each . . .	Complying with the requirement to . . .	You must . . .	Using . . .	According to the following requirements . . .
1. 2SLB, 4SLB, and CI stationary RICE.	a. reduce CO emissions.	i. Measure the O_2 at the inlet and outlet of the control device; and	(1) Method 3 or 3A or 3B of 40 CFR part 60, appendix A, or ASTM Method D6522–00 (Reapproved 2005).[a c]	(a) Measurements to determine O_2 must be made at the same time as the measurements for CO concentration.
		ii. Measure the CO at the inlet and the outlet of the control device.	(1) ASTM D6522–00 (Reapproved 2005)[a b c] or Method 10 of 40 CFR part 60, appendix A.	(a) The CO concentration must be at 15 percent O_2, dry basis.

TABLE 4 TO SUBPART ZZZZ OF PART 63. REQUIREMENTS FOR PERFORMANCE TESTS—Continued

For each . . .	Complying with the requirement to . . .	You must . . .	Using . . .	According to the following requirements . . .
2. 4SRB stationary RICE.	a. reduce formaldehyde emissions.	i. Select the sampling port location and the number of traverse points; and	(1) Method 1 or 1A of 40 CFR part 60, appendix A § 63.7(d)(1)(i).	(a) sampling sites must be located at the inlet and outlet of the control device.
		ii. Measure O_2 at the inlet and outlet of the control device; and	(1) Method 3 or 3A or 3B of 40 CFR part 60, appendix A, or ASTM Method D6522–00 (Reapproved 2005).[a]	(a) measurements to determine O_2 concentration must be made at the same time as the measurements for formaldehyde or THC concentration.
		iii. Measure moisture content at the inlet and outlet of the control device; and	(1) Method 4 of 40 CFR part 60, appendix A, or Test Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348–03.[a]	(a) measurements to determine moisture content must be made at the same time and location as the measurements for formaldehyde or THC concentration.
		iv. If demonstrating compliance with the formaldehyde percent reduction requirement, measure formaldehyde at the inlet and the outlet of the control device.	(1) Method 320 or 323 of 40 CFR part 63, appendix A; or ASTM D6348–03,[a] provided in ASTM D6348–03 Annex A5 (Analyte Spiking Technique), the percent R must be greater than or equal to 70 and less than or equal to 130.	(a) formaldehyde concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
		v. If demonstrating compliance with the THC percent reduction requirement, measure THC at the inlet and the outlet of the control device.	(1) Method 25A, reported as propane, of 40 CFR part 60, appendix A.	(a) THC concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
3. Stationary RICE.	a. limit the concentration of formaldehyde or CO in the stationary RICE exhaust.	i. Select the sampling port location and the number of traverse points; and	(1) Method 1 or 1A of 40 CFR part 60, appendix A § 63.7(d)(1)(i).	(a) if using a control device, the sampling site must be located at the outlet of the control device.
		ii. Determine the O_2 concentration of the stationary RICE exhaust at the sampling port location; and	(1) Method 3 or 3A or 3B of 40 CFR part 60, appendix A, or ASTM Method D6522–00 (Reapproved 2005).[a]	(a) measurements to determine O_2 concentration must be made at the same time and location as the measurements for formaldehyde or CO concentration.
		iii. Measure moisture content of the stationary RICE exhaust at the sampling port location; and	(1) Method 4 of 40 CFR part 60, appendix A, or Test Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348–03.[a]	(a) measurements to determine moisture content must be made at the same time and location as the measurements for formaldehyde or CO concentration.
		iv. Measure formaldehyde at the exhaust of the stationary RICE; or	(1) Method 320 or 323 of 40 CFR part 63, appendix A; or ASTM D6348–03,[a] provided in ASTM D6348–03 Annex A5 (Analyte Spiking Technique), the percent R must be greater than or equal to 70 and less than or equal to 130.	(a) Formaldehyde concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
		v. measure CO at the exhaust of the stationary RICE.	(1) Method 10 of 40 CFR part 60, appendix A, ASTM Method D6522–00 (2005),[a c] Method 320 of 40 CFR part 63, appendix A, or ASTM D6348–03.[a]	(a) CO concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.

[a] Incorporated by reference, see 40 CFR 63.14. You may also obtain copies from University Microfilms International, 300 North Zeeb Road, Ann Arbor, MI 48106.
[b] You may also use Method 320 of 40 CFR part 63, appendix A, or ASTM D6348–03.
[c] ASTM–D6522–00 (2005) may be used to test both CI and SI stationary RICE.

■ 35. Table 5 to Subpart ZZZZ of Part 63 is revised to read as follows:

As stated in §§ 63.6612, 63.6625 and 63.6630, you must initially comply with the emission and operating limitations as required by the following:

TABLE 5 TO SUBPART ZZZZ OF PART 63—INITIAL COMPLIANCE WITH EMISSION LIMITATIONS, OPERATING LIMITATIONS, AND OTHER REQUIREMENTS

For each . . .	Complying with the requirement to . . .	You have demonstrated initial compliance if . . .
1. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP.	a. Reduce CO emissions and using oxidation catalyst, and using a CPMS.	i. The average reduction of emissions of CO determined from the initial performance test achieves the required CO percent reduction; and ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in § 63.6625(b); and iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.
2. Non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP.	a. Limit the concentration of CO, using oxidation catalyst, and using a CPMS.	i. The average CO concentration determined from the initial performance test is less than or equal to the CO emission limitation; and ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in § 63.6625(b); and iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.
3. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP.	a. Reduce CO emissions and not using oxidation catalyst.	i. The average reduction of emissions of CO determined from the initial performance test achieves the required CO percent reduction; and ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in § 63.6625(b); and iii. You have recorded the approved operating parameters (if any) during the initial performance test.
4. Non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP.	a. Limit the concentration of CO, and not using oxidation catalyst.	i. The average CO concentration determined from the initial performance test is less than or equal to the CO emission limitation; and ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in § 63.6625(b); and iii. You have recorded the approved operating parameters (if any) during the initial performance test.
5. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP.	a. Reduce CO emissions, and using a CEMS	i. You have installed a CEMS to continuously monitor CO and either O_2 or CO_2 at both the inlet and outlet of the oxidation catalyst according to the requirements in § 63.6625(a); and ii. You have conducted a performance evaluation of your CEMS using PS 3 and 4A of 40 CFR part 60, appendix B; and iii. The average reduction of CO calculated using § 63.6620 equals or exceeds the required percent reduction. The initial test comprises the first 4-hour period after successful validation of the CEMS. Compliance is based on the average percent reduction achieved during the 4-hour period.
6. Non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP.	a. Limit the concentration of CO, and using a CEMS.	i. You have installed a CEMS to continuously monitor CO and either O_2 or CO_2 at the outlet of the oxidation catalyst according to the requirements in § 63.6625(a); and ii. You have conducted a performance evaluation of your CEMS using PS 3 and 4A of 40 CFR part 60, appendix B; and

TABLE 5 TO SUBPART ZZZZ OF PART 63—INITIAL COMPLIANCE WITH EMISSION LIMITATIONS, OPERATING LIMITATIONS, AND OTHER REQUIREMENTS—Continued

For each . . .	Complying with the requirement to . . .	You have demonstrated initial compliance if . . .
		iii. The average concentration of CO calculated using § 63.6620 is less than or equal to the CO emission limitation. The initial test comprises the first 4-hour period after successful validation of the CEMS. Compliance is based on the average concentration measured during the 4-hour period.
7. Non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP.	a. Reduce formaldehyde emissions and using NSCR.	i. The average reduction of emissions of formaldehyde determined from the initial performance test is equal to or greater than the required formaldehyde percent reduction, or the average reduction of emissions of THC determined from the initial performance test is equal to or greater than 30 percent; and ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in § 63.6625(b); and iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.
8. Non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP.	a. Reduce formaldehyde emissions and not using NSCR.	i. The average reduction of emissions of formaldehyde determined from the initial performance test is equal to or greater than the required formaldehyde percent reduction or the average reduction of emissions of THC determined from the initial performance test is equal to or greater than 30 percent; and ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in § 63.6625(b); and iii. You have recorded the approved operating parameters (if any) during the initial performance test.
9. New or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP, and existing non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP.	a. Limit the concentration of formaldehyde in the stationary RICE exhaust and using oxidation catalyst or NSCR.	i. The average formaldehyde concentration, corrected to 15 percent O_2, dry basis, from the three test runs is less than or equal to the formaldehyde emission limitation; and ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in § 63.6625(b); and iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.
10. New or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP, and existing non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP.	a. Limit the concentration of formaldehyde in the stationary RICE exhaust and not using oxidation catalyst or NSCR.	i. The average formaldehyde concentration, corrected to 15 percent O_2, dry basis, from the three test runs is less than or equal to the formaldehyde emission limitation; and ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in § 63.6625(b); and iii. You have recorded the approved operating parameters (if any) during the initial performance test.
11. Existing non-emergency stationary RICE 100≤HP≤500 located at a major source of HAP, and existing non-emergency stationary CI RICE 300<HP≤500 located at an area source of HAP.	a. Reduce CO emissions	i. The average reduction of emissions of CO or formaldehyde, as applicable determined from the initial performance test is equal to or greater than the required CO or formaldehyde, as applicable, percent reduction.

TABLE 5 TO SUBPART ZZZZ OF PART 63—INITIAL COMPLIANCE WITH EMISSION LIMITATIONS, OPERATING LIMITATIONS, AND OTHER REQUIREMENTS—Continued

For each . . .	Complying with the requirement to . . .	You have demonstrated initial compliance if . . .
12. Existing non-emergency stationary RICE 100≤HP≤500 located at a major source of HAP, and existing non-emergency stationary CI RICE 300<HP≤500 located at an area source of HAP.	a. Limit the concentration of formaldehyde or CO in the stationary RICE exhaust.	i. The average formaldehyde or CO concentration, as applicable, corrected to 15 percent O_2, dry basis, from the three test runs is less than or equal to the formaldehyde or CO emission limitation, as applicable.
13. Existing non-emergency 4SLB stationary RICE >500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year.	a. Install an oxidation catalyst	i. You have conducted an initial compliance demonstration as specified in § 63.6630(e) to show that the average reduction of emissions of CO is 93 percent or more, or the average CO concentration is less than or equal to 47 ppmvd at 15 percent O_2; ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in § 63.6625(b), or you have installed equipment to automatically shut down the engine if the catalyst inlet temperature exceeds 1350 °F.
14. Existing non-emergency 4SRB stationary RICE >500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year.	a. Install NSCR	i. You have conducted an initial compliance demonstration as specified in § 63.6630(e) to show that the average reduction of emissions of CO is 75 percent or more, the average CO concentration is less than or equal to 270 ppmvd at 15 percent O_2, or the average reduction of emissions of THC is 30 percent or more; ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in § 63.6625(b), or you have installed equipment to automatically shut down the engine if the catalyst inlet temperature exceeds 1250 °F.

■ 36. Table 6 to Subpart ZZZZ of Part 63 is revised to read as follows:

As stated in § 63.6640, you must continuously comply with the emissions and operating limitations and work or management practices as required by the following:

TABLE 6 TO SUBPART ZZZZ OF PART 63—CONTINUOUS COMPLIANCE WITH EMISSION LIMITATIONS, AND OTHER REQUIREMENTS

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
1. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, and new or reconstructed non-emergency CI stationary RICE >500 HP located at a major source of HAP.	a. Reduce CO emissions and using an oxidation catalyst, and using a CPMS.	i. Conducting semiannual performance tests for CO to demonstrate that the required CO percent reduction is achieved [a]; and ii. Collecting the catalyst inlet temperature data according to § 63.6625(b); and iii. Reducing these data to 4-hour rolling averages; and iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
2. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, and new or reconstructed non-emergency CI stationary RICE >500 HP located at a major source of HAP.	a. Reduce CO emissions and not using an oxidation catalyst, and using a CPMS.	i. Conducting semiannual performance tests for CO to demonstrate that the required CO percent reduction is achieved [a]; and ii. Collecting the approved operating parameter (if any) data according to § 63.6625(b); and iii. Reducing these data to 4-hour rolling averages; and

TABLE 6 TO SUBPART ZZZZ OF PART 63—CONTINUOUS COMPLIANCE WITH EMISSION LIMITATIONS, AND OTHER REQUIREMENTS—Continued

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.
3. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, new or reconstructed non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP.	a. Reduce CO emissions or limit the concentration of CO in the stationary RICE exhaust, and using a CEMS.	i. Collecting the monitoring data according to § 63.6625(a), reducing the measurements to 1-hour averages, calculating the percent reduction or concentration of CO emissions according to § 63.6620; and ii. Demonstrating that the catalyst achieves the required percent reduction of CO emissions over the 4-hour averaging period, or that the emission remain at or below the CO concentration limit; and iii. Conducting an annual RATA of your CEMS using PS 3 and 4A of 40 CFR part 60, appendix B, as well as daily and periodic data quality checks in accordance with 40 CFR part 60, appendix F, procedure 1.
4. Non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP.	a. Reduce formaldehyde emissions and using NSCR.	i. Collecting the catalyst inlet temperature data according to § 63.6625(b); and ii. Reducing these data to 4-hour rolling averages; and iii. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and iv. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
5. Non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP.	a. Reduce formaldehyde emissions and not using NSCR.	i. Collecting the approved operating parameter (if any) data according to § 63.6625(b); and ii. Reducing these data to 4-hour rolling averages; and iii. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.
6. Non-emergency 4SRB stationary RICE with a brake HP ≥5,000 located at a major source of HAP.	a. Reduce formaldehyde emissions	Conducting semiannual performance tests for formaldehyde to demonstrate that the required formaldehyde percent reduction is achieved, or to demonstrate that the average reduction of emissions of THC determined from the performance test is equal to or greater than 30 percent.[a]
7. New or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP and new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP.	a. Limit the concentration of formaldehyde in the stationary RICE exhaust and using oxidation catalyst or NSCR.	i. Conducting semiannual performance tests for formaldehyde to demonstrate that your emissions remain at or below the formaldehyde concentration limit[a]; and ii. Collecting the catalyst inlet temperature data according to § 63.6625(b); and iii. Reducing these data to 4-hour rolling averages; and iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.

TABLE 6 TO SUBPART ZZZZ OF PART 63—CONTINUOUS COMPLIANCE WITH EMISSION LIMITATIONS, AND OTHER REQUIREMENTS—Continued

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
8. New or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP and new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP.	a. Limit the concentration of formaldehyde in the stationary RICE exhaust and not using oxidation catalyst or NSCR.	i. Conducting semiannual performance tests for formaldehyde to demonstrate that your emissions remain at or below the formaldehyde concentration limit[a]; and ii. Collecting the approved operating parameter (if any) data according to § 63.6625(b); and iii. Reducing these data to 4-hour rolling averages; and iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.
9. Existing emergency and black start stationary RICE ≤500 HP located at a major source of HAP, existing non-emergency stationary RICE <100 HP located at a major source of HAP, existing emergency and black start stationary RICE located at an area source of HAP, existing non-emergency stationary CI RICE ≤300 HP located at an area source of HAP, existing non-emergency 2SLB stationary RICE located at an area source of HAP, existing non-emergency stationary SI RICE located at an area source of HAP which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, existing non-emergency 4SLB and 4SRB stationary RICE ≤500 HP located at an area source of HAP, existing non-emergency 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP that operate 24 hours or less per calendar year, and existing non-emergency 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP that are remote stationary RICE.	a. Work or Management practices	i. Operating and maintaining the stationary RICE according to the manufacturer's emission-related operation and maintenance instructions; or ii. Develop and follow your own maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions.
10. Existing stationary CI RICE >500 HP that are not limited use stationary RICE.	a. Reduce CO emissions, or limit the concentration of CO in the stationary RICE exhaust, and using oxidation catalyst.	i. Conducting performance tests every 8,760 hours or 3 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and ii. Collecting the catalyst inlet temperature data according to § 63.6625(b); and iii. Reducing these data to 4-hour rolling averages; and iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
11. Existing stationary CI RICE >500 HP that are not limited use stationary RICE.	a. Reduce CO emissions, or limit the concentration of CO in the stationary RICE exhaust, and not using oxidation catalyst.	i. Conducting performance tests every 8,760 hours or 3 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and ii. Collecting the approved operating parameter (if any) data according to § 63.6625(b); and

TABLE 6 TO SUBPART ZZZZ OF PART 63—CONTINUOUS COMPLIANCE WITH EMISSION LIMITATIONS, AND OTHER REQUIREMENTS—Continued

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
		iii. Reducing these data to 4-hour rolling averages; and iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.
12. Existing limited use CI stationary RICE >500 HP.	a. Reduce CO emissions or limit the concentration of CO in the stationary RICE exhaust, and using an oxidation catalyst.	i. Conducting performance tests every 8,760 hours or 5 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and ii. Collecting the catalyst inlet temperature data according to § 63.6625(b); and iii. Reducing these data to 4-hour rolling averages; and iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
13. Existing limited use CI stationary RICE >500 HP.	a. Reduce CO emissions or limit the concentration of CO in the stationary RICE exhaust, and not using an oxidation catalyst.	i. Conducting performance tests every 8,760 hours or 5 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and ii. Collecting the approved operating parameter (if any) data according to § 63.6625(b); and iii. Reducing these data to 4-hour rolling averages; and iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.
14. Existing non-emergency 4SLB stationary RICE >500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year.	a. Install an oxidation catalyst	i. Conducting annual compliance demonstrations as specified in § 63.6640(c) to show that the average reduction of emissions of CO is 93 percent or more, or the average CO concentration is less than or equal to 47 ppmvd at 15 percent O_2; and either ii. Collecting the catalyst inlet temperature data according to § 63.6625(b), reducing these data to 4-hour rolling averages; and maintaining the 4-hour rolling averages within the limitation of greater than 450 °F and less than or equal to 1350 °F for the catalyst inlet temperature; or iii. Immediately shutting down the engine if the catalyst inlet temperature exceeds 1350 °F.

TABLE 6 TO SUBPART ZZZZ OF PART 63—CONTINUOUS COMPLIANCE WITH EMISSION LIMITATIONS, AND OTHER REQUIREMENTS—Continued

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
15. Existing non-emergency 4SRB stationary RICE >500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year.	a. Install NSCR	i. Conducting annual compliance demonstrations as specified in § 63.6640(c) to show that the average reduction of emissions of CO is 75 percent or more, the average CO concentration is less than or equal to 270 ppmvd at 15 percent O_2, or the average reduction of emissions of THC is 30 percent or more; and either ii. Collecting the catalyst inlet temperature data according to § 63.6625(b), reducing these data to 4-hour rolling averages; and maintaining the 4-hour rolling averages within the limitation of greater than or equal to 750 °F and less than or equal to 1250 °F for the catalyst inlet temperature; or iii. Immediately shutting down the engine if the catalyst inlet temperature exceeds 1250 °F.

[a] After you have demonstrated compliance for two consecutive tests, you may reduce the frequency of subsequent performance tests to annually. If the results of any subsequent annual performance test indicate the stationary RICE is not in compliance with the CO or formaldehyde emission limitation, or you deviate from any of your operating limitations, you must resume semiannual performance tests.

■ 37. Table 7 to Subpart ZZZZ of Part 63 is revised to read as follows:

As stated in § 63.6650, you must comply with the following requirements for reports:

TABLE 7 TO SUBPART ZZZZ OF PART 63—REQUIREMENTS FOR REPORTS

For each . . .	You must submit a . . .	The report must contain . . .	You must submit the report . . .
1. Existing non-emergency, non-black start stationary RICE 100≤HP≤500 located at a major source of HAP; existing non-emergency, non-black start stationary CI RICE >500 HP located at a major source of HAP; existing non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP; existing non-emergency, non-black start stationary CI RICE >300 HP located at an area source of HAP; new or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP; and new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP.	Compliance report	a. If there are no deviations from any emission limitations or operating limitations that apply to you, a statement that there were no deviations from the emission limitations or operating limitations during the reporting period. If there were no periods during which the CMS, including CEMS and CPMS, was out-of-control, as specified in § 63.8(c)(7), a statement that there were not periods during which the CMS was out-of-control during the reporting period; or	i. Semiannually according to the requirements in § 63.6650(b)(1)–(5) for engines that are not limited use stationary RICE subject to numerical emission limitations; and ii. Annually according to the requirements in § 63.6650(b)(6)–(9) for engines that are limited use stationary RICE subject to numerical emission limitations.
		b. If you had a deviation from any emission limitation or operating limitation during the reporting period, the information in § 63.6650(d). If there were periods during which the CMS, including CEMS and CPMS, was out-of-control, as specified in § 63.8(c)(7), the information in § 63.6650(e); or	i. Semiannually according to the requirements in § 63.6650(b).
		c. If you had a malfunction during the reporting period, the information in § 63.6650(c)(4).	i. Semiannually according to the requirements in § 63.6650(b).

TABLE 7 TO SUBPART ZZZZ OF PART 63—REQUIREMENTS FOR REPORTS—Continued

For each . . .	You must submit a . . .	The report must contain . . .	You must submit the report . . .
2. New or reconstructed non-emergency stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis.	Report	a. The fuel flow rate of each fuel and the heating values that were used in your calculations, and you must demonstrate that the percentage of heat input provided by landfill gas or digester gas, is equivalent to 10 percent or more of the gross heat input on an annual basis; and	i. Annually, according to the requirements in § 63.6650.
		b. The operating limits provided in your federally enforceable permit, and any deviations from these limits; and	i. See item 2.a.i.
		c. Any problems or errors suspected with the meters.	i. See item 2.a.i.
3. Existing non-emergency, non-black start 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP that are not remote stationary RICE and that operate more than 24 hours per calendar year.	Compliance report	a. The results of the annual compliance demonstration, if conducted during the reporting period.	i. Semiannually according to the requirements in § 63.6650(b)(1)–(5).
4. Emergency stationary RICE that operate or are contractually obligated to be available for more than 15 hours per year for the purposes specified in § 63.6640(f)(2)(ii) and (iii) or that operate for the purposes specified in § 63.6640(f)(4)(ii).	Report	a. The information in § 63.6650(h)(1).	i. annually according to the requirements in § 63.6650(h)(2)–(3).

■ 38. Table 8 to Subpart ZZZZ of Part 63 is amended by:

■ a. Revising the entry for § 63.8(c)(1)(i);

■ b. Revising the entry for § 63.8(c)(1)(iii); and

■ c. Revising the entry for § 63.10(b)(1) to read as follows:

As stated in § 63.6665, you must comply with the following applicable general provisions.

TABLE 8 TO SUBPART ZZZZ OF PART 63—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART ZZZZ

General Provisions Citation	Subject of Citation	Applies to Subpart	Explanation
* * *	* * *	* * *	
§ 63.8(c)(1)(i)	Routine and predictable SSM	No	
* * *	* * *	* * *	
§ 63.8(c)(1)(iii)	Compliance with operation and maintenance requirements.	No	
* * *	* * *	* * *	
§ 63.10(b)(1)	Record retention	Yes	Except that the most recent 2 years of data do not have to be retained on site.
* * *	* * *	* * *	

■ 39. Appendix A to Subpart ZZZZ of Part 63 is added to read as follows:

Appendix A—Protocol for Using an Electrochemical Analyzer to Determine Oxygen and Carbon Monoxide Concentrations From Certain Engines

1.0 Scope and Application. What is this Protocol?

This protocol is a procedure for using portable electrochemical (EC) cells for measuring carbon monoxide (CO) and oxygen (O_2) concentrations in controlled and uncontrolled emissions from existing stationary 4-stroke lean burn and 4-stroke rich burn reciprocating internal combustion engines as specified in the applicable rule.

1.1 Analytes. What does this protocol determine?

This protocol measures the engine exhaust gas concentrations of carbon monoxide (CO) and oxygen (O_2).

Analyte	CAS No.	Sensitivity
Carbon monoxide (CO)	630–08–0	Minimum detectable limit should be 2 percent of the nominal range or 1 ppm, whichever is less restrictive.
Oxygen (O_2)	*7782–44–7*	

1.2 Applicability. When is this protocol acceptable?

This protocol is applicable to 40 CFR part 63, subpart ZZZZ. Because of inherent cross sensitivities of EC cells, you must not apply this protocol to other emissions sources without specific instruction to that effect.

1.3 Data Quality Objectives. How good must my collected data be?

Refer to Section 13 to verify and document acceptable analyzer performance.

1.4 Range. What is the targeted analytical range for this protocol?

The measurement system and EC cell design(s) conforming to this protocol will determine the analytical range for each gas component. The nominal ranges are defined by choosing up-scale calibration gas concentrations near the maximum anticipated flue gas concentrations for CO and O_2, or no more than twice the permitted CO level.

1.5 Sensitivity. What minimum detectable limit will this protocol yield for a particular gas component?

The minimum detectable limit depends on the nominal range and resolution of the specific EC cell used, and the signal to noise ratio of the measurement system. The minimum detectable limit should be 2 percent of the nominal range or 1 ppm, whichever is less restrictive.

2.0 Summary of Protocol

In this protocol, a gas sample is extracted from an engine exhaust system and then conveyed to a portable EC analyzer for measurement of CO and O_2 gas concentrations. This method provides measurement system performance specifications and sampling protocols to ensure reliable data. You may use additions to, or modifications of vendor supplied measurement systems (e.g., heated or unheated sample lines, thermocouples, flow meters, selective gas scrubbers, etc.) to meet the design specifications of this protocol. Do not make changes to the measurement system from the as-verified configuration (Section 3.12).

3.0 Definitions

3.1 Measurement System. The total equipment required for the measurement of CO and O_2 concentrations. The measurement system consists of the following major subsystems:

3.1.1 Data Recorder. A strip chart recorder, computer or digital recorder for logging measurement data from the analyzer output. You may record measurement data from the digital data display manually or electronically.

3.1.2 Electrochemical (EC) Cell. A device, similar to a fuel cell, used to sense the presence of a specific analyte and generate an electrical current output proportional to the analyte concentration.

3.1.3 Interference Gas Scrubber. A device used to remove or neutralize chemical compounds that may interfere with the selective operation of an EC cell.

3.1.4 Moisture Removal System. Any device used to reduce the concentration of moisture in the sample stream so as to protect the EC cells from the damaging effects of condensation and to minimize errors in measurements caused by the scrubbing of soluble gases.

3.1.5 Sample Interface. The portion of the system used for one or more of the following: sample acquisition; sample transport; sample conditioning or protection of the EC cell from any degrading effects of the engine exhaust effluent; removal of particulate matter and condensed moisture.

3.2 Nominal Range. The range of analyte concentrations over which each EC cell is operated (normally 25 percent to 150 percent of up-scale calibration gas value). Several nominal ranges can be used for any given cell so long as the calibration and repeatability checks for that range remain within specifications.

3.3 Calibration Gas. A vendor certified concentration of a specific analyte in an appropriate balance gas.

3.4 Zero Calibration Error. The analyte concentration output exhibited by the EC cell in response to zero-level calibration gas.

3.5 Up-Scale Calibration Error. The mean of the difference between the analyte concentration exhibited by the EC cell and the certified concentration of the up-scale calibration gas.

3.6 Interference Check. A procedure for quantifying analytical interference from components in the engine exhaust gas other than the targeted analytes.

3.7 Repeatability Check. A protocol for demonstrating that an EC cell operated over a given nominal analyte concentration range provides a stable and consistent response and is not significantly affected by repeated exposure to that gas.

3.8 Sample Flow Rate. The flow rate of the gas sample as it passes through the EC cell. In some situations, EC cells can experience drift with changes in flow rate. The flow rate must be monitored and documented during all phases of a sampling run.

3.9 Sampling Run. A timed three-phase event whereby an EC cell's response rises and plateaus in a sample conditioning phase, remains relatively constant during a measurement data phase, then declines during a refresh phase. The sample conditioning phase exposes the EC cell to the gas sample for a length of time sufficient to reach a constant response. The measurement data phase is the time interval during which gas sample measurements can be made that meet the acceptance criteria of this protocol. The refresh phase then purges the EC cells with CO-free air. The refresh phase replenishes requisite O_2 and moisture in the electrolyte reserve and provides a mechanism to de-gas or desorb any interference gas scrubbers or filters so as to enable a stable CO EC cell response. There are four primary types of sampling runs: pre- sampling calibrations; stack gas sampling; post-sampling calibration checks; and measurement system repeatability checks. Stack gas sampling runs can be chained together for extended evaluations, providing all other procedural specifications are met.

3.10 Sampling Day. A time not to exceed twelve hours from the time of the pre-sampling calibration to the post-sampling calibration check. During this time, stack gas sampling runs can be repeated without repeated recalibrations, providing all other sampling specifications have been met.

3.11 Pre-Sampling Calibration/Post-Sampling Calibration Check. The protocols executed at the beginning and end of each sampling day to bracket measurement readings with controlled performance checks.

3.12 Performance-Established Configuration. The EC cell and sampling system configuration that existed at the time that it initially met the performance requirements of this protocol.

4.0 Interferences.

When present in sufficient concentrations, NO and NO_2 are two gas species that have

been reported to interfere with CO concentration measurements. In the likelihood of this occurrence, it is the protocol user's responsibility to employ and properly maintain an appropriate CO EC cell filter or scrubber for removal of these gases, as described in Section 6.2.12.

5.0 Safety. [Reserved]

6.0 Equipment and Supplies.

6.1 What equipment do I need for the measurement system?

The system must maintain the gas sample at conditions that will prevent moisture condensation in the sample transport lines, both before and as the sample gas contacts the EC cells. The essential components of the measurement system are described below.

6.2 Measurement System Components.

6.2.1 Sample Probe. A single extraction-point probe constructed of glass, stainless steel or other non-reactive material, and of length sufficient to reach any designated sampling point. The sample probe must be designed to prevent plugging due to condensation or particulate matter.

6.2.2 Sample Line. Non-reactive tubing to transport the effluent from the sample probe to the EC cell.

6.2.3 Calibration Assembly (optional). A three-way valve assembly or equivalent to introduce calibration gases at ambient pressure at the exit end of the sample probe during calibration checks. The assembly must be designed such that only stack gas or calibration gas flows in the sample line and all gases flow through any gas path filters.

6.2.4 Particulate Filter (optional). Filters before the inlet of the EC cell to prevent accumulation of particulate material in the measurement system and extend the useful life of the components. All filters must be fabricated of materials that are non-reactive to the gas mixtures being sampled.

6.2.5 Sample Pump. A leak-free pump to provide undiluted sample gas to the system at a flow rate sufficient to minimize the response time of the measurement system. If located upstream of the EC cells, the pump must be constructed of a material that is non-reactive to the gas mixtures being sampled.

6.2.8 Sample Flow Rate Monitoring. An adjustable rotameter or equivalent device used to adjust and maintain the sample flow rate through the analyzer as prescribed.

6.2.9 Sample Gas Manifold (optional). A manifold to divert a portion of the sample gas stream to the analyzer and the remainder to a by-pass discharge vent. The sample gas manifold may also include provisions for introducing calibration gases directly to the analyzer. The manifold must be constructed of a material that is non-reactive to the gas mixtures being sampled.

6.2.10 EC cell. A device containing one or more EC cells to determine the CO and O_2 concentrations in the sample gas stream. The EC cell(s) must meet the applicable performance specifications of Section 13 of this protocol.

6.2.11 Data Recorder. A strip chart recorder, computer or digital recorder to make a record of analyzer output data. The data recorder resolution (i.e., readability) must be no greater than 1 ppm for CO; 0.1 percent for O_2; and one degree (either °C or °F) for temperature. Alternatively, you may use a digital or analog meter having the same resolution to observe and manually record the analyzer responses.

6.2.12 Interference Gas Filter or Scrubber. A device to remove interfering compounds upstream of the CO EC cell. Specific interference gas filters or scrubbers used in the performance-established configuration of the analyzer must continue to be used. Such a filter or scrubber must have a means to determine when the removal agent is exhausted. Periodically replace or replenish it in accordance with the manufacturer's recommendations.

7.0 Reagents and Standards. What calibration gases are needed?

7.1 Calibration Gases. CO calibration gases for the EC cell must be CO in nitrogen or CO in a mixture of nitrogen and O_2. Use CO calibration gases with labeled concentration values certified by the manufacturer to be within ± 5 percent of the label value. Dry ambient air (20.9 percent O_2) is acceptable for calibration of the O_2 cell. If needed, any lower percentage O_2 calibration gas must be a mixture of O_2 in nitrogen.

7.1.1 Up-Scale CO Calibration Gas Concentration. Choose one or more up-scale gas concentrations such that the average of the stack gas measurements for each stack gas sampling run are between 25 and 150 percent of those concentrations. Alternatively, choose an up-scale gas that does not exceed twice the concentration of the applicable outlet standard. If a measured gas value exceeds 150 percent of the up-scale CO calibration gas value at any time during the stack gas sampling run, the run must be discarded and repeated.

7.1.2 Up-Scale O_2 Calibration Gas Concentration.

Select an O_2 gas concentration such that the difference between the gas concentration and the average stack gas measurement or reading for each sample run is less than 15 percent O_2. When the average exhaust gas O_2 readings are above 6 percent, you may use dry ambient air (20.9 percent O_2) for the up-scale O_2 calibration gas.

7.1.3 Zero Gas. Use an inert gas that contains less than 0.25 percent of the up-scale CO calibration gas concentration. You may use dry air that is free from ambient CO and other combustion gas products (e.g., CO_2).

8.0 Sample Collection and Analysis

8.1 Selection of Sampling Sites.

8.1.1 Control Device Inlet. Select a sampling site sufficiently downstream of the engine so that the combustion gases should be well mixed. Use a single sampling extraction point near the center of the duct (e.g., within the 10 percent centroidal area), unless instructed otherwise.

8.1.2 Exhaust Gas Outlet. Select a sampling site located at least two stack diameters downstream of any disturbance (e.g., turbocharger exhaust, crossover junction or recirculation take-off) and at least one-half stack diameter upstream of the gas discharge to the atmosphere. Use a single sampling extraction point near the center of the duct (e.g., within the 10 percent centroidal area), unless instructed otherwise.

8.2 Stack Gas Collection and Analysis. Prior to the first stack gas sampling run, conduct that the pre-sampling calibration in accordance with Section 10.1. Use Figure 1 to record all data. Zero the analyzer with zero gas. Confirm and record that the scrubber media color is correct and not exhausted. Then position the probe at the sampling point and begin the sampling run at the same flow rate used during the up-scale calibration. Record the start time. Record all EC cell output responses and the flow rate during the "sample conditioning phase" once per minute until constant readings are obtained. Then begin the "measurement data phase" and record readings every 15 seconds for at least two minutes (or eight readings), or as otherwise required to achieve two continuous minutes of data that meet the specification given in Section 13.1. Finally, perform the "refresh phase" by introducing dry air, free from CO and other combustion gases, until several minute-to-minute readings of consistent value have been obtained. For each run use the "measurement data phase" readings to calculate the average stack gas CO and O_2 concentrations.

8.3 EC Cell Rate. Maintain the EC cell sample flow rate so that it does not vary by more than ± 10 percent throughout the pre-sampling calibration, stack gas sampling and post-sampling calibration check. Alternatively, the EC cell sample flow rate can be maintained within a tolerance range that does not affect the gas concentration readings by more than ± 3 percent, as instructed by the EC cell manufacturer.

9.0 Quality Control (Reserved)

10.0 Calibration and Standardization

10.1 Pre-Sampling Calibration. Conduct the following protocol once for each nominal range to be used on each EC cell before performing a stack gas sampling run on each field sampling day. Repeat the calibration if you replace an EC cell before completing all of the sampling runs. There is no prescribed order for calibration of the EC cells; however, each cell must complete the measurement data phase during calibration. Assemble the measurement system by following the manufacturer's recommended protocols including for preparing and preconditioning the EC cell. Assure the measurement system has no leaks and verify the gas scrubbing agent is not depleted. Use Figure 1 to record all data.

10.1.1 Zero Calibration. For both the O_2 and CO cells, introduce zero gas to the measurement system (e.g., at the calibration assembly) and record the concentration reading every minute until readings are constant for at least two consecutive minutes. Include the time and sample flow rate. Repeat the steps in this section at least once to verify the zero calibration for each component gas.

10.1.2 Zero Calibration Tolerance. For each zero gas introduction, the zero level output must be less than or equal to ± 3 percent of the up-scale gas value or ± 1 ppm, whichever is less restrictive, for the CO channel and less than or equal to ± 0.3 percent O_2 for the O_2 channel.

10.1.3 Up-Scale Calibration. Individually introduce each calibration gas to the measurement system (e.g., at the calibration assembly) and record the start time. Record all EC cell output responses and the flow rate during this ''sample conditioning phase'' once per minute until readings are constant for at least two minutes. Then begin the ''measurement data phase'' and record readings every 15 seconds for a total of two minutes, or as otherwise required. Finally, perform the ''refresh phase'' by introducing dry air, free from CO and other combustion gases, until readings are constant for at least two consecutive minutes. Then repeat the steps in this section at least once to verify the calibration for each component gas. Introduce all gases to flow through the entire sample handling system (i.e., at the exit end of the sampling probe or the calibration assembly).

10.1.4 Up-Scale Calibration Error. The mean of the difference of the ''measurement data phase'' readings from the reported standard gas value must be less than or equal to ± 5 percent or ± 1 ppm for CO or ± 0.5 percent O_2, whichever is less restrictive, respectively. The maximum allowable deviation from the mean measured value of any single ''measurement data phase'' reading must be less than or equal to ± 2 percent or ± 1 ppm for CO or ± 0.5 percent O_2, whichever is less restrictive, respectively.

10.2 Post-Sampling Calibration Check. Conduct a stack gas post-sampling calibration check after the stack gas sampling run or set of runs and within 12 hours of the initial calibration. Conduct up-scale and zero calibration checks using the protocol in Section 10.1. Make no changes to the sampling system or EC cell calibration until all post-sampling calibration checks have been recorded. If either the zero or up-scale calibration error exceeds the respective specification in Sections 10.1.2 and 10.1.4 then all measurement data collected since the previous successful calibrations are invalid and re-calibration and re-sampling are required. If the sampling system is disassembled or the EC cell calibration is adjusted, repeat the calibration check before conducting the next analyzer sampling run.

11.0 Analytical Procedure

The analytical procedure is fully discussed in Section 8.

12.0 Calculations and Data Analysis

Determine the CO and O_2 concentrations for each stack gas sampling run by calculating the mean gas concentrations of the data recorded during the ''measurement data phase''.

13.0 Protocol Performance

Use the following protocols to verify consistent analyzer performance during each field sampling day.

13.1 Measurement Data Phase Performance Check. Calculate the mean of the readings from the ''measurement data phase''. The maximum allowable deviation from the mean for each of the individual readings is ± 2 percent, or ± 1 ppm, whichever is less restrictive. Record the mean value and maximum deviation for each gas monitored. Data must conform to Section 10.1.4. The EC cell flow rate must conform to the specification in Section 8.3.

Example: A measurement data phase is invalid if the maximum deviation of any single reading comprising that mean is greater than ± 2 percent *or ± 1 ppm (the default criteria). For example, if the mean = 30 ppm, single readings of below 29 ppm and above 31 ppm are disallowed*).

13.2 Interference Check. Before the initial use of the EC cell and interference gas scrubber in the field, and semi-annually thereafter, challenge the interference gas scrubber with NO and NO_2 gas standards that are generally recognized as representative of diesel-fueled engine NO and NO_2 emission values. Record the responses displayed by the CO EC cell and other pertinent data on Figure 1 or a similar form.

13.2.1 Interference Response. The combined NO and NO_2 interference response should be less than or equal to ± 5 percent of the up-scale CO calibration gas concentration.

13.3 Repeatability Check. Conduct the following check once for each nominal range that is to be used on the CO EC cell within 5 days prior to each field sampling program. If a field sampling program lasts longer than 5 days, repeat this check every 5 days. Immediately repeat the check if the EC cell is replaced or if the EC cell is exposed to gas concentrations greater than 150 percent of the highest up-scale gas concentration.

13.3.1 Repeatability Check Procedure. Perform a complete EC cell sampling run (all three phases) by introducing the CO calibration gas to the measurement system and record the response. Follow Section 10.1.3. Use Figure 1 to record all data. Repeat the run three times for a total of four complete runs. During the four repeatability check runs, do not adjust the system except where necessary to achieve the correct calibration gas flow rate at the analyzer.

13.3.2 Repeatability Check Calculations. Determine the highest and lowest average ''measurement data phase'' CO concentrations from the four repeatability check runs and record the results on Figure 1 or a similar form. The absolute value of the difference between the maximum and minimum average values recorded must not vary more than ± 3 percent or ± 1 ppm of the up-scale gas value, whichever is less restrictive.

14.0 Pollution Prevention (Reserved)

15.0 Waste Management (Reserved)

16.0 Alternative Procedures (Reserved)

17.0 References

(1) ''Development of an Electrochemical Cell Emission Analyzer Test Protocol'', Topical Report, Phil Juneau, Emission Monitoring, Inc., July 1997.

(2) ''Determination of Nitrogen Oxides, Carbon Monoxide, and Oxygen Emissions from Natural Gas-Fired Engines, Boilers, and Process Heaters Using Portable Analyzers'', EMC Conditional Test Protocol 30 (CTM–30), Gas Research Institute Protocol GRI–96/0008, Revision 7, October 13, 1997.

(3) ''ICAC Test Protocol for Periodic Monitoring'', EMC Conditional Test Protocol 34 (CTM–034), The Institute of Clean Air Companies, September 8, 1999.

(4) ''Code of Federal Regulations'', Protection of Environment, 40 CFR, Part 60, Appendix A, Methods 1–4; 10.

TABLE 1: APPENDIX A—SAMPLING RUN DATA.

Facility_____ Engine I.D._____ Date_____

Run Type: ..... (__) (__) (__) (__)
(X) ..... Pre-Sample Calibration Stack Gas Sample Post-Sample Cal. Check Repeatability Check

Run #	1	1	2	2	3	3	4	4	Time	Scrub. OK	Flow- Rate
Gas	O_2	CO	O_2	CO	O_2	CO	O_2	CO	.....	.....	.....
.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....
Sample Cond. Phase	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....
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Measurement Data Phase ..	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....	.....
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Part II

Environmental Protection Agency

40 CFR Parts 60 and 63

National Emission Standards for Hazardous Air Pollutants for the Portland Cement Manufacturing Industry and Standards of Performance for Portland Cement Plants; Final Rule

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 60 and 63

[EPA–HQ–OAR–2011–0817; FRL–9758–6]

RIN 2060–AQ93

National Emission Standards for Hazardous Air Pollutants for the Portland Cement Manufacturing Industry and Standards of Performance for Portland Cement Plants

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: On July 18, 2012, the EPA proposed amendments to the National Emission Standards for Hazardous Air Pollutants for the Portland Cement Manufacturing Industry and the Standards of Performance for Portland Cement Plants. This final action amends the national emission standards for hazardous air pollutants for the Portland cement industry. The EPA is also promulgating amendments with respect to issues on which it granted reconsideration on May 17, 2011. In addition, the EPA is amending the new source performance standard for particulate matter. These amendments promote flexibility, reduce costs, ease compliance and preserve health benefits. The amendments also address the remand of the national emission standards for hazardous air pollutants for the Portland cement industry by the United States Court of Appeals for the District of Columbia Circuit on December 9, 2011. Finally, the EPA is setting the date for compliance with the existing source national emission standards for hazardous air pollutants to be September 9, 2015.

DATES: This final rule is effective on February 12, 2013. The EPA is setting the compliance date for existing open clinker storage piles to be February 12, 2014.

ADDRESSES: The EPA has established a docket for this action under Docket ID No. EPA–HQ–OAR–2011–0817. All documents in the docket are listed in the *http://www.regulations.gov* Web site. Although listed in the index, some information is not publicly available, for example, confidential business information 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, 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: For questions about this final action, contact Ms. Sharon Nizich, Office of Air Quality Planning and Standards; Sector Policies and Programs Division, Minerals and Manufacturing Group (D243–04); Environmental Protection Agency; Research Triangle Park, NC 27111; telephone number: (919) 541–2825; fax number: (919) 541–5450; email address: *nizich.sharon@epa.gov.* For information about the applicability of the NESHAP or NSPS contact Mr. Patrick Yellin, Monitoring, Assistance and Media Programs Division (2227A), Office of Enforcement and Compliance Assurance, U.S. Environmental Protection Agency, 1200 Pennsylvania Avenue, Washington, DC 20460; telephone number (202) 654–2970; email address *yellin.patrick@epa.gov.*

SUPPLEMENTARY INFORMATION:

Acronyms and Abbreviations. The following acronyms and abbreviations are used in this document.

APCD air pollution control devices
CAA Clean Air Act
CBI confidential business information
CDX Central Data Exchange
CEMS continuous emission monitoring systems
CEDRI Compliance and Emissions Data Reporting Interface
CFR Code of Federal Regulations
CISWI commercial and industrial solid waste incinerators
CMS continuous monitoring system
COMS continuous opacity monitoring system
CO_2 carbon dioxide
CPMS continuous parametric monitoring system
D/F dioxins and furans
EPA Environmental Protection Agency
ESP Electrostatic Precipitators
ERT Electronic Reporting Tool
FR Federal Register
gr/dscf grains per dry standard cubic foot
HAP hazardous air pollutants
Hg mercury
HCl hydrogen chloride
ICR information collection request
Lb/ton pound per ton
MACT maximum achievable control technology
meHg methylmercury
NAICS North American Industry Classification System
NAS National Academy of Science
NESHAP National Emissions Standards for Hazardous Air Pollutants
NHSM Nonhazardous Secondary Materials
NO_X Nitrogen Oxides
NRC National Research Council
NSPS new source performance standards
NTTAA National Technology Transfer and Advancement Act
oHAP Non-dioxin organic hazardous air pollutants
OMB Office of Management and Budget
PCA Portland Cement Association
PM particulate matter
ppm(v) (d,w) parts per million (by volume) (dry, wet)
RATA Relative Accuracy Test Audit
RfD reference dose
RIA regulatory impact analysis
RTC Response to Comment
RTO regenerative thermal oxidizers
SIP state implementation plan
SO_2 Sulphur Dioxide
THC total hydrocarbons
tpy tons per year
TTN Technology Transfer Network
$\mu g/m^3$ micrograms per cubic meter
UPL Upper Prediction Limit
UMRA Unfunded Mandates Reform Act
TEOM Tapered Element Oscillating Microbalance
VCS voluntary consensus standards
WWW worldwide web

Background Information Document. On July 18, 2012 (77 FR 42368), the EPA proposed to amend the Portland cement manufacturing industry NESHAP and the Portland cement plant new source performance standards (NSPS). In this action, we are taking final action on this proposal. A summary of the public comments on the proposal and the EPA's responses to those comments is available in Docket ID Number EPA–HQ–OAR–2011–0817.

Organization of this Document. The information presented in this preamble is organized as follows:

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I. General Information

A. Executive Summary

In this action the EPA is finalizing amendments to the NESHAP for Portland cement plants and to the NSPS for Portland cement plants. These amendments respond to petitions for reconsideration filed by the Portland cement industry and to a decision by the United States Court of Appeals for the District of Columbia Circuit (D.C. Circuit). The EPA is retaining the stack emission standards for mercury, hydrogen chloride (HCl), and total hydrocarbons (THC) under the NESHAP, amending the stack emission standard for particulate matter (PM) under the NESHAP, and making a conforming amendment to the NSPS for PM. The amendments also include provisions which account for commingled HAP emissions from coal mills that are an integral part of the kiln, establish a continuous monitoring regime for parametric monitoring of PM, set work practice standards for startup and shutdown, and revise the compliance date for the PM, mercury, HCl, THC and clinker storage pile existing source standards under the NESHAP. The EPA is also retaining the affirmative defense for civil penalties for violations of emission limits occurring as a result of a malfunction.

These amendments are based on sound technical and legal justifications, and result in cost savings and compliance flexibility for the Portland cement industry. This result is consistent with Executive Order 13563.

1. Purpose of the Regulatory Action

a. Need for the Regulatory Action

The EPA is amending the NESHAP for the Portland cement source category and the NSPS for Portland cement plants issued under sections 112(d) and 111(b) of the Clean Air Act (CAA). The most significant amendment is to the NESHAP and NSPS for PM, to correct monitoring issues with the PM compliance regime as promulgated in the 2010 final rule. As a result of this amendment, the EPA is also setting a compliance date of September 9, 2015, for meeting the PM, mercury, HCl and THC existing source NESHAP.

This final action also addresses the remand by the DC Circuit in *Portland Cement Ass'n* v. *EPA,* 665 F. 3d 177 (DC Cir. 2011). In that case, the court upheld all of the EPA's methodology for establishing the Portland cement NESHAP, denied all petitions for review challenging the NSPS, but also held that the EPA had arbitrarily denied reconsideration of the NESHAP to take into account the effect of the EPA's Nonhazardous Secondary Materials (NHSM) rule on the standards. The NHSM rule, issued after the NESHAP was promulgated, had the effect of reclassifying some cement kilns as commercial and industrial solid waste incinerators (CISWI) and thus could have an effect on the standards. The court also stayed the open storage clinker pile standards.

We are also amending various implementation requirements to provide more compliance flexibility for affected sources. In addition, the amendments address the issues on which the EPA previously granted reconsideration. See 76 FR 28318 (May 17, 2011).

b. Legal Authority for the Regulatory Action

These amendments implement sections 112(d) and 111(b) of the CAA. Section 112 of the CAA establishes a regulatory process to address emissions of hazardous air pollutants (HAP) from stationary sources. After the EPA identifies categories of sources emitting one or more of the HAP listed in section 112(b) of the CAA, section 112(d) requires the EPA to promulgate technology-based NESHAP for those sources. Section 112(i)(3)(A) requires that the compliance date for existing sources shall be ''as expeditiou[s] as practicable,'' but not more than 3 years after a standard's effective date. Section 111 of the CAA requires that NSPS reflect the application of the best system of emission reductions achievable which, taking into consideration the cost of achieving such emission reductions, and any non-air quality health and environmental impact and energy requirements, the Administrator determines has been adequately demonstrated.

2. Summary of Major Provisions

a. PM Emission Standards

As proposed, the EPA is amending the existing and new source PM standards in the NESHAP to require manual stack testing in lieu of PM continuous emission monitoring systems (CEMS) for compliance determinations and requiring that a site-specific parametric operating level be established using a PM continuous parametric monitoring system (CPMS). We are changing the numeric emissions value of those standards for existing sources to 0.07 pounds per ton (lb/ton) clinker based on manual stack testing and 0.02 lb/ton clinker for new and reconstructed sources based on manual stack testing. The PM standards under the NSPS for modified sources are likewise amended to 0.07 lb/ton clinker based on manual stack testing and 0.02 lb/ton clinker for new and reconstructed sources based on manual stack testing.

b. Response to Remand

Consistent with the court's remand, the EPA has removed all of the CISWI kilns from the database used to set the 2010 existing source standards for PM,

mercury, HCl and THC. This analysis informed the level of the final standards discussed immediately below.

c. Other Emissions Standards

As proposed, the EPA is changing the alternative organic HAP (oHAP) standard from 9 parts per million (ppm) to 12 ppm. The EPA is not changing the existing or new source standards for mercury, THC or HCl.

d. Standards During Startup and Shutdown

The EPA is amending the emission standards applicable during periods of startup and shutdown from numerical standards to work practice standards.

e. Compliance Dates for NESHAP

As proposed, the EPA is establishing a compliance date of September 9, 2015, for existing source standards for PM, mercury, HCl and THC. The EPA is establishing February 12, 2014, as the compliance date for the standards for existing open clinker storage piles. New source standards continue to apply to all sources which commenced construction or reconstruction after May 6, 2009.

f. Final Action on Reconsideration

The EPA is also taking final action on the remaining issues on which it granted reconsideration on May 17, 2011.

3. Cost Impacts of These Amendments

We estimate that revising the means of demonstrating compliance for the PM, alternative organic HAP standards and requiring work practices for open clinker storage piles will save industry $52 million annually.

4. Summary of Final Standards

Table 1 shows the final standards for the Portland Cement Manufacturing Industry NESHAP and the Portland Cement Plants NSPS.

TABLE 1—EXISTING AND NEW SOURCE STANDARDS

Pollutant	Existing source standard	New source standard
Mercury	55 lb/MM tons clinker	21 lb/MM tons clinker.
THC	24 ppmvd	24 ppmvd.
PM	0.07 lb/ton [a] clinker (3-run test average)	0.02 lb/ton [b] clinker (3-run test average).
HCl	3 ppmvd	3 ppmvd.
Organic HAP (alternative to Total Hydrocarbons).	12 ppmvd	12 ppmvd.

[a] Also applies to NSPS modified sources.
[b] Also applies to NSPS new and reconstructed sources.

B. Does this action apply to me?

Categories and entities potentially regulated by this final rule include:

TABLE 2—INDUSTRIAL SOURCE CATEGORIES AFFECTED BY THIS NESHAP AND NSPS FINAL ACTION

Category	NAICS code [a]	Examples of regulated entities
Industry	327310	Portland cement manufacturing plants.
Federal government		Not affected.
State/local/tribal government		Portland cement manufacturing plants.

[a] North American Industry Classification System.

Table 2 of this preamble 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 will be regulated by this action, you should examine the applicability criteria in 40 CFR 60.60 (subpart F) or in 40 CFR 63.1340 (subpart LLL). If you have any questions regarding the applicability of this final action to a particular entity, contact the appropriate person listed in the preceding **FOR FURTHER INFORMATION CONTACT** section.

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

In addition to being available in the docket, an electronic copy of this final action will also be available on the World Wide Web (WWW) through the EPA's Technology Transfer Network (TTN). Following signature by the EPA Administrator, a copy of this final action will be posted on the TTN's policy and guidance page for newly proposed or promulgated rules at the following address: *http://www.epa.gov/ttn/oarpg.* The TTN provides information and technology exchange in various areas of air pollution control. In addition, more information can be obtained at the following address: *http://www.epa.gov/airquality/cement.*

D. Judicial Review

Under section 307(b)(1) of the CAA, judicial review of this final action is available only by filing a petition for review in the court by April 13, 2013. Under section 307(b)(2) of the CAA, the requirements established by the final rule may not be challenged separately in any civil or criminal proceedings brought by the EPA to enforce the requirements.

Section 307(d)(7)(B) of the CAA further provides that "[o]nly an objection to a rule or procedure which was raised with reasonable specificity during the period for public comment (including any public hearing) may be raised during judicial review." This section also provides a mechanism for the EPA to convene a proceeding for reconsideration, "[i]f the person raising an objection can demonstrate to EPA that it was impracticable to raise such objection within [the period for public comment] or if the grounds for such objection arose after the period for public comment (but within the time specified for judicial review) and if such objection is of central relevance to the outcome of the rule." Any person seeking to make such a demonstration to us should submit a Petition for Reconsideration to the Office of the Administrator, U.S. EPA, Room 3000,

Ariel Rios Building, 1200 Pennsylvania Ave. NW., Washington, DC 20460, with a copy to both the person(s) listed in the preceding **FOR FURTHER INFORMATION CONTACT** section and the Associate General Counsel for the Air and Radiation Law Office, Office of General Counsel (Mail Code 2344A), U.S. EPA, 1200 Pennsylvania Ave. NW., Washington, DC 20460.

II. Background Information

A. What is the statutory authority for these amendments?

Section 112 of the CAA establishes a regulatory process to address emissions of HAP from stationary sources. After the EPA has identified categories of sources emitting one or more of the HAP listed in section 112(b) of the CAA, section 112(d) requires us to promulgate NESHAP for those sources. For ''major sources'' that emit or have the potential to emit 10 tons per year (tpy) or more of a single HAP or 25 tpy or more of a combination of HAP, these technology-based standards must reflect the maximum reductions of HAP achievable (after considering cost, energy requirements and non-air quality health and environmental impacts) and are commonly referred to as maximum achievable control technology (MACT) standards.

The statute specifies certain minimum stringency requirements for MACT standards, which are referred to as ''floor'' requirements. See CAA section 112(d)(3). Specifically, for new sources, the MACT floor cannot be less stringent than the emission control that is achieved in practice by the best controlled similar source. The MACT standards for existing sources can be less stringent than standards for new sources, but they cannot be less stringent than the average emission limitation achieved by the best-performing 12 percent of existing sources (for which the Administrator has emissions information) in the category or subcategory (or the best-performing five sources for categories or subcategories with fewer than 30 sources).

In developing MACT, we must also consider control options that are more stringent than the floor. We may establish standards more stringent than the floor based on the consideration of the cost of achieving the emissions reductions, any non-air quality health and environmental impacts, and energy requirements. See CAA section 112(d)(2).

Under section 112(i)(3)(A), compliance dates for existing sources shall ''be as expeditiou[s] as practicable'', but in no event later than 3 years after the date of publication of the final rule in the **Federal Register**. The EPA may set a revised compliance date of a MACT standard when amending that standard, see *NRDC* v. *EPA*, 489 F. 3d 1364, 1373–74 (D.C. Cir. 2007), but any such amended compliance date must still establish ''compliance as expeditiously as practicable.''

Section 111(b) requires the EPA to set standards for emissions that ''reflect the degree of emission limitation achievable through the application of the best system of emission reduction.'' See CAA section 111(a)(1). In contrast to the NESHAP floor setting process, NSPS requires the EPA to take into account the ''cost of achieving'' emissions reductions, as well as health, environmental, and energy considerations. *Id.*

B. What actions preceded this final rule?

The history of this final rule, commencing with the 1999 standards and proceeding through the amendments issued in September 2009, is set out in detail in 75 FR 54970 (Sept 9, 2010). The Portland Cement Association (PCA) and several cement companies filed petitions for reconsideration of aspects of those amendments (copies of the petitions are in the Portland Cement Reconsideration docket, EPA–HQ–OAR–2011–0817). On May 17, 2011, the EPA granted reconsideration of various issues, and denied the petitions to reconsider as to the remaining issues. See 76 FR 28318 (May 17, 2011). On December 9, 2011, the D.C. Circuit issued an opinion upholding the NESHAP itself (as well as the section 111 NSPS), but finding that the EPA had arbitrarily failed to grant reconsideration to consider the effect of the EPA's NHSM rule on the standards (76 FR 15456 (March 21, 2011)), The NHSM rule had the effect of reclassifying some cement kilns as commercial and solid waste incinerators. See *Portland Cement Ass'n* v. *EPA*, 665 F. 3d 177, 186–189 (D.C. Cir. 2011). The court did not stay any of the numerical emission standards, but did stay the work practice standards for open clinker storage piles pending the conclusion of the reconsideration process. See 665 F. 3d at 194.

In this action, the EPA is responding to the court's remand. For existing sources, the EPA had done so by removing all kilns classified as CISWI units from the data used to establish the 2010 NESHAP standards. The EPA then recalculated each of the floors based on this dataset (the 2010 dataset minus CISWI units) and made beyond-the-floor determinations based on the recalculated floors. The EPA believes that this approach is properly responsive to the court's remand. See 665 F. 3d at 188 where the court referred favorably to this type of recalculation. For new sources, EPA used the same data as used to establish the 2010 floors—namely the performance of the best controlled similar sources as required by section 112(d)(3).

III. Summary of Final Amendments to Subpart LLL and Subpart F

As discussed in the preamble of the proposed rule, 77 FR 42368, in this final action the EPA is finalizing several amendments to Subpart LLL and Subpart F. These amendments are summarized below.

A. Reconsideration of Standards

As noted above, EPA has responded to the action of the DC Circuit by removing all CISWI cement kilns from the database used to establish the existing source standards, and recalculating existing source floors and standards from that revised database. As described in the preamble of the proposal, the EPA had determined based on the final NHSM rule that there are 24 cement kilns which combust solid waste. 77 FR 42372. During the comment period, one company provided reliable information in its comments regarding the materials it processes indicating that one of these kilns is, in fact, a cement kiln (meaning that the EPA had properly classified it as a cement kiln in the 2010 rulemaking).[1] After reviewing the information provided, the EPA agrees that this source should not be classified as a CISWI kiln and, therefore, should not be removed from the Portland cement kiln database. We received no other comments concerning the identification of cement kilns and CISWI units. There are thus now 23 kilns identified as combusting solid waste and therefore classified as CISWI units. As directed by the Court's decision, we removed these 23 kilns from the database and recalculated the floors. This calculation resulted in the same floors as proposed in the July 2012 proposal.

Consistent with this analysis, the EPA is finalizing amendments to the emission standards as follows:

[1] The company burns dried biosolids as a fuel which are not classified as solid wastes. Refer to the Docket, No. EPA–HQ–OAR–2011–0817–0482.

1. PM Emission Standards

The EPA is revising several provisions of the emission standards for PM as follows:

- Changing the compliance basis for the PM standards from continuous monitoring with a PM CEMS to a manual three run stack test, amending the level and averaging time of the standard, and requiring a continuous parametric monitoring system using a CPMS. As a consequence, the EPA is also:
- Amending PM standards under the NESHAP for existing sources to 0.07 lb/ton clinker based on manual stack testing, and 0.02 lb/ton clinker for new and reconstructed sources based on manual stack testing;
- Amending PM standards under the NSPS for modified sources to 0.07 lb/ton clinker based on manual stack testing and 0.02 lb/ton clinker for new and reconstructed sources likewise based on manual stack testing;
- Requiring that sources establish a site-specific parametric operating limit for PM, and requiring that the parametric limit be continuously monitored using a PM CPMS;
- Requiring that sources retest once a year to reset the PM CPMS operating limit;
- Adding a provision that, if a source exceeds that site-specific parametric operating limit, it must conduct corrective action including performing a Method 5 or 5I performance test within 45 days; in addition, if the source exceeds that parametric limit four times in a calendar year, the source is presumed to be in violation of the PM emissions standard itself, subject to rebuttal by the source.

2. Mercury Standard

As proposed, the EPA is establishing a standard for mercury of 55 pounds per million (lb/MM) tons clinker for existing sources and is not changing the emission standard (21 lb/MM tons clinker) for new sources. The emission standard for existing sources is the same as the 2010 standard but is a beyond the floor standard.

3. Other Emissions Standards

As the Court requested, the EPA removed the CISWI units from the database and re-calculated the standards for THC and HCl. The standards remain the same as they were in the final 2010 rule. See also 76 FR 21149, 21152, and 21154 explaining why beyond the floor standards for THC and HCl are not justified. The 2010 rules provide an alternative to the THC standard whereby sources can meet a limit for non-dioxin organic HAP by measuring those HAP directly rather than meeting the standard for THC (a surrogate for non-dioxin organic HAP). As proposed, the EPA is changing the level of the alternative non-dioxin organic HAP standard from 9 ppm to 12 ppm. Table 3 summarizes the Final Existing and New Source Standards

TABLE 3—EXISTING AND NEW SOURCE STANDARDS [a]

Pollutant	Existing source standard	New source standard
Mercury	55 lb/MM tons clinker	21 lb/MM tons clinker.
THC	24 ppmvd	24 ppmvd.
PM	0.07 lb/ton clinker (3-run test average)	0.02 lb/ton clinker (3-run test average).
HCl	3 ppmvd	3 ppmvd.
Organic HAP [b]	12 ppmvd	12 ppmvd.

[a] Standards for mercury and THC are based on a 30-day rolling average. The standard for PM is based on a three-run test. If using a CEMS to determine compliance with the HCl standard, the floor is also a 30-day rolling average.
[b] If the source opts to comply with the THC emission limit, this standard does not apply.

B. Continuously Monitored Parameters for Alternative Organic HAP Standard (With THC Monitoring Parameter)

In addition to amending the level of the alternative oHAP standard (i.e., the standard whereby sources meet a standard for oHAP rather than for THC), the EPA is amending the provisions for the site-specific THC operating parameter for that alternative standard (where THC is a site-specific parameter monitored continuously to show compliance with the oHAP standard). The THC operating parameter is established based on THC levels measured during the successful stack test where oHAP are measured directly to demonstrate compliance. As amended, if compliance source testing of oHAP averages a value that is 75 percent or less of the emission limit for oHAP, the facility is allowed to establish a THC parametric operating level corresponding to 75 percent of the oHAP emission limit. We are adopting this provision to avoid penalizing lower-emitting sources by burdening them with the most stringent parametric operating levels. The EPA is adopting a similar provision for continuous PM parametric monitoring, for the same reason (see Section IV.A below). Sources which show oHAP emissions in compliance, but greater than 75 percent of the standard, must establish the average THC concentration measured during the 3-hour organic HAP test and use that as the site-specific THC operating level. Thus, the parametric monitoring level for THC will be the level corresponding to oHAP levels of 75 percent of the standard or the THC level of the oHAP performance test, whichever is higher.[2] Compliance with the oHAP standard will be shown as a ratio of three test runs during mill-on conditions and three test runs during mill-off conditions, with the percentage of operating time spent in each condition determining the ratio. The parametric operating level will be set according to average THC values measured during these same test runs, or to the default value of 75 percent of the standard, as just explained. In addition, the EPA will allow facilities to extend the testing time of the oHAP performance test if they believe extended testing is required to adequately capture THC variability over time. This final rule further requires that the stack test for oHAP be repeated every 30 months to establish a new site-specific THC parameter.

C. Allowing Sources With Dry Caustic Scrubbers To Comply With HCl Standard Using Performance Tests

The 2010 rule allows sources equipped with wet scrubbers to comply with the HCl standard by means of periodic performance tests rather than with continuous monitoring of HCl with a CEMS. Sources electing to comply by means of stack tests must establish continuously monitored parameters including liquid flow rate, pressure, and pH. Under this final rule, kilns with dry scrubbers may also demonstrate

[2] If a source believes that monitoring non-methane THC rather than total THC is a more reliable indicator of its oHAP emissions, it can submit an alternative monitoring request pursuant to the requirements of 40 CFR 63.8(f).

compliance with the HCl emissions limit by means of an initial and periodic stack test rather than with continuous compliance monitoring with an HCl CEMS. If a kiln equipped with a dry scrubber chooses this alternative, this final rule requires that the sorbent injection rate used during a successful performance test be recorded and then continuously monitored to show that the injection rate remains at or above the rate used during the performance test.

Where either wet or dry scrubbers are used, owners and operators may also establish sulfur dioxide (SO_2) as an operating parameter, rather than, for example, sorbent injection rate, liquid injection rate or pressure drop. If the owner or operator of a scrubber-equipped kiln makes this choice, it must establish the SO_2 operating limit equal to the average of the HCl levels recorded during the HCl performance test, and meet that operating limit on a 30 day rolling average basis. If a source exceeds any established parameter level, it must retest for HCl in order to verify compliance with the HCl emissions standard and must verify or re-establish the parametric monitoring levels as well.

At a minimum, a repeat performance test to confirm compliance with the HCl emissions limit is required every 30 months.

D. Alternative PM Limit

The 2010 final rule established an alternative PM limit to accommodate situations where kilns combine exhaust gas from various operations. 77 FR 42382. The equation establishing the alternative limit contained certain technical errors which the EPA proposed to correct. As proposed, this final rule revises the alternative PM equation so that it includes exhaust gas flows from all sources that would potentially be combined, including exhausts from the kiln, the alkali bypass, the coal mill, and the clinker cooler, for an existing kiln. The EPA is thus finalizing the following equation:

$$PM_{alt} = 0.0060 \times 1.65 \times (Q_k + Q_c + Q_{ab} + Q_{cm})/(7000)$$

Where:

PM_{alt} = The alternative PM emission limit for commingled sources.

0.0060 = The PM exhaust concentration (grains per dry standard cubic feet (gr/dscf)) equivalent to 0.07 lb per ton clinker where clinker cooler and kiln exhaust gas are not combined.

1.65 = The conversion factor of lb feed per lb clinker.

Q_k = The exhaust flow of the kiln (dscf/ton feed).

Q_c = The exhaust flow of the clinker cooler (dscf/ton feed).

Q_{ab} = The exhaust flow of the alkali bypass (dscf/ton feed).

Q_{cm} = The exhaust flow of the coal mill (dscf/ton feed).

7000 = The conversion factor for grains (gr) per lb.

If exhaust gases for any of the sources contained in the equation are not commingled and are exhausted through a separate stack, their value in the equation would be zero. The alternative PM equation for new sources is identical to the existing source equation except the PM exhaust concentration used in the equation is 0.002 gr/dscf, which is equivalent to the new source PM limit of 0.02 lb/ton clinker.

E. Coal Mills

The EPA discussed at length in the preamble to the proposed rule a potential regulatory regime to cover situations where a portion of the kiln exhaust is ducted to the coal mill. See 77 FR 42383–85; see also the regulatory text at 77 FR 42398, 42402–06, 42408–09. To assure that cement kilns do not exhaust untreated HAP through coal mills, and to assure accurate accounting of commingled emissions so that cement kilns are not penalized for commingling emissions where it makes sense to do so, the EPA is finalizing rules applicable to kiln/coal mill emissions for two configurations. In one, a portion of the kiln exhaust is ducted to a coal mill, and then the coal mill exhaust is commingled with remaining kiln exhaust and discharged through the main kiln stack. In the other, a portion of the kiln exhaust is routed through the coal mill and discharged through the coal mill stack.

In the case of a coal mill that receives and discharges a portion of the cement kiln exhaust, this final rule requires that the sum of the mercury, THC and HCl in the kiln exhaust diverted to the coal mill, and the kiln exhaust exhausted from the main kiln stack, must not exceed the subpart LLL emission limits for each respective HAP or HAP surrogate. The facility must document the contribution of the emissions diverted to the coal mill. For mercury, the rule allows tests to be performed downstream of the coal mill to take advantage of any mercury removal that occurs in the coal mill air pollution control device, and to avoid double counting emissions from mercury that becomes re-entrained in the coal. For THC and HCl, the rule allows tests to be performed upstream of the coal mill to avoid any THC or HCl that might be emitted by the coal. For owners and operators who believe that the impact of the testing location (upstream or downstream of the coal mill) would not result in their exceeding the kiln mercury, THC or HCl emissions limits and wish to conduct all their THC, HCl and mercury testing at a single location, this final rule allows testing either upstream or downstream of the coal mill. For sources complying with the alternate organic HAP limit, the facility would not be required to test for THC emissions, but would test for the organic HAP and add that concentration to the remaining emission points to estimate their total emissions for organic HAP.

A cement kiln that commingles emissions from its coal mill with all other kiln exhaust emissions and discharges through a single stack could simply meet the kiln emission limits. In the case of PM, the additional flow from the coal mill would be accounted for in the equation used to determine PM contributions from commingled flows. See section D above. In this configuration, the source would also have the option of monitoring and/or testing kiln exhaust gases prior to the introduction of the coal mill exhaust gas, and testing the kiln gas diverted to the coal mill. In this case this final rule requires that the sum of the mercury, THC (or organic HAP if the source chooses the alternative organic HAP limit), and HCl in the kiln exhaust diverted to the coal mill plus the kiln exhaust measured in the main kiln exhaust must not exceed the subpart LLL emission limits for each respective HAP or HAP surrogate.

The same provisions for coal mills also apply to kilns equipped with an alkali bypass. The one minor exception is that for PM, the summed PM emissions from the kiln and alkali bypass must be equal to or less than the PM limit in subpart LLL. Tests for PM from the alkali bypass must be conducted downstream of the alkali bypass air pollution control devices (APCD) to account for those emission reductions.

With regard to PM, the EPA stated at proposal that where a coal mill receives and discharges a portion of the cement kiln exhaust, the kiln owner operator would have to demonstrate compliance with the 40 CFR 60 subpart Y standard for PM. Although the subpart Y standard is numerically higher than the subpart LLL PM standard, EPA assumed that control would be to the same level because the subpart Y PM standard is predicated on use of fabric filer control technology. 77 FR 42383/2. However, a commenter pointed out accurately that this proposal contravened the basic principle EPA indicated it was adopting here of not allowing diverted kiln emissions to meet a more lenient standard than required by the NESHAP,

and further indicated that EPA had failed to show that these diverted PM emissions were controlled as required by section 112(d)(2) and (3) of the Act. EPA agrees with this comment, and accordingly is indicating in the final rule that commingled emissions in this situation would be required to meet the subpart LLL NESHAP for PM. Because coal mill stacks are controlled with fabric filters, we project that they can meet the subpart LLL numeric standard without further controls. See 77 FR 42383. Coal mill stacks will be required to meet annual PM performance testing and combine the measured emissions with PM emissions from the separated alkali stack, bypass stack, and/or main kiln as required in sections 60.62(b)(3), 63.1349 and 63.1350 of this rule.

This final rule also states that sources equipped with an alkali bypass stack or sources that exhaust kiln gases to a coal mill that exhausts through a separate stack are not required to install CEMS on these stacks. Instead of installing a CEMS, such sources may use the results of the initial and subsequent performance test to demonstrate compliance with the PM, THC, HCl and mercury emissions limits. Note that for the main kiln exhaust, the CEMS requirements remain.

We expand on these monitoring provisions below.

1. Mercury

Although mercury from the kiln stack is monitored using a CEMS, mercury emissions from the coal mill are based on a periodic performance test and use of the gas flow rate to the coal mill. Performance tests for mercury must be conducted annually unless and until the tested mercury levels are below the method detection limits for two consecutive years, after which tests may be conducted every 30 months. The performance test results must be summed with the emissions from the kiln stack to determine compliance. The coal mill exhaust mercury emissions are calculated on a mass basis using the measured mercury concentration and the coal mill exhaust gas flow. The coal mill exhaust flow is established using a continuous monitoring system (CMS), or the design maximum flow rate. Mass mercury emissions from the coal mill would be summed with the hourly mercury emissions from the kiln measured by the mercury CEMS. Hourly mercury emissions are then summed to calculate the rolling 30-day mass mercury emissions. This number is then divided by the corresponding 30 days of clinker production to determine the 30-day rolling average. This final rule provides equations for summing emissions from the coal mill with the mercury emissions from the kiln to determine continuous compliance. To see an example calculation, see Section 4 of the Portland Cement Reconsideration Technical Support Document (developed for the proposal), docket item EPA–HQ–OAR–2011–0817–0225.

2. THC and HCl

In this case, site specific kiln stack emission limits (to be continuously monitored) are to be calculated taking into consideration the volumetric exhaust gas flow rates and concentrations of all applicable effluent streams (kiln stack, coal mill and alkali bypass) for the kiln unit. In order to determine the flow rates and concentrations of THC and HCl in the coal mill and alkali bypass streams, the source must test every 30 months using the appropriate test method. For HCl, the performance test must be performed using Method 321 in Appendix A to 40 CFR Part 63. For measurement of THC, Method 25A in Appendix A–7 to 40 CFR Part 60 is required. With these data, the concentration of THC and HCl that must be monitored by the kiln CEMS in order to demonstrate compliance with the kiln MACT limit can be calculated using the equations in this final rule. As with mercury, the coal mill flow rate used to calculate the allowable main kiln stack THC and HCl concentrations can be based on a CMS, or on the maximum design flow rate. The sum of the kiln CEMS and the maximum emissions from the coal mill or alkali bypass must be at or below the subpart LLL limits for THC and HCl. See Section 4 of Portland Cement Reconsideration Technical Support Document (developed for the proposal), docket item EPA–HQ–OAR–2011–0817–0225, for an example calculation.

Also, as a result of these revisions, the EPA is revising the definition of kiln to include inline coal mills and adding a definition of inline coal mill.

F. NESHAP Compliance Date Extension for Existing Sources

This final rule establishes that the compliance date for the amended PM standard, and for the THC, mercury and HCl standards, for existing sources for kilns, clinker coolers and raw material dryers is September 9, 2015. This final rule also establishes February 12, 2014, as the compliance date for the existing open clinker storage pile work practice standards. A detailed discussion of these compliance dates can be found in Section V.D. below.

G. Section 112 Eligibility To Be a New Source

The EPA is not changing the date for new source eligibility under the NESHAP. Thus, a source that commenced construction or reconstruction after May 6, 2009, would remain subject to the section 112 new source standards. A more detailed discussion of this topic can be found below in Section V.E.

H. Other Testing and Monitoring Revisions

In this action we are finalizing the proposed corrections and clarifications to the 2010 rule including changes to: Equations for calculating rolling operating day emissions rates; procedures that include extraneous wording; and cross references and typographical errors in the rule.[3]

For sources that are required to monitor HCl emissions with a CEMS, we are revising the requirements for using HCl CEMS to define the span value for this source category, to include quality assurance measures for data collected under ''mill off'' conditions, and to clarify use of performance specification (PS) 15. This final rule also removes from the standard the oxygen correction factors for raw material dryers and makes minor, non-substantive changes to the sections and paragraphs below:

- Section 60.62(d).
- Section 60.63(b)(1)(i) and (ii), (b)(2), (f)(1), (2), (4), (5), (h)(1) and (6) through (9) (i).
- Section 60.64(b)(2).
- Section 60.66.
- Section 63.1340(b)(1) and (6) through (8).
- Section 63.1346(a) and (c) through (e).
- Section 63.1348(a)(2), (3)(i) through (iii), (a)(4)(i)(A), (a)(4)(ii) and (iv).
- Section 63.1348(b)(1)(i), (iii) and (iv).
- Section 63.1348(b)(3), (5), (6)(i), (8) and (c)(2)(iv).
- Section 63.1349(a), (b)(3), (d)(1) and (d)(2) and (e).
- Section 63.1350(d)(1)(i) and (ii), (f), (f)(2)(i) and (iii), (f)(3), (f)(4), (g)(1) and (2), (k), l(2), (m)(3), (m)(10) and (11), (o) and (p).
- Section 63.1352(b).
- Section 63.1356.
- In addition, we are adding requirements in section 63.1348(a), that

[3] We note that these changes required the agency to reprint sections of regulatory text. See e.g. 63.1348(a)(3)(i). In reprinting these passages, EPA has not reopened, reconsidered, or otherwise reevaluated the substance of these provisions but rather is only making the needed technical alteration.

a cement kiln that becomes subject to the rule after having been subject to the CISWI regulations, must meet all the initial compliance testing requirements even if they were previously subject to Subpart LLL.

I. Miscellaneous Amendments

We are also finalizing amendments to clarify various requirements in this final rule including issues of applicability, treatment of multiple sources that vent to a single stack, third party certification, definitions and use of bag leak detection systems when PM CPMS are in use.

For raw material, clinker or finished product storage bins, we have clarified that the requirements of this final rule apply only at facilities that are a major source (see section 63.1340(b)(6)) and that affected sources that are subject to subpart OOO (standards for nonmetallic mineral processing) are not subject to the requirements of subpart LLL (see section 63.1340(c)).

With regard to the NSPS, to clarify the recordkeeping and reporting requirement in section 60.65(a) to submit excess emission reports, we have added to section 60.61 of the NSPS a definition of ''excess emissions'' to mean ''with respect to this subpart, results of any required measurements outside the applicable range (e.g., emissions limitations, parametric operating limits) that is permitted by this subpart. The values of measurements will be in the same units and averaging time as the values specified in this subpart for the limitations.'' To clarify what data are used in the calculation of emissions, or used in the calculation of parametric levels that are used to demonstrate continuous compliance, we added to this section a definition of ''operating day'' to mean ''a 24-hour period beginning at 12:00 midnight during which the kiln operates at any time. For calculating rolling 30-day average emissions, an operating day does not include the hours of operation during startup or shutdown.'' The definition for ''operating day'' in section 63.1341 of the NESHAP is revised to be consistent with the above definition. We also became aware that some raw material dryers may be used to dry materials other than kiln feed and we have revised the definition of ''raw material dryer'' in recognition of that fact.

J. Standards During Periods of Startup and Shutdown

In the 2010 final NESHAP, the EPA established separate standards for periods of startup and shutdown which differ from the main standards that apply during steady state operations. In this action, based on comments received and the EPA's reconsideration of several technical issues related to startup and shutdown, the EPA is adopting work practices in place of these numerical standards. The rationale and provisions for the work practice standards are discussed in detail in section IV.C.

The EPA is also clarifying the operating conditions during which these standards apply, including a definition of ''startup'' and ''shutdown''. Under the amended definition, startup begins when the kiln's induced fan is turned on and fuel combustion is occurring in the main burner of the kiln. Startup ends when feed has been continuously fed to the kiln for at least 120 minutes or when the kiln feed rate exceeds 60 percent of the kiln design limitation rate. Shutdown begins when continuous feed to the kiln is halted and ends when continuous kiln rotation ceases.

The startup and shutdown-related changes include:

- Adding a definition of startup and shutdown in section 63.1341, as described;
- Adding section 63.1346(f) describing work practice standards to be met during periods of startup and shutdown;
- Revising section 63.1347 to require that startup and shutdown procedures be included in the facility's operation and maintenance plan;
- Adding section 63.1355(f) requiring records of each startup and shutdown including the date, time and duration and the quantity of feed and fuel added to the kiln during startup and shutdown;
- Adding section 63.1348(b)(9) requiring continuous compliance by operating all air pollution control devices during periods of startup and shutdown.

K. Reporting for Malfunctions and Affirmative Defense for Violation of Emission Standards During Malfunctions

The EPA added to the September 9, 2010, final NESHAP rule an affirmative defense to civil penalties for violations of emissions limits that are caused by malfunctions. Various environmental advocacy groups, as well as the PCA, indicated that there had been insufficient notice of this provision. The EPA agreed and granted reconsideration. See 76 FR 28325 (May 17, 2011). This action finalizes the EPA's decision to retain the affirmative defense on reconsideration.

The EPA is retaining in the final NESHAP rule an affirmative defense to civil penalties for violations of emission standards that are caused by malfunctions. See 40 CFR 63.1341 (defining ''affirmative defense'' to mean, in the context of an enforcement proceeding, a response or defense put forward by a defendant, regarding which the defendant has the burden of proof, and the merits of which are independently and objectively evaluated in a judicial or administrative proceeding). We are also revising some of the regulatory provisions that specify the elements that are necessary to establish this affirmative defense as proposed with minor changes from proposal described later in this section. The source must prove by a preponderance of the evidence that it has met all of the elements set forth in section 63.1344. (See 40 CFR 22.24). The criteria are designed in part to ensure that the affirmative defense is available only where the event that causes a violation of the emission standard meets the narrow definition of malfunction in 40 CFR 63.2 (sudden, infrequent, not reasonably preventable and not caused by poor maintenance or careless operation). For example, to successfully assert the affirmative defense, the source must prove by a preponderance of the evidence that the violation ''[w]as caused by a sudden, infrequent, and unavoidable failure of air pollution control, process equipment, or a process to operate in a normal or usual manner * * *.'' The criteria also are designed to ensure that steps are taken to correct the malfunction, to minimize emissions in accordance with section 63.1344 and to prevent future malfunctions.

Similar to actions taken in several other recent NESHAP amendments (see National Emissions Standards for Hazardous Air Pollutants From Secondary Lead Smelting, 77 FR 556, January 5, 2012, National Emission Standards for Hazardous Air Pollutant Emissions for Shipbuilding and Ship Repair (Surface Coating), and National Emission Standards for Wood Furniture Manufacturing Operations, 76 FR 72050, November 21, 2011), the EPA included an affirmative defense in the 2010 final rule and is retaining it in this rule (see section 63.1344). The affirmative defense provisions give the EPA the flexibility to both ensure that its emission standards are ''continuous'' as required by 42 U.S.C. § 7602(k), and account for unplanned upsets and thus support the reasonableness of the standard as a whole. In addition to the authority cited in support of the affirmative defense in the preamble to the proposed rule, the EPA notes that a recent court decision further supports

the EPA's authority to promulgate an affirmative defense. The United States Court of Appeals for the Fifth Circuit recently upheld the EPA's view that an affirmative defense provision is consistent with section 113(e) of the Clean Air Act. *Luminant Generation Co. LLC v. United States EPA,* 2012 U.S. App. LEXIS 21223 (5th Cir. Oct. 12, 2012) (upholding the EPA's approval of affirmative defense provisions in a CAA State Implementation Plan). As discussed in the preamble to the proposed rule (77 FR 42379), the EPA's view is that an affirmative defense to civil penalties for exceedances of applicable emission standards during periods of malfunction appropriately resolves an underlying tension inherent in many types of air regulation, to ensure continuous compliance while simultaneously recognizing that despite the most diligent of efforts, emission limits may be exceeded under circumstances beyond the control of the source. See generally, *Virginia v. Browner,* 80 F.3d 869, 878 (4th Cir. 1996) (the EPA's interpretation that resolved a tension within the CAA is reasonable). The EPA has used its section 301(a)(1) authority to issue regulations necessary to carry out the Act in a manner that appropriately balances these competing concerns.

We are promulgating revisions to the affirmative defense provisions in section 40 CFR 63.1344 as described at proposal (77 FR 42380) and making some minor additional revisions. The phrase "emission limit" was changed to "emission standards" to reflect that the affirmative defense could be applicable to certain work practice standards. The phrase, "Off-shift and overtime labor were used, to the extent practicable to make these repairs" was removed. The term "notification" to "reporting" was changed to reflect that the root cause analysis required under affirmative defense would be submitted with other periodic reporting. The term "and monitoring" was deleted because monitoring malfunctions are defined differently than malfunctions of process and control units and the affirmative defense is intended to apply to malfunctions to affected units that cause a failure to meet an emission standard. The word "however" was removed to incorporate more plain language into the regulation. The phrase "the respondent fails" was removed and replaced with "you fail" to incorporate more plain language into the regulation. The word "its" was replaced with "your" to incorporate more plain language into the regulation. The phrase "all of the" was replaced with "your" also to incorporate more plain language into the regulation. The phrase "air pollution control practice" was shortened to "good practices" to incorporate more plain language into the regulation. In addition, the written report required when asserting an affirmative defense was changed from a separate "semiannual" report to a report that is submitted with the first periodic compliance, deviation report or excess emission report due after the event.

We are finalizing the reporting and recordkeeping associated with violations due to malfunctions as described at proposal (77 FR 42388) and making some minor additional revisions as described below.

- Revising section 63.1354(b)(vii) for reporting and recordkeeping violations due to malfunctions. The phrase "failure to meet a standard" was used to replace "deviation" in the requirement to report violations of the standard. This was changed because the EPA is not finalizing a definition of deviation in this subpart and the term is not defined in the general provisions.
- Revising section 63.1354(c) for reporting a failure to meet a standard due to a malfunction. In addition, the phrase "failure to meet a standard" was used to replace "deviation" in the requirement to report violations of the standard. This was changed because the EPA is not finalizing a definition of deviation in this subpart and the term is not defined in the general provisions.
- Revising section 63.1355(f) addressing recordkeeping during startup and shutdown. The proposed recordkeeping requirement applicable to startup and shutdown assumed that a numerical emission standard was applicable during startup and shutdown. In finalizing the work practice standards in 63.1346(f) there will no longer be a numerical emission standard applicable during startup and shutdown. As such the recordkeeping requirement must change to reflect the content of the work practice standard. Records must be kept of the date, time and duration of the periods when the work practice is applicable, as well as the fuel and feed data to demonstrate compliance with the work practice standard.

L. What are the compliance dates of the standards?

During the comment period, comments were received that confirmed the need for additional compliance time, since the revised standards can result in different compliance strategies relative to the 2010 final rule. Thus, as proposed, this final rule establishes the compliance date for the amended existing source standards including standards for PM, mercury, HCl and THC to be September 9, 2015. The existing source compliance date for the requirements for open clinker storage piles is February 12, 2014. New sources which commenced construction or reconstruction after May 6, 2009, would remain subject to the new source standards and a compliance date of February 12, 2013, or startup, whichever is later.

M. Open Clinker Storage Piles

The EPA has added work practice requirements for open clinker storage piles that will reduce fugitive dust emissions from these sources. This final rule also contains a definition of open clinker storage piles and requires that a source's operation and maintenance plan include the steps the facility will take to minimize fugitive dust emissions from open clinker storage piles. A detailed discussion of these requirements can be found in section V.C below.

IV. Summary of Major Changes Since Proposal

A. PM Parametric Monitoring

Changes to PM Parametric Monitoring. The EPA proposed the use of PM CPMS for continuous monitoring of PM emissions as a 30-day rolling average established by identifying the average PM CPMS response corresponding to the highest 1-hour PM compliance test. Failure to meet this 30-day rolling average would result in retesting, and more than four exceedances from the parametric limit in a year would be presumed (subject to possibility of rebuttal by the source) to be a violation of the emission standard itself. See 77 FR 42377. Industry commented that this requirement would trigger unnecessary retests for many facilities, especially for the lower-emitting sources. The issue of increased compliance burden falling on the lower emitting sources is legitimate. Sources with especially low PM limits in their performance test would be most at risk of exceeding a parametric limit due to a few emission spikes, even though they would still be operating well under the actual PM compliance limit. We also received comment that the highest PM performance test run may represent, in some circumstances, a number higher than the PM emissions standard. To avoid this eventuality we have changed the final rule to require setting the PM operating limit equivalent to the average of the three PM performance tests, which constitutes the demonstration of compliance with the standard. To avoid

penalizing lower emitting facilities, the EPA has modified the way PM CPMS operating limits are established. Sources whose compliance with the PM emission standard are shown to be 75 percent or below the emission limit in the PM method 5 compliance test will set their PM parametric operating limit to be a 30-day rolling average equivalent to that 75 percent level. In a recent rule (76 FR 15736, March 21, 2011), the EPA established 75 percent of the limit as a number that allows for compliance flexibility and is simultaneously protective of the emission standard, and the same technical basis is applicable here as well. Sources whose compliance with the PM emission standard are above 75 percent of the emission limit will establish their operating limit as a 30-day rolling average equal to the average PM CPMS values recorded during the PM compliance test. It should be noted that this provision affects the allowable level of the parametric limit, but does not change the PM emission limit that must be met.

B. Scaling for Continuous Parametric Monitoring of THC for Alternative OHAP Standard

As explained in section III.B above, the EPA is adopting a scaling approach for parametric monitoring of THC under the alternative organic HAP standard which is conceptually similar to the one just discussed for parametric monitoring of PM. This provision affects the allowable level of the THC parametric limit, but does not change the oHAP emission limit that must be met.

The EPA proposed the use of THC monitoring in conjunction with organic HAP compliance testing to determine a parametric operating limit option for monitoring continuous compliance with the alternative organic HAP standard. In the proposed rule the organic HAP parametric operating limit was established by correlating the highest of three organic HAP test results with the corresponding average THC concentration recorded by a parametric THC monitor. Industry commented that this requirement would trigger unnecessary retests for many facilities, especially for the best performing sources. Not wishing to penalize those sources showing good performance, and simultaneously wanting to be protective of the emission standard, the EPA is changing the way parametric THC operating levels are established. Sources whose compliance with the organic HAP emission standard are shown to be below 75 percent of the emission limit will set their operating limit to be a 30-day rolling average equivalent to that 75 percent level. Sources whose compliance with the organic HAP emission standard are at or above 75 percent of the emission limit will establish their operating limit as a 30-day rolling average equal to the average parametric THC values recorded during the organic HAP compliance test. Sources with an in-line kiln/raw mill will use the fraction of time the raw mill is on and the fraction of time that the raw mill is off, and calculate this limit as a weighted average of the THC levels measured during raw mill on and raw mill off testing.

C. Work Practice Standard in Lieu of Numerical Emissions Limits for Periods of Startup and Shutdown

Under section 112(h) of the Act, the EPA may adopt a work practice standard in lieu of a numerical emission standard only if it is ''not feasible in the judgment of the Administrator to prescribe or enforce an emission standard for control of a hazardous air pollutant''. This phrase is defined in the Act to apply to any situation ''in which the Administrator determines that * * * the application of measurement methodology to a particular class of sources is not practicable due to technological and economic limitations.'' CAA section 112(h)(1) and (2). In adopting numerical limits for startup and shutdown in the 2010 final NESHAP, the EPA rejected comments that it should adopt work practices as a standard during startup and shutdown. This was largely because the commenters had not addressed the issue of whether the requirements of section 112(h) had been met. See docket item EPA–HQ–OAR–2002–0051–3464, pp. 183–84. The EPA later denied petitions to reconsider this issue on the grounds that the agency had already provided ample opportunity for comment on the issue, which petitioners had used. See 76 FR at 28323. The DC Circuit dismissed all challenges to the startup and shutdown provisions in the NESHAP (665 F 3d at 189). The EPA granted reconsideration on several technical issues related to startup and shutdown—specifically, monitoring of mercury and PM during startup and shutdown and having an HCl limit of zero for kilns not equipped with CEMS (see 76 FR at 28325), but these issues are no longer relevant based on the approach adopted in this final rule.

In the proposed reconsideration rule, the EPA proposed to retain the numerical standards, but to use recordkeeping rather than measurements to document compliance with the numerical standard. 77 FR 42382–83. EPA further solicited comment ''on whether the numeric standards during startup and shutdown should be amended to provide work practices'', and suggested what potential work practices might be. *Id.* at 42383. Some commenters supported retention of numerical standards, stating that nothing in the record supports a decision by the EPA that numeric standards are not feasible to measure. However, these commenters provided no supporting technical data. We also received comments opposing numeric limits and supporting work practices in their stead. Commenters stated that any numeric limit should be based on actual data gathered during startup and shutdown, which the proposed limits are not, and that measurement of emissions during startup and shutdown poses significant technical problems, mainly based on CEMS calibration issues, and the duration of startups and shutdowns.

Industry has presented information specific to the cement industry to the EPA on technical issues associated with cement kilns measuring PM, mercury, THC and HCl during periods of startup and shutdown. See docket item EPA–HQ–OAR–2011–0817–0237[1] and PCA Meeting 9–15–11 monitoring presentation in the docket for this rulemaking, as well as their public comments. EPA has continued to evaluate these data. In light of all of these public comments and further evaluation of the data, the EPA has decided to establish work practice standards in lieu of numeric standards during startup and shutdown periods. The EPA is doing so because the application of measurement methodology is not practicable for technological and economic reasons. See CAA section 112(h)(2)(B).

The operation of kilns at cement manufacturing plants is different from many other sources. Kiln startups can last days, during which time fuels are switched and temperatures and moisture conditions fluctuate substantially. Also, cement kilns have two types of inputs—raw feed that is changed into clinker in the kiln, and kiln fuel. The cement kiln is sized to accommodate not just exhaust gas flow from combustion, but the gases evolved from the calcination of limestone and moisture that evaporates from the kiln feed. As a result of these factors, the difference in gas flow characteristics of a cement kiln during steady state operation and startup/shutdown is more pronounced than that for other combustion source categories. In addition, cement kilns begin introducing feed as part of the startup process which further exacerbates the transient and fluctuating nature of these

operations not only because of the impact of this feed on the exhaust gases, but because raw materials and fuels are introduced at opposite ends of the kiln, which results in countercurrent flow of the solid material in the kiln and kiln exhaust gas, increasing the turbulence, transience and fluctuating conditions. The result is that conditions change constantly when cement kilns are in startup or shutdown mode. These conditions make stack measurements, both manual and continuous, for this source category unreliable because the constant shifting in conditions prevents any stack measurement from being representative of anything but conditions at that precise moment. For that reason manual stack tests, which take place over a period of a few hours, would not be presenting accurate information, since they would not be reliably measuring conditions across the duration of the test.

There is no way to craft a testing regime to compensate for these testing issues at each kiln in a manner that can produce reliable and replicable results. Such modifications would be specific to that individual startup event—i.e. *ad hoc* and therefore not of general applicability or utility in showing compliance. Continuous measurements conducted during these periods for cement kilns are also subject to inaccuracies resulting from these rapidly changing conditions. The temperature changes of greater than one thousand degrees Fahrenheit, flue gas moisture changes greater than 20 percent, and gas flow changes over several thousand cubic feet per minute, as well as other factors such as flue gas molecular weight swings, combine to create a complex matrix of measurement variables not accounted for in a cement kiln CEMS installation. That is, CEMS for PM, HCl, Hg, and THC are not able to reliably accommodate all of these transient shifting variables when measuring cement kiln startup and shutdown emissions. As noted above, these issues are further exacerbated by the fact that cement kilns have multiple inputs (fuel and feed), and the clinker production process generates higher gas flows than would be expected based on just the fuel inputs. This fact also means that flue gas flow rates cannot be accurately calculated from fuel inputs alone.

The EPA regards situations where a measurement may yield a value which is analytically suspect, which is the case for cement kilns during startup and shutdown for the reasons just described, as being a situation where measurement is not ''technologically practicable'' within the meaning of section 112(h)(2)(B) of the Act. Unreliable measurements raise issues of practicability and of feasibility and enforceability (see section 112(h)(1)).[4]

The EPA is not finalizing its proposed approach of setting numerical emission limits for startup and shutdown and requiring that sources certify compliance with those limits by keeping certain records certifying that they used certain fuels and did not introduce feed into the kiln. Under the proposal, sources would have had to certify compliance with the standards for the various organics based on assumed combustion conditions. As pointed out persuasively in the public comments, combustion conditions during startup and shutdown are too widely varying to either reliably measure or calculate emissions because combustion conditions change widely during startup and shutdown, sources indicated that they could not certify compliance based on an assumed combustion condition. See docket item EPA–HQ–OAR–2011–0817–0506, p. 11 (''Until ideal combustion conditions can be met in the combustion chamber (adequate temperature and turbulence), the combustion process will be incomplete. While this should not impact fuel-derived hazardous air pollutants (chlorine and mercury), it will impact the emissions of organics and possibly PM''). In light of the measurement issues noted above and the fact that sources could not certify compliance under the proposed approach, the EPA is not finalizing the proposed approach of setting numerical limits for startup and shutdown and allowing sources to certify compliance with the limits by maintaining certain records.

Instead, for the reasons explained above, the EPA is establishing work practice standards to demonstrate compliance with startup and shutdown. The work practices that apply during startup and shutdown are as follows:

- During startup the kiln must initially use any one or combination of the following clean fuels: Natural gas, synthetic natural gas, propane, distillate oil, synthesis gas, and ultra-low sulfur diesel until the kiln reaches a temperature of 1200 degrees Fahrenheit.
- Combustion of the primary kiln fuel may commence once the kiln temperature reaches 1200 degrees Fahrenheit.
- All air pollution control devices must be turned on and operating prior to combusting any fuel.
- You must keep records as specified in § 63.1355 during periods of startup and shutdown.

For the purpose of identifying when the kiln is in a startup/shutdown mode and subject to work practices and when the kiln is subject to numerical emission limits, we are defining the beginning and ending of startup and shutdown. At proposal we defined startup as when the kiln's induced fan is turned on and shutdown was defined as beginning when feed to the kiln is halted. Commenters noted that a kiln may have the induced draft (ID) fan operating even when the kiln is completely shutdown, no fuel is being burned, and there is no potential for emissions. Therefore, we changed the startup definition to be when a shutdown kiln turns on the ID fan and begins firing fuel in the main burner, because this is the point where the potential for emissions to occur begins. Startup ends when feed is being continuously introduced into the kiln for at least 120 minutes or until the feed rate exceeds 60 percent of the kiln design limitation rate. We added the duration/load element to the definition of startup because during startup a kiln must begin adding feed material to achieve steady state operation. After feed is first introduced it requires up to two hours or sufficient feed to achieve 60 percent of maximum operation to achieve a representative steady-state condition. (See meeting notes, PCA November 28, 2012, in the docket for this rulemaking). Shutdown begins when continuous feed to the kiln is halted and ends when the kiln rotation ceases.

We believe these work practices, which include the requirement that all air pollution control devices be operating, will ensure that emissions during startup and shutdown will be lower than the standards that apply during steady state operations, given use of cleaner fuels, minimal raw material inputs, and operation of all control devices during these periods. See 77 FR 42382 (noting that emissions during startup and shutdown would be expected to be lower than during steady state operations for these reasons).

[4] The application of measurement methodology during cement kiln startup and shutdown would also not be ''practicable due to * * * economic limitation'' within the meaning of section 112(h)(2)(B) since it would just result in cost expended to produce analytically suspect measurements.

V. Summary of Significant Comments and Responses

A. Amendments to Existing Source and New Source Standards for PM Under CAA Sections 112(d) and 111(b)

1. Changes to Level and Averaging Time of Existing Source NESHAP

The EPA proposed to amend the existing and new source standards for PM. The floor for the existing source standards increased from 0.04 lb/ton clinker to 0.05 lb/ton clinker as a result of removing CISWI kilns from the database. See Section 8.3, Portland Cement Reconsideration Technical Support Document, June 15, 2012, Docket item EPA–HQ–OAR–2011–0817–0225; see also 77 FR 42372/3. Second, the EPA proposed to change the compliance regime for the standard from use of PM CEMS to stack testing, a consequence being that the standard would no longer be expressed as a 30-day average but rather as the average of three test runs. The EPA thus proposed to express the recalculated floor (i.e. 0.05 lb/ton clinker 30-day average resulting from the reanalysis) as .07 lb/ton of clinker (average of three test runs). The 0.07 lb/ton clinker standard expresses the recalculated floor (i.e. 0.05 lb/ton clinker) as a not-to-exceed value based on stack testing, using the Upper Prediction Limit equation to do so. See Portland Cement Reconsideration Technical Support Document, June 15, 2012, Docket item EPA–HQ–OAR–2011–0817–0225.[5]

The EPA further proposed to use CPMS for continuous parametric monitoring. This system responds to changes in PM concentration and generates a corresponding milliamp output signal. 77 FR 42376–77. The proposed PM parametric level was correlated to the highest recorded value during three test runs. A source would meet this site-specific level on a 30-day rolling average. Failure to meet this 30-day rolling average would result in retesting, and more than four deviations from the parametric level in a year would be presumed (subject to possibility of rebuttal by the source) to be a violation of the emission standard itself. See 77 FR 42377.

Our proposal to change the compliance regime from use of CEMS to stack tests reflected technical issues related to a PM CEMS' reliability with measuring the Portland cement PM standard. Specifically, the EPA discussed the reliability of measurements, obtained using PM CEMS calibrated as required by the mandated PS 11, below the level of the 2010 standard or the level of the recalculated PM floor. See 77 FR 42374–76. The EPA's judgment at proposal was that as a result of PM measurement uncertainties, "this correlation will not be technically or practically achievable for a significant number of cement kiln sources." *Id.* at 42376.

One commenter challenged the necessity of amending the standard to a stack test regime (apparently not realizing that the existing source standard also changed as a result of removing CISWI kilns from the database). First, the commenter maintained that the EPA has no authority to voluntarily change a promulgated MACT standard to make the standard less stringent, based on the language of section 112(d)(7). The commenter further maintained that the EPA had not definitively shown that PM CEMS calibrated pursuant to PS 11 could not be used to reliably measure the Portland cement PM standard. Specifically, the commenter stated that the various problems identified by the EPA at proposal are amenable to resolution by testing longer and more often, and argued that the EPA essentially admitted as much at proposal. The commenter noted that other technical problems, like the difficulty of accounting for varied particle sizes, could be resolved by using a beta gauge CEMS. The commenter dismissed the EPA's technical reservations on these issues as arbitrary speculation. The commenter also stated that PM CEMS are already in successful use by cement plants both in this country and overseas. The commenter further believed that the EPA could resolve these technical issues by amending the PM CEMS Performance Specification rather than by amending the averaging time of the PM standard and changing its compliance basis.

In response, we note first that we do not accept the commenter's legal argument based on section 112(d)(7). Section 112(d)(7) states that "[n]o other emission standard * * * under this section shall be interpreted, construed or applied to diminish or replace the requirements of a more stringent emission limitation or other applicable requirement established pursuant to section 111 of this title, part C or D of this subchapter, or other authority of this chapter or a standard issued under State authority." Although the commenter maintained that this provision unambiguously bars the EPA from amending the promulgated NESHAP to make it less stringent, we disagree. Indeed, it is hard to read the statutory language in such a way. On its face, the provision indicates that a section 112(d) standard does not supplant more stringent standards issued under some authority other than section 112(d). Nor does the commenter's interpretation make sense. It would bar the EPA from amending a section 112(d) standard that was technically deficient or incorrect. This cannot have been Congress' intent when adopting the technology-based section 112(d) MACT regime.[6] Moreover, when Congress adopted anti-backsliding provisions in the CAA, it did so explicitly. See CAA sections 172(e); 110(l); and 193. There is no such explicit language in section 112(d)(7). Thus, the EPA does not read section 112(d)(7) as precluding amendments to MACT standards which result in numerically less stringent standards, provided of course, that such standards are technically justified and otherwise consistent with the requirements of the Act.

The commenter is also mistaken in asserting that sources can simply utilize PM CEMS not correlated to PS 11. The PS 11 requirements apply to all PM CEMS used by a cement kiln. See sections 63.1349(b)(1)(A) and 1350 (b)(1) from the 2010 final rule (75 FR 55057, 55059).[7]

With regard to the technical issues raised by this commenter, the EPA explained in detail at proposal the problems of correlating PM CEMS under PS 11 at cement plants (see 77 FR 42374–42377). These obstacles are not resolvable simply by measuring more often and longer, as the commenter maintains. Extending the duration of the Method 5 test gives this reference method additional opportunity to collect more sample mass, but this is no guarantee that the time added to the test will collect enough particulate mass to resolve detection issues, especially when testing is conducted at the better performing (lower emitting) sources. Longer test runs inherently increase the variability of the PM CEMS data collected during the test, which may cause further difficulties with the

[5] One commenter inaccurately stated that the proposed rule would essentially double the PM standard. As just explained, the existing source floor (and standard) increased from 0.04 30-day average to 0.05 lb/ton clinker 30-day average as a result of removing CISWI kilns. As a not-to-exceed standard, that same level is expressed as 0.07 lb/ton clinker, the higher level reflecting the greater variability involved when basing the standard on the average of the three test runs rather than on 30 days of measurements.

[6] The commenter cites no legislative history to support its reading, nor is EPA aware of any.

[7] It also makes no sense to use PM CEMS not subject to a uniform calibration protocol. The results obtained would not be comparable.

correlation between instrument and reference method. Nor does conducting a higher number of reference method tests resolve the difficulties with PS 11 correlation created by greater uncertainty in the reference method at low levels. Put another way, more tests with high uncertainty and poor correlation do not improve the likelihood of passing PS 11 as there is no expectation of improving the mathematical relationship between the reference test and the instrument. Furthermore, PS 11 section 8.6 requires a minimum number of fifteen tests to develop a correlation curve, with no limit to the maximum number. Considering more than 15 tests when developing the correlation creates much difficulty in developing a precise mathematical relationship. Sources are allowed to discard 5 runs for any reason they wish, but must present at least 15 test runs for the correlation calculation. *Id.* As a source increases the number of test runs beyond 20, any additional runs must be included in the correlation equation and at that point the ability of a source to satisfy PS 11 becomes more hampered with every test run.

The EPA noted that special problems are posed by the size and variability of cement kiln-generated particulate. The EPA also noted that the standard light-scintillation type of PM CEMS would likely encounter higher variability for the same PM concentration, and have difficulty satisfying correlation protocols as a result. The EPA noted that beta gauge CEMS could potentially resolve at least some issues related to cement particle variability but noted further that these devices were largely untested in the cement industry, and none (so far as the EPA is aware) has successfully completed a PS 11 certification. See 77 FR 42375/3. The commenter maintains that the existence of beta gauge CEMS resolves all questions as to their reliability in the cement industry, but the EPA reiterates, as it did at proposal, that there needs to be some assurance of the reliability of that methodology to certify with PS 11 at low levels (as required by this final rule). That information does not presently exist. The commenter states that the EPA is being speculative as to potential difficulties with a different CEMS technology, but relative to Portland cement sources, it would be speculative to assume that beta gauge CEMS would successfully pass a PS 11 certification to reliably and quantifiably measure compliance with the NESHAP, especially at the very low PM levels at some of the sources in the cement source category.

The commenter also maintains that Tapered Element Oscillating Microbalance (TEOM) devices could be used in place of light scintillation PM CEMS. A TEOM is a device that uses a very thin, tapered, element vibrating at a known frequency that has a first principle relationship to the measurement of mass. Particles that impact the element also impact the harmonic vibration of the sensor which can be translated to a measurement of the particle mass. This is a more direct approach to measuring the actual mass of PM in stack gas, and has shown promise to operate very consistently at low levels in laboratory conditions. Several TEOMs are currently used for monitoring ambient PM levels at several non-cement, non-domestic industry installations. TEOMs that are capable of measuring stack gas are not currently available for sale in the U.S., though this may change in future years. Even so, with a monitor capable of more direct mass measurement of PM in stack gas, using PS 11 to certify one against Method 5 may be problematic at low PM concentrations. The EPA currently has no data to assess TEOM capabilities versus Method 5 at very low PM concentrations such as those presented by the better performing sources in this category. Were TEOM instrumentation commercially available, the EPA would need to conduct a re-evaluation of PM CEMS technology that included TEOM data to determine if this instrument could overcome the challenges posed by calibration with Method 5 at the very low PM levels emitted by some of the sources in the cement source category. As just explained, it is not speculation, but rather legitimate engineering caution that makes it appropriate not to require compliance with a rule based on an untested measurement methodology.

The commenter further maintains that rather than amend the standard to change the compliance test methodology and averaging time, the EPA should revise PS 11 instead, evidently assuming that a revision can be done rapidly. The commenter's assumption is mistaken. Performance specification development is a process that takes multiple years and involves data collection on types of technologies, field testing, comparison to reference measurement methodology, workgroup and stakeholder meetings, peer review, rule proposal and public comment period, as well as comment response and final promulgation of the Performance Specification. With the development of PA 12A for Mercury CEMS, the EPA invested a budget in excess of one million dollars to conduct technology and field studies, as well as to refine the analytical techniques and work through stakeholder concerns prior to proposal of the Performance Specification. The process from inception to final promulgation took over 5 years to complete. PS 11, at issue here, was over 3 years in development, from concept to final promulgation, and involved a budget of $250,000. Based on this past history, it is likely to result in a delay of 3 years or more were the EPA to delay promulgation of this final rule until we could undertake the process to research, propose and finalize solutions to PS 11 that may ameliorate some of the issues vis-a-vis the cement industry now present. Furthermore, such a process would not address the issues relating to measurement uncertainties using Method 5 at low PM concentration levels near its detection limit (i.e. below its practical quantitation limit of 3 mg), and so there would remain significant technological hurdles to clear before the EPA could require the use of PM CEMS in respect to this final rule.

The commenter points to PM CEMS use by European cement kilns. This is a misplaced comparison. The European calibration and certification of this instrumentation is completely different than PS 11 requirements developed by the EPA. European monitoring is certified in a laboratory environment, and calibrated on site by the instrument vendor when installed. The EPA has a long history of requiring CEMS installations in the USA to meet more rigorous calibration and performance specification certification through a series of comparisons to reference Method 5 test measurements conducted on the stack with the flue gas matrix at the facility, not in a controlled laboratory. For a PM CEMS, this would be a correlation developed with Method 5 as described in PS 11. The two certification regimes differ greatly in approach and simply adapting European certification standards to USA facilities does nothing to mitigate this difference.

In summary, the EPA has carefully considered the issue and it is our engineering judgment that the PS 11 correlation will not be technically or practically achievable for a significant number of cement kiln sources. This is due to the combination of the low emissions concentrations, PM CEMS measurement uncertainty factors, the variability in composition of cement PM, and need for extraordinarily long test runs to reduce Method 5 uncertainty to a level that provides normal measurement confidence (i.e. greater than the 3 mg practical quantitation level of Method 5), plus the

compounding uncertainties associated with source operational variability. The EPA further recognizes that these problems in developing PS 11 correlations are most likely to adversely affect the lowest emitting sources in the category and are more likely to result in violations of the rule more often for these sources than for sources operating with higher PM emissions. This result would obviously be environmentally counterproductive. We are therefore amending the standard to be based on stack testing, and expressing the standard as a not-to-exceed (i.e., stack test Method 5 or 5I) standard of 0.07 lb/ton clinker.[8]

Additional responses regarding these issues, including responses to issues raised in the comments from industry, are found in sections 3 and 4 of the Response to Comment document, which is found in the docket for this rulemaking.

2. Issues Related to Use of CPMS for Parametric Monitoring

To document continuous compliance with the Method 5 standard (i.e., parametric monitoring designed to monitor proper operation of PM controls), the EPA proposed that PM be monitored continuously using a CPMS. See 77 FR 42376–77. The parametric limit was to reflect the highest of the three method 5 test runs from the stack test, and would be averaged over 30-days. The EPA further proposed corrective action requirements in the event of exceeding the 30-day rolling average parametric limit, and a rebuttable presumption that four such exceedances in a calendar year showed a violation of the emission standard itself.

With respect to the use of CPMS technology, the EPA has recognized that PM CEMS technology cannot meet PS 11 requirements in all Portland cement installations, yet the EPA has also recognized that PM CEMS sensors are more sensitive and better at detecting small differences in PM concentration than other technologies such as opacity monitors (*http://www.epa.gov/ttn/emc/cem/pmcemsknowfinalrep.pdf*) In considering the use of PM CEMS at Portland cement facilities we find that while using PM CEMS technology for continuous quantitative measurement of PM concentration as correlated to Method 5 with PS 11 is frequently not achievable (as stated in the preceding subsection of this preamble), using the same technology for continuous qualitative measurement of PM emissions is practicable in every instance. Given the information we have that shows PM CEMS technology to be more sensitive to in-stack PM concentration differences than opacity monitors and nepheolmeters, the EPA sees a distinct advantage in using these technologies for continuous parametric PM monitoring, rather than measuring some other parameter.

In using a PM CEMS as a CPMS to conduct continuous qualitative monitoring of PM concentration in the stack, we are not interested in specific output information from the instrument (e.g. lbs/ton clinker). We only need to know that PM concentration increases or decreases. The signal output from the instrument need not be correlated to PM concentration through PS 11 trials to achieve this, but rather we can accept the native signal output from the instrument, as is, in milliamps, and track that signal to determine trends in PM emissions. In this final rule we are requiring PM CPMS instruments to employ a 4–20 milliamp output, which is a standard electronic signal output common to many CEMS.[9] With a PM CPMS the milliamp output would not represent an opacity value, but like an opacity analyzer, the milliamps would increase as PM concentration increases and decrease as PM concentration decreases. We can then monitor the milliamp signal while conducting a Method 5 performance test and correlate the average milliamp signal to the average PM concentration during the testing. This relationship is notably coarser in terms of understanding the precise PM concentration in the stack, but the instrument's sensitivity to changing PM concentration in the stack, and its changing milliamp signal output, does not deteriorate and may still be employed to qualitatively monitor PM emissions.

The EPA received numerous comments about our proposed PM CPMS parametric monitoring approach. Industry commenters maintained that sources would have to continually retest unnecessarily, since CPMS measure an increase in PM CPMS values. This increase in PM CPMS values would (or at least, could) denote a modest rise in PM emissions, but actual stack emissions of PM could still be well below the limit. The EPA recognizes this concern as creating additional burden for facilities exhibiting good control of their PM emissions (see section IV.A above), and, therefore, we have modified the process by which a source would establish and comply with their PM CPMS operating limit in this final rule. In doing so we considered scaling options for PM CPMS signals, as they correspond with PM emissions, that were proposed by industry but found the options presented were not protective enough of the emission standard. After extensive analysis (see S. Johnson, memo to docket number EPA–HQ–OAR–2011–0817, ''Establishing an Operating Limit for PM CPMS'', November 2012), we are promulgating a scaling factor of 75 percent of the emission limit as a benchmark. See section IV.A above. As in the proposed rule, every source will need to conduct an annual Method 5 test to determine compliance with the PM emissions limit, and during this testing will also monitor their PM CPMS milliamp output. Sources which emit PM less than 75 percent of their emission limit will be able to scale their PM CPMS milliamp output to determine where their PM CPMS would intersect 75 percent of their allowed PM emissions, and set their operating level at that milliamp output. This alleviates many re-testing concerns for sources that operate well below the emission limit and provides them with greater operational flexibility while still assuring continuous compliance with the PM stack emission standard. It also creates an incentive for sources to select high efficiency PM controls when sources are evaluating potential compliance strategies.

For sources whose Method 5 compliance tests place them at or above 75 percent of the emission standard, their operating level will be the average PM CPMS milliamp output during the three Method 5 test runs. This means their operating level is the milliamp output that correlates to their PM compliance determination, and not the highest average 1 hour run value that was in the proposed rule. Now that we are adopting a scaling factor, we no longer believe that it is also appropriate to establish the parametric limit based on the highest of the three runs (which moreover, could reflect a level higher than the level of the standard). Moreover, as noted below, we believe that on balance the 30 days of averaged

[8] Because the EPA believes that these same issues pertain to measurements of the section 111(b) new source performance standard for modified sources, and because further controls would be both costly and not cost effective (see section V.A.3 below), the EPA is adopting the same amendment for modified new sources under the NSPS.

[9] For example, an opacity instrument uses a series of filters to calibrate the analyzer and produce a "percent opacity" output. Twenty five percent opacity likely correlates to a milliamp value near eight milliamps, or 4 milliamps plus 25 percent of the difference between 4 and 20 milliamps (again, 4 milliamps). Fifty percent opacity would represent a signal near 12 milliamps, and so on, with 20 milliamps representing a signal of 100 percent opacity.

CPMS measurements provides ample operating cushion.

In a recent rule (76 FR 15736, March 21, 2011), the EPA established 75 percent of the limit as a number that allows for compliance flexibility and is simultaneously protective of the emission standard. In this final rule we are utilizing that value so as not to impose unintended and costly retest requirements for the lowest emitting sources and to provide for more cost effective, continuous, PM parametric monitoring across the Portland cement sector. This approach was selected from among many considered as it provides the greatest amount of flexibility while demonstrating continuous compliance for sources which are the lower emitters in the category and is also effective in holding higher emitters to the emission standard. With this parametric monitoring approach in place we expect sources to evaluate control options that provide excellent PM emissions control and provide them greater operational flexibility below the standard.

One commenter maintained that the use of a CPMS for parametric monitoring would be ''egregious'' since the milliamp output of the CPMS allowed a source to select operational parameters of tangential relation to PM emissions and would therefore not provide useful information as to proper PM control. The commenter also stated that monitoring of opacity would be preferable. An industry commenter likewise requested that continuous opacity monitors or bag leak detectors be used rather than CPMS.

The EPA does not agree with these comments. First, the milliamp output of the CPMS reliably and sensitively indicates increasing or decreasing PM concentration in the stack. Where PM controls are failing, the PM CPMS signal will indicate the increasing concentration of PM in the stack. A source will need to monitor the trend from the PM CPMS daily reading to maintain compliance with the 30-day emission standard. Indeed, the EPA has sufficient confidence that four exceedances of the CPMS continuous measurements is a presumptive violation of the emission standard itself. Moreover, the CPMS is considerably more sensitive than an opacity monitor or bag leak detector at detecting fluctuations in PM level. An opacity monitor determines the percent of a light signal that is occluded across the stack diameter. Opacity analyzers operate on a zero to 100 percent scale, meaning they are capable of registering PM that completely occludes the far stack wall from the instrument light source. This amount of PM is roughly equivalent to a complete failure of the emission control device. A properly operating control device will emit five percent opacity or less, which is barely visible to the naked eye and on the low end of the opacity monitor capability. PM emissions that increase opacity two percent at this level may well exceed the emission standard, yet they only mildly deflect the opacity monitor output. This same 2 percent opacity increase is capable of registering changes of several milliamps on a PM CPMS when operating on the scale provided in this final rule. With several decimal fractions available between each milliamp to track signal output, and three or four milliamps representing 1 percent opacity, the PM CPMS has a clear advantage in low PM concentration measurement over continuous opacity monitoring systems. Regarding baghouse leak detectors, the EPA has no information that shows them operating on the same sensitivity level as PM CPMS technology, and we do not require baghouse leak detection systems on sources where PM CPMS are in use for this reason.

Industry commenters objected to the proposal that 4 calendar year exceedances [10] from the parametric limit would be a presumptive violation of the emission standard. Again, the EPA does not agree. First, the EPA may permissibly establish such a presumption by rule, assuming there is a reasonable factual basis to do so. See *Hazardous Waste Treatment Council* v. *EPA,* 886 F. 2d 355, 367–68 (DC Cir. 1989) explaining that such presumptions can legitimately establish the elements of the agency's *prima facie* case in an enforcement action. Second, there is a reasonable basis here for the presumption that four exceedances (i.e. increases over the parametric operating limit) in a calendar year are a violation of the emission standard. The parametric monitoring limit is established as a 30-day average of the averaged test value in the performance test, or the 75th percentile value if that is higher. In either instance, the 30-day averaging feature provides significant leeway to the owner operator not to deviate from the parametric operating level since the 30 measurements will significantly dampen variability in the single measurement (average of three test runs) that produced the parametric value. See 77 FR 42377/2 and sources there cited. The EPA acknowledges that the difference was even greater between the parametric level and the emission standard in the proposed rule (which was based on the highest measured test run). The EPA believes that the 30-day averaging feature plus the 75-percent scaling feature for the lower emitting sources now provides a sufficient operating cushion. See 77 FR 42377.

3. Existing Source Beyond the Floor Determination

The EPA proposed to use the floor levels for PM as the standard, rejecting more stringent standards on the grounds of poor cost effectiveness (after considering non-air environmental impacts and energy implications of a more stringent standard as well). See 77 FR 42376. One commenter argued that the EPA should adopt a beyond the floor standard for PM, maintaining that such a standard was justified under the factors set out in section 112 (d)(2).

The EPA disagrees, and is not adopting a beyond the floor standard. After considering the cost of the emission reductions attributable to such a standard, and the associated non-air and energy impacts of such a standard, the EPA determines that the standard is not ''achievable'' within the meaning of section 112 (d)(2). Specifically, the EPA estimates that a beyond the floor standard set at the level of the original (2010 final rule) standard would only result in 138 tpy—nationwide—of PM reduction (a value not questioned by any of the commenters). See Final Portland Cement Reconsideration Technical Support Document, December 20, 2012. We further estimate that the cost of achieving this modest incremental reduction would be approximately $37 million (the estimated cost savings attributable to the amended PM standard (including savings attributable to ancillary PM controls related to collection of PM from the control of Hg, THC, and HCl). See Final Portland Cement Reconsideration Technical Support Document, December 20, 2012, included in the rule docket, EPA–HQ–OAR–2011–0817. These total costs are high compared to the small nationwide emission reductions, and the cost effectiveness of these reductions is correspondingly high: approximately $268,000 per ton of PM removed. This is significantly higher cost effectiveness for PM than the EPA has accepted in other NESHAP

[10] In the proposed rule, the EPA referred to a measurement higher than the parametric limit as a ''deviation'' and proposed a definition of deviation. See 77 FR 42398. The EPA is not including this terminology in this final rule. The term ''deviation'' is not in the Portland cement NESHAP rules (which date back to 1998), and has not proved necessary in practice. More important, the rule itself states what the consequences of measurements which exceed a parametric limit are (i.e. retesting, and in some instances, a presumptive violation of the emission standard itself), so that no further general regulatory provision (i.e. a generalized definition of 'deviation' or similar term) is necessary.

standards. See 76 FR 15704 (March 21, 2011) (rejecting $48,501 per ton of PM as not cost effective for PM emitted by CISWI energy recovery units); see also 72 FR 53814, 53826 (Sept. 20, 2007) (proposing (and later accepting) cost effectiveness of $10,000 per ton for PM as reasonable in determining Generally Available Control Technology, and noting that the EPA had viewed cost effectiveness only as high as approximately $31,000 per ton as reasonable under its Title II program for mobile sources). A beyond the floor standard at the level of the 2010 standard would also involve slightly higher energy use, although this is not a major factor in EPA's decision. EPA is therefore not adopting a beyond the floor standard for PM at the level of the 2010 standard. A standard even more stringent would likewise not be justified. See 76 FR 54988.[11]

4. New Source PM Standard Under Section 112(d)(3)

One commenter challenged the methodology the EPA used in the 2010 rulemaking to establish the new source floor and standard, maintaining that for new plants, the EPA's floors must reflect the emission level achieved by the single best performing kiln in the category, not the best performing kiln for which the EPA happens to have emissions information. See section 112(d)(3). The EPA did not reopen the methodology by which new source floors for this industry are determined. See 77 FR 42373 n. 3 ("The EPA will not consider comments challenging the data and methodology for the new source standards since these are unchanged from the 2010 rule and the EPA is not reexamining any of these issues.") In any case, if the issue is (against the EPA's view) deemed to be reopened, CAA section 112(d)(3) indicates that new source floors are to be based on "the emission control that is achieved in practice by the best controlled similar source, *as determined by the Administrator*" (emphasis supplied). This language affords considerable discretion for the agency to base the NESHAP new source floors on performance of sources for which the agency has emissions information.

B. Mercury Standard

The EPA explained at proposal that reanalysis of the mercury floor, after removing CISWI kilns, resulted in a floor of 58 lb/MM tons clinker produced—slightly higher than the previously calculated floor and standard of 55 lb/MM tons clinker produced. The EPA further proposed to adopt 55 lb/MM tons clinker produced as a beyond-the-floor standard. See 77 FR 42373. The new source standard was unchanged since the standard was based on the performance of the best performing similar source.

The EPA is adopting the standards as proposed. One commenter challenged the appropriateness of adopting a beyond-the-floor standard, not for the industry as a whole, but for itself. As to this individual plant (Ash Grove, Durkee), the commenter maintained that the cost of attaining the three additional lb/MM ton clinker produced reduction (i.e., the difference between 58 and 55 lb/MM tons clinker produced) was greater than the EPA estimated because it would require more than just additional carbon in an activated carbon injection system to achieve the incremental difference. According to the commenter, they have performed extensive testing and the addition of activated carbon per million actual cubic feet per minute of exhaust gas has little or no impact on mercury emissions. The commenter states that for plants such as Ash Grove's Durkee plant, there is no known add-on control technology at this time that will assure achievement of the standard on a continuous basis.

We note first that the commenter is somewhat over-estimating the incremental reduction of mercury actually needed. To achieve the emission standard, sources will need to operate their processes and controls so that they can achieve the average emissions level used in setting the existing source limit of 55 lb/MM ton—the so-called design level. See e.g. 77 FR 42389/3 (estimating emissions attributable to this final rule based on design levels); see also discussion of design values in section VI.B below. That level is 31.7 lb/MM ton for the standard of 55 lb/MM ton. See 75 FR 54976/3. The average for the 58 lb/MM ton is 34.1 lb/MM ton. The additional reduction needed is therefore 2.4 lb/MM tons, not 3 lb/MM tons as stated by the commenter.

As the EPA has acknowledged repeatedly, due to the high levels of mercury in their limestone, mercury emissions from the Ash Grove Durkee plant are not typical of other plants in the industry. See, e.g. 75 FR 54978–79. As a result, this plant faces a particularly great challenge in meeting the mercury standard, whether the standard is 55 or 58 lb/MM tons. Because of their unique situation, we do not believe that the difficulties this facility is having in meeting the mercury standards can be generalized to the rest of the industry. Section 112(d)(2) of the Act posits an industry-wide standard. Having said this, our cost analysis conducted for the 2009 proposal and 2010 final rule assumed that this plant would have to install multiple control systems in order to meet the limit for mercury. See Docket item EPA–HQ–OAR–2002–0051–3438. Therefore, if in this particular case the activated carbon injection (ACI) system cannot achieve the small additional reductions required, then the facility has other mercury control options available such as further dust shuttling, or treating cement kiln dust to remove mercury. Dust shuttling entails moving dust from within the kiln to other parts of the process and is considered a closed loop process, thereby not causing any waste impacts. In addition, any costs associated with dust shuttling have already been accounted for in the cost estimates the EPA has developed for this particular facility.

The commenter alluded to control performance data that it shared with the EPA. We note that the commenter has provided pilot scale data as part of the 2010 rulemaking (see Docket item EPA–HQ–OAR–2002–0051–2073), but has not provided data on the effects of increasing carbon injection on mercury emissions for a full scale facility. We note that in the electric utility industry, where there is significantly more experience with ACI, it is well established that higher carbon injection rates increase mercury removal (Sjostrom, S.; Durham, M.; Bustard, J. Martin, C.; "Activated Carbon Injection for Mercury Control: Overview", FUEL, 89, 6, 1320 (2010)). There is no data to indicate that ACI systems in the cement industry would behave differently than those in the utility industry. Given the lack of data on the efficacy of increasing carbon injection rates on mercury removal for full scale cement operations, we cannot conclude that increasing carbon injection is not a

[11] The commenter's argument that section 112 (d)(2)'s requirement that the EPA consider "the cost of achieving such emission reduction" limits the EPA to considerations of economic achievability, and not cost effectiveness, is misplaced. See *Husqvarna AB* v. *EPA*, 254 F. 3d 195, 200 (DC Cir. 2001) (cost effectiveness properly considered in evaluating cost of compliance under CAA section 213, a technology-based provision similar to section 112 (d)(2)). The commenter's further argument that the requirement in section 112 (d)(2) for standards to result in "the maximum degree of reduction in emissions of hazardous air pollutants * * * achievable" considering cost and other factors constrains the EPA's ability to consider cost-effectiveness or otherwise balance the statutory factors has likewise been rejected. See *Sierra Club* v. *EPA*, 325 F. 3d 374, 378 (DC Cir. 2003) (the EPA was left with great discretion in determining how to balance such factors when considering technology-based standards which are to result in maximum reductions achievable).

reasonable approach for increasing mercury removal efficiency.

C. Standards for Fugitive Emissions From Open Clinker Storage Piles

The EPA proposed that cement kilns control fugitive emissions from open clinker storage piles, defined at proposal as ''any clinker storage pile that is not completely enclosed in a building or structure''. These piles would be controlled through the use of work practices which minimized emissions by means of (among others) partial enclosure, damping down the pile by chemical or physical means or shielding piles from wind. These work practices were drawn from permits for existing cement kilns, and every cement kiln appears to already be utilizing some type of work practice to minimize fugitive emissions from open clinker storage piles. See 77 FR 42378. Cement kiln sources were allowed to select from among the specified work practices and choose those most suitable for its operations.

For both new and existing sources, the NESHAP is amended to require that one or more of the control measures identified in the rule be used to minimize fugitive dust emissions from open clinker storage piles. The work practices would apply to open clinker storage piles regardless of the quantity of clinker or the length of time that the clinker pile is in existence.

In addition, the owner or operator must include as part of their operations and maintenance plan (required in § 63.1347) the location of their open clinker storage piles and the fugitive dust control measures as specified in this rule that will be implemented to control fugitive dust emissions from open clinker piles. We agree with comments received that the list of allowed work practices reflects all of the available practices documented in cement kiln facility operating permits to control clinker storage pile fugitive emissions. The size, type and duration of a clinker pile may warrant different types of work practices. The final rule requires that one or more of a variety of work practices need to be employed, recognizing that the source will use the work practices that will be effective for the particular piles. Thus, the EPA has revised the list of work practices to be consistent with those listed in the proposal preamble. These are: Use of partial enclosures, using a water spray or fogging system, applying appropriate dust suppression agents, using a wind barrier and using a tarp. Commenters also requested that the EPA allow other work practices if approved by the delegated authority. Our regulations already provide procedures for sources to seek approval of alternative work practices. See section 112(h)(3) as implemented by 40 CFR 63.8(f).

Several industry commenters stated that the definition of clinker pile is problematic as proposed because it was not limited by size or duration. Commenters note that it is not uncommon for small amounts of clinker to be dropped, or to fall off a front-loader onto the ground when being moved from a kiln to a storage location or from such a location to the grinding mill. Because these are small amounts of clinker, it is also not uncommon that these small quantities of clinker will remain where they were dropped and may not be picked up or removed until the necessary manpower becomes available; in some cases this could be multiple days. Another industry commenter noted that because of the short-term duration of temporary clinker stockpiles, the use of work practices similar to those proposed for clinker storage piles is not feasible. The industry trade association suggested the following definition: ''Open clinker storage pile means an outdoor, unenclosed accumulation of clinker on the ground, which contains in excess of 50,000 tons of clinker, and is utilized for a continuous period in excess of 180 days.'' Under this suggested approach, only a clinker storage pile meeting this definition would be subject to the work practice standards.

We are not adopting this approach. We believe that the potential to emit may be different at different sites for a variety of reasons such as weather and traffic conditions. Nor did the commenter provide information indicating that open clinker storage piles of less than 50,000 tons or stored for less than 180 days are unlikely to produce fugitive emissions. Indeed, as a result of weather, traffic or other conditions, smaller piles stored for shorter periods have the evident potential to emit substantial levels of fugitive emissions. Nor is any such uniformly applicable distinction based on duration evident. Clinker piles can be temporary but be replaced by a new pile at the same (or nearby) location a few days later, with no essential difference in fugitive emissions.

Nonetheless, we believe that the commenter is correct that spills are unavoidable, and that work practices designed for non-temporary piles cannot feasibly be applied in such circumstances. The commenter is also correct that work practices used for non-temporary piles would be misapplied to temporary piles attributable to cleaning storage structures. For these reasons, the definition of ''open storage pile'' excludes these types of piles. Specifically, the definition of open clinker storage pile does not include temporary piles of clinker that are the result of accidental spillage or temporary use of outdoor storage while clinker storage buildings are being cleaned. This final rule defines ''temporary'' to mean piles that remain in place for 3 days or less from their generation (3 days accommodating weekend scheduling). This is sufficient time to either pick these spills up (the applicable work practice for these spills) or to cover them to prevent fugitive emissions.

These final amendments will result in a cost savings to the industry as compared to the 2010 rule. As a result of requiring work practices instead of enclosures, we estimate that there will be a savings of $8.25 million annually. See Final Portland Cement Reconsideration Technical Support Document, December 20, 2012, in this rulemaking docket.

D. September 9, 2015, Compliance Date for the Amended Existing Source Standards

The EPA proposed to establish September 9, 2015, as the compliance date for the amended existing source NESHAP standards. The basic reason for the proposed compliance date was that the proposed change in the PM standard made possible different compliance alternatives for all of the stack emission standards, and that it could legitimately take two years from the original compliance date to implement these new compliance strategies. See 77 FR 42385–87. Further, the amended compliance date would apply to all of the stack emission standards due to the interrelatedness of the standards: the mercury, THC and HCl standards all typically involve some element of PM generation and capture and so the controls must be integrated with PM control strategies. Id. at 42386.

The record for this final rule supports the need for the September 9, 2015 compliance date. With respect to PM control, as the EPA explained at proposal, plants now have the option of retaining electrostatic precipitators (ESP) with modification or downstream polishing baghouses, rather than replacing ESP with baghouses. Plants may also size baghouses differently (with or without incorporation of upstream or downstream polishing elements). The various types of sorbent injection strategies to control organics, mercury and HCl, are affected by the PM limits (and vice versa). Based on the facts of this record for this source

category, the type, size and aggressiveness of the controls for these HAP, as well as the PM controls, are not only interdependent but can all change as a result of the amended PM standard. In addition, the amended alternative oHAP standard affords additional compliance alternatives for control of non-dioxin organic HAP, including alternatives to use of Residual Thermal Oxidizers. See generally, Final Portland Cement Reconsideration Technical Support Document, section 3.1, December 2012, in the docket for this rulemaking.

Determining, developing, installing, testing and otherwise implementing a different comprehensive HAP control regime takes time. Specifically, plants will need to conduct engineering studies, determine the most cost-effective control strategy, seek contract bids, purchase equipment, install and test the new equipment. Below is an estimate of a timeline for a cement kiln to undertake these steps.

TIME NEEDED TO PREPARE FOR COMPLIANCE

[Docket item EPA–HQ–OAR–2011–0817–0505–A1]

Steps in preparing for compliance	Time period
New engineering study	January–April 2013.
Selection of technology providers	April–August 2013.
Technology procurement	August–December 2013.
Detailed technology design and final engineering	January–June 2014.
Equipment fabrication and permitting	June–December 2014.
Construction and tying into existing operation	January–May 2015.
Technology commissioning	June–August 2015.

One commenter, sharply opposing any change in compliance date, maintained that all of this reasoning is hypothetical and that such a consequential extension could not legitimately rest on speculation. The EPA disagrees that this analysis is speculative. First, the EPA's engineering judgment is that the changes in the PM standard and alternative oHAP standard, open up different compliance alternatives from those under the 2010 rule. The EPA has indicated what those alternatives can be, and the time needed to determine, purchase, install and test them. Comments from the affected industry are consistent with the EPA's engineering judgment as to the type of different compliance approaches now available for existing sources.

The EPA's engineering determinations as to the time needed for cement kilns to implement a different multi-HAP control strategy here are moreover consistent with the agency's long-standing analysis (i.e. analysis not specific to the cement industry) of the time needed to install multipollutant control systems. See US EPA, Engineering and Economic Factors Affecting the Installation of Control Technologies for Multipollutant Strategies, EPA–600/R–02/073, October 2002) (cited at 77 FR 42386). Therefore, the EPA estimated that it is normal for the development and implementation of new compliance measures to take between 15–27 months for single control systems, and longer for systems involving multiple controls for HAP and criteria pollutants, as is the case here.

The record to this rule also contains a survey of 92 of the 97 domestic cement kilns currently in operation. These survey results document, on a kiln by kiln basis, alternative engineering strategies now available to these kilns as a result of the amended PM standard and also documents the time each kiln estimates would be needed to carry out these new compliance strategies. See Comments of PCA, Appendix D (EPA–HQ–OAR–2011–0817–0505). For example, kiln B [12] has the option of modifying its ESP system using a hybrid ESP/baghouse filter system, or of using a cyclone upstream of the ESP. Steps needed to implement these possibilities include main stack evaluation, cooler stack testing, and evaluation, vendor/contractor selection, final design, equipment procurement and fabrication, startup and commissioning, and demonstrating compliance. The plant has already commenced some of these steps, but provides reasonable time estimates for why it would take until September 2015 to complete them. Kiln Q [13] expects to be able to retain its ESP system (whereas it could not under the 2010 final rule), but needs to resize its dust conveying system, upgrade the ESP, and utilize a larger activated carbon injection system differently from planned (since an ESP will not capture mercury as would a baghouse). Steps involved in developing and implementing a system include reviewing the structural integrity of the existing ESP, obtaining proposals on ESP upgrades, relocating an existing stack adjacent to the existing ESP, complete stack design, order equipment for ESP upgrades, order a new stack, contract construction, perform necessary construction, modify the ESP as needed, evaluate CEMS performance and conduct stack testing and make any adjustments to the integrated control system. Again, reasonable timelines for carrying out these steps are provided.

Neither the EPA nor the industry has said definitively what each kiln will do and how long it will take. Until the standards are finalized, no such definitive pronouncement is possible. However, the record is quite specific that additional control strategies are now possible; what the range of those new control strategies are; that the strategies are interrelated so that the standards for PM, organics, mercury and HCl are all implicated; and the time needed to carry out the various strategies. Thus, the commenter is mistaken that the record regarding the need for a compliance date of September 2015 is merely conjectural.

The EPA solicited comment on the possibility of a shorter extension for the stack emission standards, noting that by virtue of the 2010 final rule, the industry was not starting from scratch but could already undertake compliance steps. See 77 FR 42386/3. The survey results referred to above confirm that this is the case, since a number of plants (to their credit) indicated that they have taken preliminary steps toward compliance such as conducting stack testing, and testing various control strategies (e.g., survey results for kilns A, F and G). Nonetheless, many commenters made the evident point that this preliminary work could only go so far when there was uncertainty about

[12] For competitiveness reasons, kilns in this survey are identified by letter. The survey results are consistent with the EPA's engineering understanding and judgment, and the EPA has no reason to dispute the overall survey results (although some details may be open to question).

[13] These examples were chosen at random by the EPA from the survey information provided in the comment.

the final standard and uncertainty around which standard would determine their final control strategy. Moreover, even those plants which had begun preliminary compliance steps indicated (with specific timelines provided) that the remaining work would legitimately stretch through the summer of 2015.

This same record refutes those comments maintaining that an even longer compliance extension is needed. Not only is this inconsistent with the EPA's own estimates, but the industry survey results document that no further time is needed. See CAA section 112(i)(3)(A) (compliance with CAA section 112(d) standards to be as expeditious as practicable). Therefore, the EPA is revising the compliance date for existing sources for PM, THC, HCl, and Hg to be September 9, 2015.

However, the EPA is establishing February 12, 2014, as the compliance date for the standards for existing open clinker piles. These standards are not inter-related to the stack emission standards, and so need not be on the same timeline. The work practices we are adopting as the standards reflect practices already in place throughout the entire industry. The time needed to come into compliance consequently is to establish a reporting and recordkeeping apparatus, and in some instances to obtain approval (after appropriate demonstration) to use work practices not enumerated in the standard. The EPA estimates that these various steps should not exceed twelve months. Since section 112(i)(3)(A) requires compliance to be as expeditious as practicable, the EPA is establishing a 12 month compliance period for these standards.

A compliance date for an amended standard must still be "as expeditiou[s] as practicable" and not more than 3 years. We believe a compliance extension is appropriate where, as here, for the stack emission standards, the amended result in a compliance regime differs from the initial rule and additional time is needed to develop, install, and implement the controls needed to meet the amended standard. The EPA has shown that to be the case here, as explained above.

The Sierra Club in its comments also argued that the EPA could not change the 2013 compliance date in the 2010 final rule as a matter of law. The commenter rests this argument on CAA sections 112(d)(7) and 112(i)(3)(A). We have responded above to the argument based on section 112(d)(7). Section 112(d)(7) simply is not an anti-backsliding provision (or, at the least, does not have to be interpreted that way).

CAA Section 112(i)(3)(A) states in relevant part:

"[a]fter the effective date of any emissions standard, limitation or regulation * * * the Administrator shall establish a compliance date or dates for each category or subcategory of existing sources, which shall provide for compliance as expeditiously as practicable, but in no event later than 3 years after the effective date of such standard".

In *NRDC* v. *EPA (Plywood MACT)*, 489 F. 3d 1364, 1373–74 (D.C. Cir. 2007) the court held that "only the effective date of Section 112 emissions standards matters when determining the maximum compliance date." 489 F. 3d at 1373 (emphasis original). The EPA, therefore, lacked authority to extend the compliance date when it was only adjusting reporting terms. Id. at 1374. The opinion implies, however, that the EPA may reset the compliance date when the EPA amends the actual standard, as here. If the statute provided an absolute bar on the EPA extending an effective date, there was no reason for the court to distinguish the situation where the EPA amends some ancillary feature of the rule from the situation where the EPA amends the actual standard.[14]

The reason it makes sense for the EPA to have the authority to reestablish a compliance date when it amends a MACT standard is evident. In a technology-based regime like section 112(d), if the technology basis of the standard changes with a change of the standard, it takes time to adopt the revised controls. This result fits the statutory text.

Where the EPA has amended an existing source MACT standard, the compliance date for that amended standard must be as expeditious as practicable, and no later than 3 years from its effective date. Sierra Club argues that the original standard (the one that has been amended) must nonetheless take effect, but that standard no longer exists. It has been amended. Moreover, the result of Sierra Club's approach would force sources to install one technology and rip it out in short order to install another. Congress cannot have mandated this result. See *PCA* v. *EPA*, 655 F. 3d at 189 (staying NESHAP standards for clinker piles—that is, effectively extending their compliance date—because "the standards could likely change substantially. Thus, industry should not have to build expensive new containment structures until the standard is finally determined.")[15] [16] Moreover, in the extreme case where the initial standard was outright technically infeasible by any source (and was amended by the EPA to correct this defect), Sierra Club's reading would leave sources with literally no legitimate compliance option.[17] Technology-based standards simply do not work this way.

[14] Sierra Club maintains that because the revisions to the PM standard leave that standard nearly as stringent as the 2010 standard, all that has effectively changed is the standard's averaging time. Sierra Club likens this situation to the amendments to ancillary provisions like reporting at issue in *Plywood MACT*. This is incorrect. First, as explained in section V.A. above, the standard did increase numerically as a result of removing commercial incinerators from the database. Portland Cement Reconsideration Technical Support Document, June 15, 2012, Docket item EPA–HQ–OAR–2011–0817–0225. Second, although the amended PM standard is relatively as stringent as the 2010 standard (75 FR 54988/2 and 77 FR 42389/3), it nonetheless affords different compliance options for all of the standards, as explained above and in further detail in the Response to Comment document. The standard allows flexibility for those days when emissions increase as a result of normal operating variability, without significantly affecting the long-term average performance for PM and affords different compliance opportunities as a result. Nor does the commenter consider the amendment to the alternative oHAP standard, which amendment likewise affords new compliance opportunities.

[15] In a variant of this argument, Sierra Club maintains that in a situation where the compliance date for an initial existing source MACT standard has not yet passed and the EPA amended that standard to make it more stringent, the EPA would nonetheless leave the predecessor less stringent standard in place and require compliance with it. Although this situation has not arisen, the EPA would presumably be governed by the same principle noted by the *PCA* court: is the technology basis for the standard changing in such a way as to require more time for compliance and in a way that negates the compliance strategy of the initial rule. (Of course, if the compliance date of a standard has already occurred and a standard is later amended, that compliance date would not change retroactively.)

[16] Sierra Club maintains that *PCA* is distinguishable because it involved a standard which the EPA was compelled to change. First, the comment is factually mistaken. The EPA had granted reconsideration of the clinker pile standards but had not indicated that the standards would be amended. See 76 FR 28325/1 (May 17, 2011). Nor did the court indicate that the pile standards must change. Rather, "[b]ecause EPA will now be receiving comments for the first time, the standards *could* likely change substantially." 655 F. 3d at 189 (emphasis supplied). Thus, the court effectively reset the compliance date because of a potential future change in the rule which could result in a compliance regime which differed from that in the 2010 final rule. This is directly parallel to the situation now presented by the amended PM and alternative oHAP standards.

[17] An example is the startup and shutdown standard for HCl in the 2010 final rule. The EPA established this standard as zero on the mistaken assumption that no chlorine could be present in the kiln during there periods. See 76 FR 28325 (granting consideration on this basis). The commenter's approach would leave this technically infeasible standard and its compliance date in place without recourse.

E. Eligibility To Be a New Source Under NESHAP

CAA section 112(a)(4) states that a new source is a stationary source if ''the construction or reconstruction of which is commenced after the Administrator first proposes regulations under this section establishing an emissions standard applicable to such source.'' As we explained previously, there is some ambiguity in the language ''first proposes'' and such language could refer to different dates in different circumstances, such as the first time the Agency proposes any standards for the source category, the first time the Agency proposes standards under a particular rulemaking record for the source category, or the first time the Agency proposes a particular standard.

In the proposed reconsideration rule, the EPA proposed to retain May 6, 2009, as the date which determines new source eligibility and solicited comment on this issue. Industry commenters stated that we should change the date for determining new source status from May 9, 2009 to July 18, 2012, the date of the proposed reconsideration rule. In support, they asserted that they will not know what the final standards are until we finalize the reconsideration rule. We disagree with the commenters' suggestion and are retaining the May 6, 2009 date as the date that determines whether a source is a new source under CAA section 112(a)(4).

As we explained at proposal, it is reasonable to retain the May 6, 2009 date as the date the Agency ''first proposed'' standards for this source category. This is the date that EPA first proposed these standards under this particular rulemaking record. Today's action is a reconsideration action, and although it revises the particulate matter new source standard, it is premised on the same general rulemaking record. It is thus reasonable to view the date EPA ''first proposes'' standards to be the May 2009 date. Further, industry commenters essentially advocate an approach whereby any time the Agency changes a new source standard, in any way, on reconsideration, the new source trigger date would change. Such a result is not consistent with Congress' intent in defining the term ''new source'' in section 112(a)(4), to be the date the Agency ''first proposes'' standards. Furthermore, EPA notes that the new source standards finalized today are ones that will be met, in our view, using the same or similar control technologies as would be used to meet the standards issued in May 2010, and commenters have not disputed this conclusion. See 77 FR 42387.

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

A. What are the affected sources?

As noted in the proposed rule, the EPA estimates that by 2013 there will be 100 Portland cement manufacturing facilities located in the U.S. and Puerto Rico that are expected to be affected by this final rule, and that approximately 5 of those facilities are new greenfield facilities. All these facilities will operate 156 cement kilns and associated clinker coolers. Of these kilns, 23 are CISWI kilns. These have been removed from our data set used to establish existing source floors. Based on capacity expansion data provided by the PCA, by 2013 there will be 16 kilns and their associated clinker coolers subject to NESHAP new source emission limits for PM, mercury, HCl and THC, and 7 kilns and clinker coolers subject to the amended NSPS for nitrogen oxide and SO_2. Some of these new kilns will be built at existing facilities and some at new greenfield facilities.

B. How did the EPA evaluate the impacts of these amendments?

For these final amendments, we determined whether additional control measures, work practices and monitoring requirements would be required by cement manufacturing facilities to comply with the amended rules, incremental to the 2010 final standards (since any other comparison would result in double counting). For any additional control measure, work practice or monitoring requirement we determined the associated capital and annualized cost that would be incurred by facilities required to implement the measures. Finally, we considered the extent to which any facility in the industry would find it necessary to implement any of the additional measures in order to comply with these final amendments. Using this approach, we assessed potential impacts from the proposed revisions.

These final amendments to the 2010 rule are expected to result in lower costs for the Portland cement industry. The final amendment to the PM standard affords alternative, less costly compliance opportunities for existing sources. See section V.D above. These could be utilizing existing PM control devices rather than replacing them (for example, retaining an ESP or a smaller baghouse), or supplementing existing PM control rather than replacing it (putting polishing controls ahead of the primary PM control device, for instance). Compliance strategies for the other HAP, all of which involve some element of PM control, also may be affected. Cost savings from these alternatives could be significant. There are also potential cost savings associated with the amended oHAP alternative standard (which now may be a viable compliance alternative for some sources since issues of reliable analytic measurement have been resolved). Following proposal, industry submitted kiln specific information on likely changes in compliance strategy resulting from the proposed amendments so that we are now better able to estimate potential savings resulting from the final amendments. Based on an industry survey of 18 Portland cement facilities (20 kilns) after proposal (see Docket item EPA–HQ–OAR–2011–0817–0505, Appendix D), it appears that the amendments may have the following effects, which may result in savings in capital and annual costs associated with implementing control technologies for these pollutants:

- Regenerative thermal oxidizers (RTO) may not need to be installed due to the amended oHAP alternative.
- Carbon injection rates may be lowered or not required for THC control.
- Existing PM controls (ESP and baghouse) may not need to be replaced, but may instead be upgraded.
- Additional PM controls may not have to be implemented.
- Polishing and hybrid filter configurations may be implemented instead of total replacements.

There are also certain costs, and cost savings, associated with other provisions of the final amendments. There may be a difference in costs of stack testing for PM and use of a CPMS, rather than use of a PM CEMS. In addition, there are cost savings when changing from a PM CEMS compliance demonstration to a CPMS demonstration. For example as part of the PS 11 calibration requirements, a minimum of 15 Method 5 test runs are required to develop a correlation curve, with no limit to the maximum number of test runs. Omitting the need for these multiple test runs will save the facility a minimum of $20,000 per kiln (each Method 5 test costs $5,000). At a savings of $20,000 per kiln, nationwide savings for 133 new and existing kilns, would be $2.7 million per year. However, the CPMS is the same type of device as a PM CEMS, so the capital cost of the CPMS would not be significantly different than the CEMS device.

The final revisions to the alternative organic HAP standard (from 9 ppm to 12 ppm, reflecting the analytic method practical quantitation limit) would allow more sources to select this compliance alternative and demonstrate compliance without needing to install

very expensive and energy-intensive RTO. In addition, providing parametric monitoring flexibilities (not present in the 2010 final rule) will provide lower costs for the better-performing sources in the industry. See section IV.B above. We have quantified these savings (see Final Portland Cement Reconsideration Technical Support Document, December 20, 2012, Section 3).

The revisions to the standard for open clinker storage piles codify current fugitive dust control measures already required by most states, so no impacts are expected. These final standards would be significantly less expensive than the controls for open piles in the 2010 final rule, which required enclosures in all instances. We estimate that the savings to industry over the 2010 rule will be $8.25 million annually. See Final Portland Cement Reconsideration Technical Support Document, December 20, 2012, in this rulemaking docket.

We have estimated the additional industry cost associated with the affirmative defense to civil penalties provisions. We estimate the additional cost is $3,258 per year for the entire industry. See Supporting Statement in the docket.

One of the final revisions would allow sources that control HCl with dry scrubbers to use periodic performance testing and parametric monitoring rather than monitoring compliance with an HCl CEMS. This will provide those sources with additional flexibility in complying with the HCl standard.

The revision to the alternative PM emissions limit provisions merely recognizes that sources other than the clinker cooler may combine their exhaust with the kiln exhaust gas and corrects the equation for calculating the alternative limit. Therefore, there should be no impacts from this revision.

The amendments provide for work practices rather than numerical standards during periods of startup and shutdown. The work practice standards reflect common industry practices, so there should be no costs associated with them. There should also be substantial savings associated with the work practices.

At an annual cost of about $51,000 per year ($22,800 per Method 30B test for mercury + $8,000 per year for Method 25A test for THC + $20,000 per year for Method 321 test for HCl), the final revisions for new testing and monitoring of coal mills that use kiln exhaust gases to dry coal and exhaust through a separate stack are not expected to have significant impacts.

The revisions would make existing kilns that undergo a modification, as defined by NSPS, subject to a PM standard of 0.07 lb/ton clinker, 3-run average. There may be less costly compliance alternatives under the amended standard, similar to alternatives available under the amended existing source NESHAP for PM.

C. What are the air quality impacts?

In these final amendments, emission limits for mercury, THC and HCl are unchanged from the 2010 rule. Thus, there is no change in emissions from the 2010 rule for these HAP and HAP surrogates. The alternative HAP organic standard is being amended to 12 ppm, which is the analytic method practical quantitation limit based on the performance test method detection limit of 4 ppm. The impact on emission levels due to this change is not clear since measuring below the quantitation limit does not yield a value with enough certainty to represent the actual level. Thus, a measurement below 12 ppm could very well actually be 12 ppm or something less. For PM, the limit for existing sources changes from 0.04 lb/ton clinker 30-day average to 0.07 lb/ton clinker based on stack testing. The PM limit for new sources also changed: To 0.02 lb/ton clinker stack test from 0.01 lb/ton clinker 30-day average. The final changes in the PM standards, while not significant in absolute terms, may result in a small increase in total nationwide emissions by allowing slightly more variability, although, as noted at proposal, we estimate that design values will be essentially identical under the 2010 and this final standard. 77 FR 42389. As explained in the impacts analysis for the 2010 rule (see Docket item EPA–HQ–OAR–2002–0051–3438), emission reductions were estimated by comparing baseline emissions to the long-term average emissions of the MACT floor kilns. As a practical matter, plants operate to comply with this lower average emissions level (the so-called design level), rather than the emissions limit, so that on those days where there is normal operating variability they do not exceed the emissions limit. See 77 FR 42386–87. Under the 2010 rule, the average PM emissions from the existing floor kilns were 0.02296 lb/ton clinker. Under the amended standard, the average PM emissions of the existing floor kilns is calculated to be 0.02655 lb/ton clinker although, as noted, this difference is less than the normal analytic variability in PM measurement methods and so must be viewed as directional rather than precisely quantitative. The average emissions for new kilns did not change as we believe new sources will have to adopt identical control strategies as under the promulgated standards. We, therefore, are not estimating an emission increase from new kilns. For existing kilns, with an increase in PM emissions under this final rule of 0.00359 lb/ton clinker compared to the 2010 rule, nationwide emissions of PM would increase by 138 tons per year ($0.00359 \times 76{,}664{,}662/2000$). Thus, the EPA estimates that the main effect of this final rule for PM will be to provide flexibility for those days when emissions increase as a result of normal operating variability, but would not significantly alter long-term average performance for PM. Nonetheless, as explained in section V.D above, this change does allow for changes in compliance strategies in the form of types, sizes and sequencing of treatment trains.

Emission reductions under the 2010 rule and this final rule, in 2015, are compared in Table 4.

TABLE 4—COMPARISON OF NATIONWIDE PM EMISSIONS FROM 2010 RULE TO FINAL RULE IN 2015

	Kiln type	2010 rule	Final rule	Increment
Emissions limit (lb/ton clinker	Existing	0.04 (30-day average with a CEMS).	0.07 (3-run stack test)	NA
MACT average emissions for compliance (lb/ton clinker.	Existing	0.02296	0.02655	0.00359
2010 baseline emissions (CISWI kilns removed) (tons/yr).		11,433	11,433	NA
Nationwide emissions reduction (tons/yr)	Total	10,540	10,402	−138

One commenter noted that the compliance extension will result in two additional years of HAP emissions at pre-standard levels, noting especially the emission of PM, noting further that fine PM ($PM_{2.5}$) is causally associated with mortality and serious morbidity effects at a population level. See, e.g., 77 FR 38909 (June 29, 2012). We note first that these rules are technology-based, not risk-based, and that there are compelling reasons to amend the PM standard and to establish new compliance dates for existing sources as a result of technological limitations with the 2010 rule PM standard, and the new compliance opportunities afforded as a result of the amendment to that standard. See section V.D above. We also question the commenter's premise that all of the predicted emission reductions and benefits would accrue if the existing source CEM-based PM standards took effect in September 2013. As explained at length in section V.A above and in other comment responses, PM CEMS would not reliably measure the level of the PM standard in many instances. One cannot assume the full range of emission reductions (and consequent health benefits) would accrue in the real world if the emission measurements themselves are uncertain. Thus, in a meaningful sense, today's amendments result in a regime where the required emission reductions will be reliably measured, so that the rule's health benefits will reliably occur.

D. What are the water quality impacts?

At proposal, we believed that none of the amendments being proposed would have significant impacts on water quality and that to the extent that the revision affecting dry caustic scrubbers encourages their use, some reduction in water consumption may occur although we had no information upon which to base a quantified estimate. We received no comments questioning this assessment. Further, in reviewing the industry survey information on the impacts of the proposed changes, only 1 of the 20 kilns for which information was provided was considering the addition of a wet scrubber, although it was also evaluating a dry scrubber (see docket item EPA–HQ–OAR–2011–0817–0505, Appendix D, kiln S). Therefore, we continue to believe that these final amendments will not significantly impact water quality.

E. What are the solid waste impacts?

None of the amendments being finalized with this final rule are expected to have any solid waste impacts.[18]

F. What are the secondary impacts?

Indirect or secondary air quality impacts include impacts that will result from the increased electricity usage associated with the operation of control devices as well as water quality and solid waste impacts (which were just discussed) that will occur as a result of these amendments. Because we are finalizing revisions that slightly reduce the stringency of the existing source emission limits for PM from the promulgated 2010 limits, we project that some facilities will alter their strategy for complying with the standards for the four pollutants to achieve compliance at a lower cost than possible under the original standard. The survey results discussed in section V.D above confirm the EPA's engineering judgment. Other facilities in the survey that were not able to meet the THC limit or the alternative organic HAP limit in the 2010 rule were considering the installation of RTO. Because some of these facilities may now meet the limit without the installation of an RTO, we have estimated a reduction of 24,702 tons per year less CO_2 emissions being emitted to the atmosphere (equivalent to 2 less RTO's being installed). As a result of the organic HAP limit being revised from 9 ppm to 12 ppm, these sources responded that they now had other less costly alternatives. The additional compliance time was also cited as a factor that would gives sources the additional time they needed to consider other HAP control alternatives to RTO. As the industry survey highlights, these types of determinations will be made for each facility based on site-specific characteristics such as process type, equipment age, existing air pollution controls, raw material and fuel characteristics, economic factors and others. In general, this survey indicates that the combination of the revised limits for PM and organic HAP as well as the September 2015 compliance date will give sources the opportunity to develop less costly and less aggressive compliance strategies. We do not have enough information to quantify the impact of overall secondary impacts, (with the exception of the CO_2 reductions noted above), but we believe the impacts would in fact be reduced relative to the 2010 rule since less energy is expected to be needed for facilities that can retain and upgrade their current controls, instead of for example, installing additional controls in series.

G. What are the energy impacts?

As discussed in the preceding section, because of the final revisions to the PM emission limits, the organic HAP limits and the compliance date extension, some facilities will develop more cost effective and less energy intensive compliance strategies. For three of the facilities (five kilns) that were part of the industry survey, all five kilns required significant changes to meet the 2010 THC standard, in part because they were not pursuing the alternative organic HAP alternative standard due to analytic measurement uncertainties. See docket item EPA–HQ–OAR–2011–0817–0505, Appendix D (kilns A, C and D, and F and G). Prior to the proposed revisions, all five of the kilns were considering RTO as a control option as well as other options including catalytic ceramic filtration, a relatively new technology and as yet, not completely demonstrated technology for the cement industry. In response to the survey of what changes, if any, the facilities would make in response to the proposed revisions, all three facilities indicated that the amended organic HAP limit or the September 2015 compliance date allowed them to consider the use of less capital intensive alternatives and to continue testing alternatives for THC reduction other than the highly energy-intensive RTO for the five kilns involved. Although we cannot accurately predict for the entire industry the extent to which these site-specific compliance strategies may affect energy demands, the industry survey results indicate a trend toward less energy intensive strategies than RTO, and as noted above, we predict a reduction in CO_2 emissions due to less energy use as a result of two fewer kilns installing RTOs.

H. What are the cost impacts?

Under the cost scenario discussed above, we estimate that there could be savings of approximately $52 million associated with alternative compliance strategies for meeting amended PM standards, making corresponding adjustments in compliance strategies for the organic HAP and requiring work practice for open clinker storage piles. Table 5 summarizes the costs and emissions reductions of this final action.

[18] Although dust shuttling is likely to be one element of mercury compliance strategy, the amount of dust shuttling would not increase incremental to the 2010 final rule since the standards for new and existing sources are the same in the 2010 final rule and these amendments. Moreover, as explained in section V.B above, even with respect to the high mercury feed source, dust shuttling entails moving dust from within the kiln to other parts of the process and is considered a closed loop process, thereby not causing any waste impacts.

TABLE 5—SUMMARY OF THE COSTS AND EMISSION REDUCTIONS OF THE FINAL AMENDMENTS TO THE PORTLAND CEMENT MANUFACTURING INDUSTRY NESHAP RELATIVE TO THE 2010 RULE[a b c d e]

Proposed amendment	Annualized cost	PM emissions reduction 2010 rule	PM emissions reduction 2012 rule	Emission change tpy
Revised PM, oHAP standard	($42.2 million)[f]	10,540 tons	10,402 tons	138 increase.
Replace PM CEMS with PM CPMS	($2.7 million)	0.		
Coal Mill Testing	$1.3 million	0.		
Open clinker storage pile work practices	($8.25 million)	0.		
Total	($51.85 million).			

[a] Parentheses indicate cost savings. All costs are in 2005 dollars.
[b] We also estimate that there will be a one-time cost of $25,000 for each facility to revise their operation and maintenance plan to include procedures to minimize emissions during periods of startup and shutdown.
[c] Emissions reductions are the total once full compliance is achieved in 2015.
[d] Full compliance costs will not occur until September 9, 2015.
[e] Note emission reductions published in the 2010 rule included CISWI kilns, but the reductions in this table reflect reductions since CISWI kilns were removed from the database.
[f] Includes cost savings due to revised PM standard.

The cost information in Table 5 is in 2005 dollars at a discount rate of 7 percent. The EPA did not have sufficient information to quantify the overall change in benefits or impacts in emissions for 2013 to 2015.

With regard to the coal mill monitoring requirements in this action, sources with integral coal mills that exhaust through a separate exhaust would potentially incur a capital cost of $36,000 to install a continuous flow meter. The annualized cost of a flow meter is $11,000. Because this final rule allows the use of maximum design flow rate instead of installing flow meters, we believe that most facilities will take advantage of this and will not incur these costs. Annual testing at these coal mills for mercury, THC and HCl will cost about $51,000 ($22,800 per Method 30B test for mercury + $8,000 per year for Method 25A test for THC + $20,000 per year for Method 321 test for HCl). Using information supplied by the industry (see docket item EPA–HQ–OAR–2011–0817–0612), approximately 26 facilities would be affected by these requirements for an annual cost of $1.3 million. Costs for coal mills to meet the PM limits for this NESHAP are not included, since all equipment and monitoring are in place to meet requirements of Subpart Y and thus are not considered additional costs.

With the final change to PM CPMS instead of CEMS, it is estimated that the elimination of the PS correlation tests will result in a savings of $20,000 per kiln.

I. What are the health effects of these pollutants?

In this section, we provide a qualitative description of benefits associated with reducing exposure to $PM_{2.5}$, HCl and mercury. Controls installed to reduce HAP would also reduce ambient concentrations of $PM_{2.5}$ as a co-benefit. Reducing exposure to $PM_{2.5}$ is associated with significant human health benefits, including avoiding mortality and morbidity from cardiovascular and respiratory illnesses. Researchers have associated $PM_{2.5}$ exposure with adverse health effects in numerous toxicological, clinical and epidemiological studies (U.S. EPA, 2009).[19] When adequate data and resources are available and a regulatory impact analysis (RIA) is required, the EPA generally quantifies several health effects associated with exposure to $PM_{2.5}$ (e.g., U.S. EPA, 2011).[20] These health effects include premature mortality for adults and infants, cardiovascular morbidities such as heart attacks, hospital admissions and respiratory morbidities such as asthma attacks, acute and chronic bronchitis, hospital and emergency department visits, work loss days, restricted activity days and respiratory symptoms. Although the EPA has not quantified certain outcomes including adverse effects on birth weight, pre-term births, pulmonary function and other cardiovascular and respiratory effects, the scientific literature suggests that exposure to $PM_{2.5}$ is also associated with these impacts (U.S. EPA, 2009). $PM_{2.5}$ also increases light extinction, which is an important aspect of visibility (U.S. EPA, 2009).

HCl is a corrosive gas that can cause irritation of the mucous membranes of the nose, throat and respiratory tract. Brief exposure to 35 ppm causes throat irritation, and levels of 50 to 100 ppm are barely tolerable for 1 hour.[21] The greatest impact is on the upper respiratory tract; exposure to high concentrations can rapidly lead to swelling and spasm of the throat and suffocation. Most seriously exposed persons have immediate onset of rapid breathing, blue coloring of the skin and narrowing of the bronchioles. Exposure to HCl can lead to RADS, a chemically- or irritant-induced type of asthma. Children may be more vulnerable to corrosive agents than adults because of the relatively smaller diameter of their airways. Children may also be more vulnerable to gas exposure because of increased minute ventilation per kilograms and failure to evacuate an area promptly when exposed. HCl has not been classified for carcinogenic effects.[22]

Mercury in the environment is transformed into a more toxic form, methylmercury (MeHg). Because mercury is a persistent pollutant, MeHg accumulates in the food chain, especially the tissue of fish. When people consume these fish, they consume MeHg. In 2000, the National

[19] U.S. Environmental Protection Agency (U.S. EPA). 2009. *Integrated Science Assessment for Particulate Matter* (Final Report). EPA–600–R–08–139F. National Center for Environmental Assessment-RTP Division. Available on the Internet at *http://cfpub.epa.gov/ncea/cfm/recordisplay.cfm?deid=216546.*

[20] U.S. Environmental Protection Agency (U.S. EPA). 2011. Regulatory Impact Analysis for the Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone in 27 States; Correction of SIP Approvals for 22 States. Office of Air and Radiation, Research Triangle Park, NC. Available on the Internet at *http://www.epa.gov/airtransport/pdfs/FinalRIA.pdf.*

[21] Agency for Toxic Substances and Disease Registry (ATSDR). Medical Management Guidelines for Hydrogen Chloride. Atlanta, GA: U.S. Department of Health and Human Services. Available online at *http://www.atsdr.cdc.gov/mmg/mmg.asp?id=758&tid=147#bookmark02.*

[22] U.S. Environmental Protection Agency (U.S. EPA). 1995. Integrated Risk Information System File of Hydrogen Chloride. Research and Development, National Center for Environmental Assessment, Washington, DC. This material is available electronically at *http://www.epa.gov/iris/subst/0396.htm.*

Academy of Science (NAS) Study was issued which provides a thorough review of the effects of MeHg on human health (National Research Council (NRC), 2000).[23] Many of the peer-reviewed articles cited in this section are publications originally cited in the MeHg Study. In addition, the EPA has conducted literature searches to obtain other related and more recent publications to complement the material summarized by the NRC in 2000.

In its review of the literature, the NAS found neurodevelopmental effects to be the most sensitive and best documented endpoints and appropriate for establishing an oral reference dose (RfD) (NRC, 2000); in particular NAS supported the use of results from neurobehavioral or neuropsychological tests. The NAS report noted that studies in animals reported sensory effects as well as effects on brain development and memory functions and support the conclusions based on epidemiology studies. The NAS noted that their recommended endpoints for an RfD are associated with the ability of children to learn and to succeed in school. They concluded the following: ''The population at highest risk is the children of women who consumed large amounts of fish and seafood during pregnancy. The committee concludes that the risk to that population is likely to be sufficient to result in an increase in the number of children who have to struggle to keep up in school.''

The NAS summarized data on cardiovascular effects available up to 2000. Based on these and other studies, the NRC concluded that ''Although the data base is not as extensive for cardiovascular effects as it is for other end points (i.e. neurologic effects) the cardiovascular system appears to be a target for MeHg toxicity in humans and animals.'' The NRC also stated that ''additional studies are needed to better characterize the effect of methylmercury exposure on blood pressure and cardiovascular function at various stages of life.''

Additional cardiovascular studies have been published since 2000. The EPA did not to develop a quantitative dose-response assessment for cardiovascular effects associated with MeHg exposures, as there is no consensus among scientists on the dose-response functions for these effects. In addition, there is inconsistency among available studies as to the association between MeHg exposure and various cardiovascular system effects. The pharmacokinetics of some of the exposure measures (such as toenail mercury levels) are not well understood. The studies have not yet received the review and scrutiny of the more well-established neurotoxicity data base.

The Mercury Study[24] noted that MeHg is not a potent mutagen but is capable of causing chromosomal damage in a number of experimental systems. The NAS concluded that evidence that human exposure to MeHg caused genetic damage is inconclusive; they note that some earlier studies showing chromosomal damage in lymphocytes may not have controlled sufficiently for potential confounders. One study of adults living in the Tapajós River region in Brazil (Amorim et al., 2000) reported a direct relationship between MeHg concentration in hair and DNA damage in lymphocytes; as well as effects on chromosomes.[25] Long-term MeHg exposures in this population were believed to occur through consumption of fish, suggesting that genotoxic effects (largely chromosomal aberrations) may result from dietary, chronic MeHg exposures similar to and above those seen in the Faroes and Seychelles populations.

Although exposure to some forms of mercury can result in a decrease in immune activity or an autoimmune response (ATSDR, 1999), evidence for immunotoxic effects of MeHg is limited (NRC, 2000).[26]

Based on limited human and animal data, MeHg is classified as a ''possible'' human carcinogen by the International Agency for Research on Cancer (IARC, 1994) and in Integrated Risk Information System (IRIS) (U.S. EPA, 2002).[27][28] The existing evidence supporting the possibility of carcinogenic effects in humans from low-dose chronic exposures is tenuous. Multiple human epidemiological studies have found no significant association between mercury exposure and overall cancer incidence, although a few studies have shown an association between mercury exposure and specific types of cancer incidence (e.g., acute leukemia and liver cancer) (NRC, 2000).

There is also some evidence of reproductive and renal toxicity in humans from MeHg exposure. However, overall, human data regarding reproductive, renal and hematological toxicity from MeHg are very limited and are based on either studies of the two high-dose poisoning episodes in Iraq and Japan or animal data, rather than epidemiological studies of chronic exposures at the levels of interest in this analysis.

VII. Statutory and Executive Order Reviews

A. Executive Order 12866: Regulatory Planning and Review and Executive Order 13563: Improving Regulation and Regulatory Review

Under Executive Order 12866 (58 FR 51735, October 4, 1993), this action is a ''significant regulatory action'' because it raises novel legal or policy issues. Accordingly, the EPA submitted this action to the Office of Management and Budget (OMB) for review under Executive Orders 12866 and 13563 (76 3821, January 21, 2011) and any changes made in response to OMB recommendations have been documented in the docket for this action. An RIA was prepared for the September 2010 final rule and can be found at: *http://www.epa.gov/ttn/ecas/regdata/RIAs/portlandcementfinalria.pdf. http://www.epa.gov/ttn/ecas/regdata/RIAs/portlandcementfinalria.pdf.*

B. Paperwork Reduction Act

The information collection requirements in this final rule have been submitted for approval to the OMB under the *Paperwork Reduction Act,* 44 U.S.C. 3501, *et seq.*

The Information Collection Request (ICR) document prepared by the EPA has been assigned the EPA ICR number 1801.11 for the NESHAP; there are no additional recordkeeping and reporting requirements for the NSPS. The information requirements are based on notification, recordkeeping and reporting requirements in the NESHAP

[23] National Research Council (NRC). 2000. *Toxicological Effects of Methylmercury.* Washington, DC: National Academies Press.

[24] U.S. Environmental Protection Agency (U.S. EPA). 1997. *Mercury Study Report to Congress,* EPA–HQ–OAR–2009–0234–3054. December. Available on the Internet at *http://www.epa.gov/hg/report.htm.*

[25] Amorim, M.I.M., D. Mergler, M.O. Bahia, H. Dubeau, D. Miranda, J. Lebel, R.R. Burbano, and M. Lucotte. 2000. Cytogenetic damage related to low levels of methyl mercury contamination in the Brazilian Amazon. An. Acad. Bras. Science. 72(4): 497–507.

[26] Agency for Toxic Substances and Disease Registry (ATSDR). 1999. Toxicological Profile for Mercury. U.S. Department of Health and Human Services, Public Health Service, Atlanta, GA.

[27] U.S. Environmental Protection Agency (EPA). 2002. Integrated Risk Information System (IRIS) on Methylmercury. National Center for Environmental Assessment. Office of Research and Development. Available online at *http://www.epa.gov/iris/subst/0073.htm.*

[28] International Agency for Research on Cancer (IARC). 1994. IARC Monographs on the Evaluation of Carcinogenic Risks to Humans and their Supplements: Beryllium, Cadmium, Mercury, and Exposures in the Glass Manufacturing Industry. Vol. 58. Jalili, H.A., and A.H. Abbasi. 1961. Poisoning by ethyl mercury toluene sulphonanilide. Br. J. Indust. Med. 18(Oct.):303–308 (as cited in NRC 2000).

General Provisions (40 CFR part 63, subpart A), which are mandatory for all operators subject to national emissions standards. These recordkeeping and reporting requirements are specifically authorized by CAA section 114 (42 U.S.C. 7414). All information submitted to the EPA pursuant to the recordkeeping and reporting requirements for which a claim of confidentiality is made is safeguarded according to agency policies set forth in 40 CFR part 2, subpart B.

We are finalizing new paperwork requirements for the Portland Cement Manufacturing source category in the form of a requirement to incorporate work practices for periods of startup and shutdown and fugitive dust control measures for clinker piles into their existing operations and maintenance plan.

This final rule also includes new paperwork requirements for recordkeeping of malfunctions, as described in 40 CFR 63.454(g) (conducted in support of the affirmative defense provisions, as described in 40 CFR 63.456).

When a malfunction occurs, sources must report the event according to the applicable reporting requirements of 40 CFR part 63, subpart LLL. An affirmative defense to civil penalties for violations of emission limits that are caused by malfunctions is available to a source if it can demonstrate that certain criteria and requirements are satisfied. The criteria ensure that the affirmative defense is available only where the event that causes a violation of the emission limit meets the narrow definition of malfunction in 40 CFR 63.2 (sudden, infrequent, not reasonable preventable and not caused by poor maintenance and or careless operation) and where the source took necessary actions to minimize emissions. In addition, the source must meet certain notification and reporting requirements. For example, the source must prepare a written root cause analysis and submit a written report to the Administrator documenting that it has met the conditions and requirements for assertion of the affirmative defense.

The EPA is adding the paperwork and recordkeeping associated with the affirmative defense to civil penalties for malfunctions to the estimate of burden in the ICR. To provide the public with an estimate of the relative magnitude of the burden associated with an assertion of the affirmative defense position adopted by a source, the EPA has provided administrative adjustments to the ICR that show what the notification, recordkeeping and reporting requirements associated with the assertion of the affirmative defense might entail. The EPA's estimate for the required notification, reports and records for any individual incident, including the root cause analysis, totals $3,258, and is based on the time and effort required of a source to review relevant data, interview plant employees and document the events surrounding a malfunction that has caused a violation of an emissions limit. The estimate also includes time to produce and retain the record and reports for submission to the EPA. The EPA provides this illustrative estimate of this burden because these costs are only incurred if there has been a violation and a source chooses to take advantage of the affirmative defense.

Given the variety of circumstances under which malfunctions could occur, as well as differences among sources' operation and maintenance practices, we cannot reliably predict the severity and frequency of malfunction-related excess emissions events for a particular source. It is important to note that the EPA has no basis currently for estimating the number of malfunctions that would qualify for an affirmative defense. Current historical records would be an inappropriate basis, as source owners or operators previously operated their facilities in recognition that they were exempt from the requirement to comply with emissions standards during malfunctions. Of the number of excess emissions events reported by source operators, only a small number would be expected to result from a malfunction (based on the definition above), and only a subset of violations caused by malfunctions would result in the source choosing to assert the affirmative defense. Thus, we expect the number of instances in which source operators might be expected to avail themselves of the affirmative defense will be extremely small. For this reason, we estimate no more than two such occurrences per year for all sources subject to subpart LLL over the 3-year period covered by this ICR. We expect to gather information on such events in the future and will revise this estimate as better information becomes available.

We estimate 86 facilities will be subject to all final standards. The remaining 14 facilities will only be subject to the open clinker pile standards in this action. The annual monitoring, reporting and recordkeeping cost for this source (averaged over the first three years after the effective date of the standards) for these amendments to subpart LLL is estimated to be $352,814 per year for the industry. This includes 496 labor hours per year at a total labor cost of $47,806 per year, and total non-labor capital and operation and maintenance costs of $305,008 per year. This estimate includes reporting and recordkeeping associated with the requirements for open clinker storage piles. The total burden to the federal government (averaged over the first three years after the effective date of the standard) as a result of these amendments is estimated to be 263 hours per year at a total labor cost of $11,885 per year. Burden is defined at 5 CFR 1320.3(b).

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for the 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 will not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small organizations and small governmental jurisdictions.

For purposes of assessing the impact of this rule on small entities, small entity is defined as: (1) A small business whose parent company has no more than 750 employees based on the size definition for the affected NAICS code (327310), as defined by the 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.

We estimate that 3 of the 26 existing Portland cement entities are small entities and comprise 3 plants. After considering the economic impacts of this final rule on small entities, I certify that this action will not have a significant economic impact on a substantial number of small entities. Of the three affected small entities, all are expected to incur an annual compliance cost of less than 1.0 percent of sales to comply with these amendments to the 2010 final rule (reflecting potential controls on piles, which are likely to have lower cost when compared to the 2010 rule requirements because these plants already have requirements for

control of open clinker storage piles in their title V permits).

Although this final rule will not have a significant economic impact on a substantial number of small entities, the EPA nonetheless adopted amendments which should reduce the impact of this final rule on small entities. For example, we are expanding the provision that allows periodic HCl performance tests as an alternative to HCl CEMS for sources equipped with wet scrubbers to also apply to those sources that use dry scrubbers. This final rule also adds an option for sources using wet or dry scrubbers for HCl control to use SO_2 as a monitored parameter. If these sources already have a CEMS for SO_2, then this will provide operational flexibility.

D. Unfunded Mandates Reform Act

This rule 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 the private sector in any one year. As discussed earlier in this preamble, there is an actual savings to the industry of $52 million per year. Thus, this final rule is not subject to the requirements of section 202 and 205 of the UMRA. This final action is also not subject to the requirements of section 203 of the UMRA because it contains no regulatory requirements that might significantly or uniquely affect small governments. This final action contains no requirements that apply to such governments, imposes no obligations upon them, and will not result in expenditures by them of $100 million or more in any one year or any disproportionate impacts on them.

E. Executive Order 13132: Federalism

This final action 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. None of the affected facilities are owned or operated by State governments. Thus, Executive Order 13132 does not apply to this action.

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

This action may have tribal implications, as specified in Executive Order 13175 (65 FR 67249, November 9, 2000). The EPA is aware of one tribally owned Portland cement facility currently subject to subpart LLL and that will be subject to this final rule. The provisions of this final rule are not expected to impose new substantial direct compliance costs on Tribal governments since the same control technologies that are necessary under the current NESHAP will be needed to meet the final emissions limits. The EPA has tried to reduce the impact of this final rule on Tribal owned facilities. For example, we are expanding the provision that allows periodic HCl performance tests as an alternative to HCl CEMS for sources equipped with wet scrubbers to also apply to those sources that use dry sorbent injection (i.e., dry scrubbing systems). This final rule adds an option for sources using wet or dry scrubbers for HCl control to use SO_2 as a monitored parameter. If these sources already have a CEMS for SO_2, then this will provide operational flexibility.

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

The 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 final action 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 amendments do not require the use of additional controls as compared to the 2010 rule and may allow the industry to reduce its cost of compliance by increasing the industry's flexibility to institute different and less costly control strategies than under the 2010 rule.

I. National Technology Transfer and Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act of 1995 (''NTTAA''), Public Law No. 104–113 (15 U.S.C. 272 note), directs the 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 the EPA to provide Congress, through OMB, explanations when the agency decides not to use available and applicable VCS.

This final rulemaking does not involve technical standards. Therefore, the EPA is not considering the use of any voluntary consensus standards.

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.

An analysis of demographic data was prepared for the 2010 final rule and can be found in the docket for that rulemaking (See docket item EPA–HQ–OAR–2002–0051–3415). The impacts of the 2010 rule, which assumed full compliance, are expected to be unchanged as a result of this action. Therefore, beginning from the date of full compliance, the EPA has determined that this final rule will not have disproportionately high and adverse human health or environmental effects on minority or low-income populations because it increases the level of environmental protection for all affected populations without having any disproportionately high and adverse human health or environmental effects on any population, including any minority or low-income populations. In addition, the full benefits of this final rule will not result until 2015 due to the final amended compliance date but the demographic analysis showed that the average of populations in close proximity to the sources, and thus most likely to be affected by the sources, were similar in demographic composition to national averages.

K. Congressional Review Act

The Congressional Review Act, 5 U.S.C. 801, *et seq.*, as added by the Small Business Regulatory Enforcement Fairness Act of 1996, generally provides that, before a rule may take effect, the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of the

Congress and to the Comptroller General of the United States. The EPA will submit a report containing this final rule and other required information to the U.S. Senate, the U.S. House of Representatives and the Comptroller General of the United States prior to publication of the rule in the **Federal Register**. A major rule cannot take effect until 60 days after it is published in the **Federal Register**. This action is not a ''major rule'' as defined by 5 U.S.C. 804(2). This final rule will be effective on February 12, 2013.

List of Subjects in 40 CFR Part 63

Environmental protection, Air pollution control, Hazardous substances, Reporting and recordkeeping requirements.

Dated: December 20, 2012.

Lisa P. Jackson,

Administrator.

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

PART 60—[AMENDED]

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

Authority: 23 U.S.C. 101; 42 U.S.C. 7401–7671q.

Subpart F—[AMENDED]

■ 2. Section 60.61 is amended by adding paragraphs (e) and (f) to read as follows:

§ 60.61 Definitions.

* * * * *

(e) *Excess emissions* means, with respect to this subpart, results of any required measurements outside the applicable range (e.g., emissions limitations, parametric operating limits) that is permitted by this subpart. The values of measurements will be in the same units and averaging time as the values specified in this subpart for the limitations.

(f) *Operating day* means a 24-hour period beginning at 12:00 midnight during which the kiln operates at any time. For calculating rolling 30-day average emissions, an *operating day* does not include the hours of operation during startup or shutdown.

* * * * *

■ 3. Section 60.62 is amended by:

■ a. Removing and reserving paragraph (a)(1)(i), revising paragraph (a)(1)(ii) and adding paragraph (a)(1)(iii);

■ b. Removing and reserving paragraph (a)(2);

■ c. Revising paragraphs (b)(1)(i) and (ii);

■ d. Removing paragraph (b)(2);

■ e. Redesignating paragraphs (b)(3) and (4) as (b)(2) and (3);

■ f. Revising newly designated paragraph (b)(3); and

■ g. Revising paragraph (d).

The revisions read as follows:

§ 60.62 Standards.

(a) * * *

(1) * * *

(ii) 0.02 pound per ton of clinker if construction or reconstruction of the kiln commenced after June 16, 2008.

(iii) Kilns that have undergone a modification may not discharge into the atmosphere any gases which contain PM in excess of 0.07 pound per ton of clinker.

* * * * *

(b) * * *

(1) * * *

(i) 0.02 pound per ton of clinker if construction or reconstruction of the clinker cooler commences after June 16, 2008.

(ii) 0.07 pound per ton of clinker if the clinker cooler has undergone a modification.

* * * * *

(3) If the kiln has a separated alkali bypass stack and/or an inline coal mill with a separate stack, you must combine the PM emissions from the bypass stack and/or the inline coal mill stack with the PM emissions from the main kiln exhaust to determine total PM emissions.

* * * * *

(d) If you have an affected source subject to this subpart with a different emissions limit or requirement for the same pollutant under another regulation in title 40 of this chapter, you must comply with the most stringent emissions limit or requirement and are not subject to the less stringent requirement.

■ 4. Section 60.63 is amended by:

■ a. Revising paragraphs (b)(1)(i) and (ii);

■ b. Adding paragraph (b)(1)(iii);

■ c. Revising paragraphs (b)(2) and (3);

■ d. Removing paragraph (b)(4);

■ e. Revising paragraphs (c) through (f);

■ f. Revising paragraph (g) introductory text;

■ g. Revising paragraph (g)(2);

■ h. Revising paragraph (h) introductory text;

■ i. Revising paragraphs (h)(1) and (6);

■ j. Revising paragraph (h)(7) introductory text;

■ k. Revising paragraph (h)(8) introductory text;

■ l. Revising paragraph (h)(9);

■ m. Revising paragraph (i) introductory text; and

■ n. Revising paragraph (i)(1) introductory text and (i)(1)(i).

The revisions and addition read as follows:

§ 60.63 Monitoring of operations.

* * * * *

(b) * * *

(1) * * *

(i) Install, calibrate, maintain, and operate a permanent weigh scale system to measure and record weight rates of the amount of clinker produced in tons of mass per hour. The system of measuring hourly clinker production must be maintained within ±5 percent accuracy or

(ii) Install, calibrate, maintain, and operate a permanent weigh scale system to measure and record weight rates of the amount of feed to the kiln in tons of mass per hour. The system of measuring feed must be maintained within ±5 percent accuracy. Calculate your hourly clinker production rate using a kiln specific feed-to-clinker ratio based on reconciled clinker production rates determined for accounting purposes and recorded feed rates. This ratio should be updated monthly. Note that if this ratio changes at clinker reconciliation, you must use the new ratio going forward, but you do not have to retroactively change clinker production rates previously estimated.

(iii) For each kiln operating hour for which you do not have data on clinker production or the amount of feed to the kiln, use the value from the most recent previous hour for which valid data are available.

(2) Determine, record, and maintain a record of the accuracy of the system of measuring hourly clinker production rates or feed rates before initial use (for new sources) or by the effective compliance date of this rule (for existing sources). During each quarter of source operation, you must determine, record, and maintain a record of the ongoing accuracy of the system of measuring hourly clinker production rates or feed rates.

(3) If you measure clinker production directly, record the daily clinker production rates; if you measure the kiln feed rates and calculate clinker production, record the daily kiln feed and clinker production rates.

(c) *PM Emissions Monitoring Requirements.* (1) For each kiln or clinker cooler subject to a PM emissions limit in § 60.62, you must demonstrate compliance through an initial performance test. You will conduct your performance test using Method 5 or Method 5I at appendix A–3 to part 60 of this chapter. You must also monitor continuous performance through use of

a PM continuous parametric monitoring system (PM CPMS).

(2) For your PM CPMS, you will establish a site-specific operating limit. If your PM performance test demonstrates your PM emission levels to be below 75 percent of your emission limit you will use the average PM CPMS value recorded during the PM compliance test, the milliamp equivalent of zero output from your PM CPMS, and the average PM result of your compliance test to establish your operating limit equivalent to 75 percent of the standard. If your PM compliance test demonstrates your PM emission levels to be at or above 75 percent of your emission limit you will use the average PM CPMS value recorded during the PM compliance test demonstrating compliance with the PM limit to establish your operating limit. You will use the PM CPMS to demonstrate continuous compliance with your operating limit. You must repeat the performance test annually and reassess and adjust the site-specific operating limit in accordance with the results of the performance test.

(i) Your PM CPMS must provide a 4–20 milliamp output and the establishment of its relationship to manual reference method measurements must be determined in units of milliamps.

(ii) Your PM CPMS operating range must be capable of reading PM concentrations from zero to a level equivalent to two times your allowable emission limit. If your PM CPMS is an auto-ranging instrument capable of multiple scales, the primary range of the instrument must be capable of reading PM concentration from zero to a level equivalent to two times your allowable emission limit.

(iii) During the initial performance test or any such subsequent performance test that demonstrates compliance with the PM limit, record and average all milliamp output values from the PM CPMS for the periods corresponding to the compliance test runs (e.g., average all your PM CPMS output values for three corresponding 2-hour Method 5I test runs).

(3) Determine your operating limit as specified in paragraphs (c)(4)(i) through (c)(5) of this section. If your PM performance test demonstrates your PM emission levels to be below 75 percent of your emission limit you will use the average PM CPMS value recorded during the PM compliance test, the milliamp equivalent of zero output from your PM CPMS, and the average PM result of your compliance test to establish your operating limit. If your PM compliance test demonstrates your PM emission levels to be at or above 75 percent of your emission limit you will use the average PM CPMS value recorded during the PM compliance test to establish your operating limit. You must verify an existing or establish a new operating limit after each repeated performance test. You must repeat the performance test at least annually and reassess and adjust the site-specific operating limit in accordance with the results of the performance test.

(4) If the average of your three Method 5 or 5I compliance test runs are below 75 percent of your PM emission limit, you must calculate an operating limit by establishing a relationship of PM CPMS signal to PM concentration using the PM CPMS instrument zero, the average PM CPMS values corresponding to the three compliance test runs, and the average PM concentration from the Method 5 or 5I compliance test with the procedures in (c)(4)(i)(A) through (D) of this section.

(i) Determine your PM CPMS instrument zero output with one of the following procedures.

(A) Zero point data for in-situ instruments should be obtained by removing the instrument from the stack and monitoring ambient air on a test bench.

(B) Zero point data for extractive instruments should be obtained by removing the extractive probe from the stack and drawing in clean ambient air.

(C) The zero point can also can be obtained by performing manual reference method measurements when the flue gas is free of PM emissions or contains very low PM concentrations (e.g., when your process is not operating, but the fans are operating or your source is combusting only natural gas) and plotting these with the compliance data to find the zero intercept.

(D) If none of the steps in paragraphs (c)(4)(i)(A) through (C) of this section are possible, you must use a zero output value provided by the manufacturer.

(ii) Determine your PM CPMS instrument average in milliamps, and the average of your corresponding three PM compliance test runs, using equation 1.

$$\bar{x} = \frac{1}{n}\sum_{i=1}^{n} X_1 \,, \bar{y} = \frac{1}{n}\sum_{i=1}^{n} Y_1 \qquad \text{(Eq. 1)}$$

Where:

X1 = The PM CPMS data points for the three runs constituting the performance test,

Y1 = The PM concentration value for the three runs constituting the performance test, and

n = The number of data points.

(iii) With your PM CPMS instrument zero expressed in milliamps, your three run average PM CPMS milliamp value, and your three run average PM concentration from your three PM performance test runs, determine a relationship of lb/ton-clinker per milliamp with equation 2.

$$R = \frac{Y_1}{(X_1 - z)} \qquad \text{(Eq. 2)}$$

Where:

R = The relative lb/ton clinker per milliamp for your PM CPMS.

Y1 = The three run average PM lb/ton clinker.

X1 = The three run average milliamp output from you PM CPMS.

z = the milliamp equivalent of your instrument zero determined from (c)(4)(i) of this section.

(iv) Determine your source specific 30-day rolling average operating limit using the lb/ton-clinker per milliamp value from Equation 2 above in Equation 3, below. This sets your operating limit at the PM CPMS output value corresponding to 75 percent of your emission limit.

$$O_l = z + (0.75(L)) / R \qquad \text{(Eq. 3)}$$

Where:

O_l = The operating limit for your PM CPMS on a 30-day rolling average, in milliamps.

L = Your source emission limit expressed in lb/ton clinker.

z = Your instrument zero in milliamps, determined from (1)(i).

R = The relative lb/ton-clinker per milliamp for your PM CPMS, from Equation 2.

(5) If the average of your three PM compliance test runs is at or above 75 percent of your PM emission limit you must determine your operating limit by averaging the PM CPMS milliamp output corresponding to your three PM performance test runs that demonstrate compliance with the emission limit using Equation 4.

$$O_h = \frac{1}{n}\sum_{i=1}^{n} X_1 \qquad \text{(Eq. 4)}$$

Where:

X1 = The PM CPMS data points for all runs i.

n = The number of data points.

O_h = Your site specific operating limit, in milliamps.

(6) To determine continuous compliance, you must record the PM CPMS output data for all periods when the process is operating, and use all the PM CPMS data for calculations when the source is not out-of-control. You must demonstrate continuous compliance by using all quality-assured hourly average data collected by the PM CPMS for all operating hours to calculate the arithmetic average operating parameter in units of the operating limit (milliamps) on a 30 operating day rolling average basis, updated at the end of each new kiln operating day. Use Equation 5 to determine the 30 kiln operating day average.

$$\text{30kiln operating day average} = \frac{\sum_{i=1}^{n} Hpv_i}{n} \qquad \text{(Eq. 5)}$$

Where:

Hpvi = The hourly parameter value for hour i.

n = The number of valid hourly parameter values collected over 30 kiln operating days.

(7) Use EPA Method 5 or Method 5I of appendix A to part 60 of this chapter to determine PM emissions. For each performance test, conduct at least three separate runs under the conditions that exist when the affected source is operating at the highest load or capacity level reasonably expected to occur. Conduct each test run to collect a minimum sample volume of 2 dscm for determining compliance with a new source limit and 1 dscm for determining compliance with an existing source limit. Calculate the average of the results from three consecutive runs to determine compliance. You need not determine the particulate matter collected in the impingers (''back half'') of the Method 5 or Method 5I particulate sampling train to demonstrate compliance with the PM standards of this subpart. This shall not preclude the permitting authority from requiring a determination of the ''back half'' for other purposes.

(8) For PM performance test reports used to set a PM CPMS operating limit, the electronic submission of the test report must also include the make and model of the PM CPMS instrument, serial number of the instrument, analytical principle of the instrument (e.g. beta attenuation), span of the instruments primary analytical range, milliamp value equivalent to the instrument zero output, technique by which this zero value was determined, and the average milliamp signals corresponding to each PM compliance test run.

(d) You must install, operate, calibrate, and maintain a CEMS continuously monitoring and recording the concentration by volume of NO_X emissions into the atmosphere for any kiln subject to the NO_X emissions limit in § 60.62(a)(3). If the kiln has an alkali bypass, NO_X emissions from the alkali bypass do not need to be monitored, and NO_X emission monitoring of the kiln exhaust may be done upstream of any commingled alkali bypass gases.

(e) You must install, operate, calibrate, and maintain a CEMS for continuously monitoring and recording the concentration by volume of SO_2 emissions into the atmosphere for any kiln subject to the SO_2 emissions limit in § 60.62(a)(4). If you are complying with the alternative 90 percent SO_2 emissions reduction emissions limit, you must also continuously monitor and record the concentration by volume of SO_2 present at the wet scrubber inlet.

(f) The NO_X and SO_2 CEMS required under paragraphs (d) and (e) of this section must be installed, operated and maintained according to Performance Specification 2 of appendix B of this part and the requirements in paragraphs (f)(1) through (5) of this section.

(1) The span value of each NO_X CEMS monitor must be set at 125 percent of the maximum estimated hourly potential NO_X emission concentration that translates to the applicable emissions limit at full clinker production capacity.

(2) You must conduct performance evaluations of each NO_X CEMS monitor according to the requirements in § 60.13(c) and Performance Specification 2 of appendix B to this part. You must use Methods 7, 7A, 7C, 7D, or 7E of appendix A–4 to this part for conducting the relative accuracy evaluations. The method ASME PTC 19.10–1981, ''Flue and Exhaust Gas Analyses,'' (incorporated by reference—see § 60.17) is an acceptable alternative to Method 7 or 7C of appendix A–4 to this part.

(3) The span value for the SO_2 CEMS monitor is the SO_2 emission concentration that corresponds to 125 percent of the applicable emissions limit at full clinker production capacity

and the expected maximum fuel sulfur content.

(4) You must conduct performance evaluations of each SO_2 CEMS monitor according to the requirements in § 60.13(c) and Performance Specification 2 of appendix B to this part. You must use Methods 6, 6A, or 6C of appendix A–4 to this part for conducting the relative accuracy evaluations. The method ASME PTC 19.10–1981, ''Flue and Exhaust Gas Analyses,'' (incorporated by reference—see § 60.17) is an acceptable alternative to Method 6 or 6A of appendix A–4 to this part.

(5) You must comply with the quality assurance requirements in Procedure 1 of appendix F to this part for each NO_X and SO_2 CEMS, including quarterly accuracy determinations for monitors, and daily calibration drift tests.

(g) For each CPMS or CEMS required under paragraphs (c) through (e) of this section:

* * * * *

(2) You may not use data recorded during the monitoring system malfunctions, repairs associated with monitoring system malfunctions, or required monitoring system quality assurance or control activities in calculations used to report emissions or operating levels. A monitoring system malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring system to provide valid data. Monitoring system failures that are caused in part by poor maintenance or careless operation are not malfunctions. An owner or operator must use all the data collected during all other periods in reporting emissions or operating levels.

* * * * *

(h) You must install, operate, calibrate, and maintain instruments for continuously measuring and recording the stack gas flow rate to allow determination of the pollutant mass emissions rate to the atmosphere for each kiln subject to the PM emissions limits in § 60.62(a)(1)(ii) and (iii) and (b)(1)(i) and (ii), the NO_X emissions limit in § 60.62(a)(3), or the SO_2 emissions limit in § 60.62(a)(4) according to the requirements in paragraphs (h)(1) through (10), where appropriate, of this section.

(1) The owner or operator must install each sensor of the flow rate monitoring system in a location that provides representative measurement of the exhaust gas flow rate at the sampling location of the NO_X and/or SO_2 CEMS, taking into account the manufacturer's recommendations. The flow rate sensor is that portion of the system that senses the volumetric flow rate and generates an output proportional to that flow rate.

* * * * *

(6) The flow rate monitoring system must be designed to measure a minimum of one cycle of operational flow for each successive 15-minute period.

(7) The flow rate sensor must be able to determine the daily zero and upscale calibration drift (CD) (see sections 3.1 and 8.3 of Performance Specification 2 in appendix B to this part for a discussion of CD).

* * * * *

(8) You must perform an initial relative accuracy test of the flow rate monitoring system according to section 8.2 of Performance Specification 6 of appendix B to this part, with the exceptions noted in paragraphs (h)(8)(i) and (ii) of this section.

* * * * *

(9) You must verify the accuracy of the flow rate monitoring system at least once per year by repeating the relative accuracy test specified in paragraph (h)(8) of this section.

* * * * *

(i) *Development and Submittal (Upon Request) of Monitoring Plans.* To demonstrate compliance with any applicable emissions limit through performance stack testing or other emissions monitoring (including PM CPMS), you must develop a site-specific monitoring plan according to the requirements in paragraphs (i)(1) through (4) of this section. This requirement also applies to you if you petition the EPA Administrator for alternative monitoring parameters under § 60.13(3)(i). If you use a bag leak detector system (BLDS), you must also meet the requirements specified in paragraph § 63.1350(m)(10) of this chapter.

(1) For each continuous monitoring system (CMS) required in this section, you must develop, and submit to the permitting authority for approval upon request, a site-specific monitoring plan that addresses paragraphs (i)(1)(i) through (iii) of this section. You must submit this site-specific monitoring plan, if requested, at least 30 days before the initial performance evaluation of your CMS.

(i) Installation of the CMS sampling probe or other interface at a measurement location relative to each affected process unit such that the measurement is representative of control of the exhaust emissions (e.g., on or downstream of the last control device);

* * * * *

■ 5. Section 60.64 is revised to read as follows:

§ 60.64 Test methods and procedures.

(a) In conducting the performance tests and relative accuracy tests required in § 60.8, you must use reference methods and procedures and the test methods in appendix A of this part or other methods and procedures as specified in this section, except as provided in § 60.8(b).

(b)(1)You must demonstrate compliance with the PM standards in § 60.62 using EPA method 5 or method 5I.

(2) Use Method 9 and the procedures in § 60.11 to determine opacity.

(3) Any sources other than kilns (including associated alkali bypass and clinker cooler) that are subject to the 10 percent opacity limit must follow the appropriate monitoring procedures in § 63.1350(f), (m)(1)through (4), (10) and (11), (o), and (p) of this chapter.

(c) Calculate and record the rolling 30 kiln operating day average emission rate daily of NO_X and SO_2 according to the procedures in paragraphs (c)(1) and (2) of this section.

(1) Calculate the rolling 30 kiln operating day average emissions according to equation 6:

$$E_{30D} = k \frac{\sum_{i=1}^{n} C_i Q_i}{P} \qquad \text{(Eq. 6)}$$

Where:

E_{30D} = 30 kiln operating day average emission rate of NO_X or SO_2, lb/ton of clinker.

C_i = Concentration of NO_X or SO_2 for hour i, ppm.

Q_i = Volumetric flow rate of effluent gas for hour i, where

C_i and Q_i are on the same basis (either wet or dry), scf/hr.

P = 30 days of clinker production during the same time period as the NO_X or SO_2 emissions measured, tons.

k = Conversion factor, 1.194×10^{7} for NO_X and 1.660×10^{7} for SO_2, lb/scf/ppm.

n = Number of kiln operating hours over 30 kiln operating days.

(2) For each kiln operating hour for which you do not have at least one valid 15-minute CEMS data value, use the average emissions rate (lb/hr) from the most recent previous hour for which valid data are available.

(d)(1) Within 60 days after the date of completing each performance test (see § 60.8) as required by this subpart you must submit the results of the performance tests conducted to demonstrate compliance under this subpart to the EPA's WebFIRE database by using the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through the EPA's Central Data Exchange (CDX) (*http://www.epa.gov/cdx*). Performance test data must be submitted in the file format generated through use of the EPA's Electronic Reporting Tool (ERT) (see *http://www.epa.gov/ttn/chief/ert/index.html*). Only data collected using test methods on the ERT Web site are subject to this requirement for submitting reports electronically to WebFIRE. Owners or operators who claim that some of the information being submitted for performance tests is confidential business information (CBI) must submit a complete ERT file including information claimed to be CBI on a compact disk, flash drive or other commonly used electronic storage media to the EPA. The electronic media must be clearly marked as CBI and mailed to U.S. EPA/OAPQS/CORE CBI Office, Attention: WebFIRE Administrator, MD C404–02, 4930 Old Page Rd., Durham, NC 27703. The same ERT file with the CBI omitted must be submitted to the EPA via CDX as described earlier in this paragraph. At the discretion of the delegated authority, you must also submit these reports, including the CBI, to the delegated authority in the format specified by the delegated authority. For any performance test conducted using test methods that are not listed on the ERT Web site, you must submit the results of the performance test to the Administrator at the appropriate address listed in § 63.13.

(2) Within 60 days after the date of completing each CEMS performance evaluation test as defined in § 63.2, you must submit relative accuracy test audit (RATA) data to the EPA's CDX by using CEDRI in accordance with paragraph (d)(1) of this section. Only RATA pollutants that can be documented with the ERT (as listed on the ERT Web site) are subject to this requirement. For any performance evaluations with no corresponding RATA pollutants listed on the ERT Web site, you must submit the results of the performance evaluation to the Administrator at the appropriate address listed in § 63.13.

(3) For PM performance test reports used to set a PM CPMS operating limit, the electronic submission of the test report must also include the make and model of the PM CPMS instrument, serial number of the instrument, analytical principle of the instrument (e.g. beta attenuation), span of the instruments primary analytical range, milliamp value equivalent to the instrument zero output, technique by which this zero value was determined, and the average milliamp signals corresponding to each PM compliance test run.

(4) All reports required by this subpart not subject to the requirements in paragraphs (d)(1) and (2) of this section must be sent to the Administrator at the appropriate address listed in § 63.13. The Administrator or the delegated authority may request a report in any form suitable for the specific case (e.g., by commonly used electronic media such as Excel spreadsheet, on CD or hard copy). The Administrator retains the right to require submittal of reports subject to paragraph (d)(1) and (2) of this section in paper format.

■ 6. Section 60.65 is revised to read as follows:

§ 60.65 Recordkeeping and reporting requirements.

(a) Each owner or operator required to install a CPMS or CEMS under sections § 60.63(c) through (e) shall submit reports of excess emissions. The content of these reports must comply with the requirements in § 60.7(c). Notwithstanding the provisions of § 60.7(c), such reports shall be submitted semiannually.

(b) Each owner or operator of facilities subject to the provisions of § 60.63(c) through (e) shall submit semiannual reports of the malfunction information required to be recorded by § 60.7(b). These reports shall include the frequency, duration, and cause of any incident resulting in deenergization of any device controlling kiln emissions or in the venting of emissions directly to the atmosphere.

(c) The requirements of this section remain in force until and unless the Agency, in delegating enforcement authority to a State under section 111(c) of the Clean Air Act, 42 U.S.C. 7411, approves reporting requirements or an alternative means of compliance surveillance adopted by such States. In that event, affected sources within the State will be relieved of the obligation to comply with this section, provided that they comply with the requirements established by the State.

■ 7. Section 60.66 is amended by revising paragraph (b) introductory text to read as follows:

§ 60.66 Delegation of authority.

* * * * *

(b) In delegating implementation and enforcement authority 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.

* * * * *

PART 63—NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS FOR SOURCE CATEGORIES

■ 8. The authority citation for part 63 continues to read as follows:

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

Subpart LLL—[Amended]

■ 9. Section 63.1340 is amended by revising paragraphs (b)(1), (b)(6) through (9), and (c) to read as follows:

§ 63.1340 What parts of my plant does this subpart cover?

* * * * *

(b) * * *:

(1) Each kiln including alkali bypasses and inline coal mills, except for kilns that burn hazardous waste and are subject to and regulated under subpart EEE of this part;

* * * * *

(6) Each raw material, clinker, or finished product storage bin at any portland cement plant that is a major source;

(7) Each conveying system transfer point including those associated with coal preparation used to convey coal from the mill to the kiln at any portland cement plant that is a major source;

(8) Each bagging and bulk loading and unloading system at any portland cement plant that is a major source; and

(9) Each open clinker storage pile at any portland cement plant.

(c) Onsite sources that are subject to standards for nonmetallic mineral processing plants in subpart OOO, part 60 of this chapter are not subject to this subpart. Crushers are not covered by this subpart regardless of their location.

* * * * *

■ 10. Section 63.1341 is amended by:

■ a. Removing definitions of ''Enclosed storage pile,'' and ''Inactive clinker pile'';

■ b. Adding a definition for ''In-line coal mill,'' ''Open clinker storage pile,'' ''Startup,'' and ''Shutdown'' in alphabetical order; and

■ c. Revising definitions for ''Kiln,'' ''New source,'' ''Operating day,'' ''Raw material dryer,'' and ''Total organic HAP,''.

The additions and revisions read as follows:

§ 63.1341 Definitions.

* * * * *

In-line coal mill means those coal mills using kiln exhaust gases in their process. Coal mills with a heat source other than the kiln or coal mills using exhaust gases from the clinker cooler are not an in-line coal mill.

* * * * *

Kiln means a device, including any associated preheater or precalciner devices, inline raw mills, inline coal mills or alkali bypasses that produces clinker by heating limestone and other materials for subsequent production of portland cement. Because the inline raw mill and inline coal mill are considered an integral part of the kiln, for purposes of determining the appropriate emissions limit, the term kiln also applies to the exhaust of the inline raw mill and the inline coal mill.

* * * * *

New source means any source that commenced construction or reconstruction after May 6, 2009, for purposes of determining the applicability of the kiln, clinker cooler and raw material dryer emissions limits for mercury, PM, THC, and HCl.

* * * * *

Open clinker storage pile means a clinker storage pile on the ground for more than three days that is not completely enclosed in a building or structure.

Operating day means any 24-hour period beginning at 12:00 midnight during which the kiln operates for any time. For calculating the rolling 30-day average emissions, kiln operating days do not include the hours of operation during startup or shutdown.

* * * * *

Raw material dryer means an impact dryer, drum dryer, paddle-equipped rapid dryer, air separator, or other equipment used to reduce the moisture content of feed or other materials.

* * * * *

Shutdown means the cessation of kiln operation. Shutdown begins when feed to the kiln is halted and ends when continuous kiln rotation ceases.

* * * * *

Startup means the time from when a shutdown kiln first begins firing fuel until it begins producing clinker. Startup begins when a shutdown kiln turns on the induced draft fan and begins firing fuel in the main burner. Startup ends when feed is being continuously introduced into the kiln for at least 120 minutes or when the feed rate exceeds 60 percent of the kiln design limitation rate, whichever occurs first.

* * * * *

Total organic HAP means, for the purposes of this subpart, the sum of the concentrations of compounds of formaldehyde, benzene, toluene, styrene, m-xylene, p-xylene, o-xylene, acetaldehyde, and naphthalene as measured by EPA Test Method 320 or Method 18 of appendix A to this part or ASTM D6348–03 [1] or a combination of these methods, as appropriate. If measurement results for any pollutant are reported as below the method detection level (e.g., laboratory analytical results for one or more sample components are below the method defined analytical detection level), you must use the method detection level as the measured emissions level for that pollutant in calculating the total organic HAP value. The measured result for a multiple component analysis (e.g., analytical values for multiple Method 18 fractions) may include a combination of method detection level data and analytical data reported above the method detection level. The owner or operator of an affected source may request the use of other test methods to make this determination under paragraphs 63.7(e)(2)(ii) and (f) of this part.

* * * * *

■ 11. Section 63.1343 is revised to read as follows:

§ 63.1343 What standards apply to my kilns, clinker coolers, raw material dryers, and open clinker storage piles?

(a) *General.* The provisions in this section apply to each kiln and any alkali bypass associated with that kiln, clinker cooler, raw material dryer, and open clinker storage pile. All D/F, HCl, and total hydrocarbon (THC) emissions limit are on a dry basis. The D/F, HCl, and THC limits for kilns are corrected to 7 percent oxygen. All THC emissions limits are measured as propane. Standards for mercury and THC are based on a rolling 30-day average. If using a CEMS to determine compliance with the HCl standard, this standard is based on a rolling 30-day average. You must ensure appropriate corrections for moisture are made when measuring flow rates used to calculate mercury emissions. The 30-day period means 30 consecutive kiln operating days excluding periods of startup and shutdown. All emissions limits for kilns, clinker coolers, and raw material dryers currently in effect that are superseded by the limits below continue to apply until the compliance date of the limits below, or until the source certifies compliance with the limits below, whichever is earlier.

(b) *Kilns, clinker coolers, raw material dryers, raw mills, and finish mills.* (1) The emissions limits for these sources are shown in Table 1 below. PM limits for existing kilns also apply to kilns that have undergone a modification as defined in subpart A of part 60 of title 40.

[1] When using ASTM D6348–03, the following conditions must be met:

(1) The test plan preparation and implementation in the Annexes to ASTM D6348–03, Sections A1 through A8 are mandatory; (2) For ASTM D6348–03 Annex A5 (Analyte Spiking Technique), the percent R must be determined for each target analyte (see Equation A5.5); (3) For the ASTM D6348–03 test data to be acceptable for a target analyte percent R must be 70 percent ≥ R ≤ 130 percent; and (4) The percent R value for each compound must be reported in the test report and all field measurements corrected with the calculated percent R value for that compound using the following equation: Reported Result = The measured concentration in the stack divided by the calculated percent R value and then the whole term multiplied by 100.

TABLE 1—EMISSIONS LIMITS FOR KILNS, CLINKER COOLERS, RAW MATERIAL DRYERS, RAW AND FINISH MILLS

	If your source is a (an):	And the operating mode is:	And if is located at a:	Your emissions limits are:	And the units of the emissions limit are:	The oxygen correction factor is:
1.	Existing kiln	Normal operation	Major or area source	PM [1] 0.07	lb/ton clinker	NA.
				D/F [2] 0.2	ng/dscm (TEQ)	7 percent.
				Mercury 55	lb/MM tons clinker	NA.
				THC [3 4] 24	ppmvd	7 percent.
2.	Existing kiln	Normal operation	Major source	HCl 3	ppmvd	7 percent.
3.	Existing kiln	Startup and shutdown.	Major or area source	Work practices (63.1346(f))	NA	NA.
4.	New kiln	Normal operation	Major or area source	PM 0.02	lb/ton clinker	NA.
				D/F [2] 0.2	ng/dscm (TEQ)	7 percent.
				Mercury 21	lb/MM tons clinker	NA
				THC [3 4] 24	ppmvd	7 percent.
5.	New kiln	Normal operation	Major source	HCl 3	ppmvd	7 percent.
6.	New kiln	Startup and shutdown.	Major or area source	Work practices (63.1346(f))	NA	NA.
7.	Existing clinker cooler.	Normal operation	Major or area source	PM 0.07	lb/ton clinker	NA.
8.	Existing clinker cooler.	Startup and shutdown.	Major or area source	Work practices (63.1348(b)(9))	NA	NA.
9.	New clinker cooler	Normal operation	Major or area source	PM 0.02	lb/ton clinker	NA.
10.	New clinker cooler	Startup and shutdown.	Major or area source	Work practices (63.1348(b)(9))	NA	NA.
11.	Existing or new raw material dryer.	Normal operation	Major or area source	THC [3 4] 24	ppmvd	NA.
12.	Existing or new raw material dryer.	Startup and shutdown.	Major or area source	Work practices (63.1348(b)(9))	NA	NA.
13.	Existing or new raw or finish mill.	All operating modes	Major source	Opacity 10	percent	NA.

[1] The initial and subsequent PM performance tests are performed using Method 5 or 5I and consist of three 1-hr tests.
[2] If the average temperature at the inlet to the first PM control device (fabric filter or electrostatic precipitator) during the D/F performance test is 400 °F or less this limit is changed to 0.40 ng/dscm (TEQ).
[3] Measured as propane.
[4] Any source subject to the 24 ppmvd THC limit may elect to meet an alternative limit of 12 ppmvd for total organic HAP.

(2) When there is an alkali bypass and/or an inline coal mill with a separate stack associated with a kiln, the combined PM emissions from the kiln and the alkali bypass stack and/or the inline coal mill stack are subject to the PM emissions limit. Existing kilns that combine the clinker cooler exhaust and/or coal mill exhaust with the kiln exhaust and send the combined exhaust to the PM control device as a single stream may meet an alternative PM emissions limit. This limit is calculated using Equation 1 of this section:

$$PM_{alt} = (0.0060 \times 1.65)(Q_k + Q_c + Q_{ab} + Q_{cm})/(7000) \quad \text{(Eq. 1)}$$

Where:

PM_{alt} = Alternative PM emission limit for commingled sources.

0.006 = The PM exhaust concentration (gr/dscf) equivalent to 0.070 lb per ton clinker where clinker cooler and kiln exhaust gas are not combined.

1.65 = The conversion factor of ton feed per ton clinker.

Q_k = The exhaust flow of the kiln (dscf/ton feed).

Q_c = The exhaust flow of the clinker cooler (dscf/ton feed).

Q_{ab} = The exhaust flow of the alkali bypass (dscf/ton feed).

Q_{cm} = The exhaust flow of the coal mill (dscf/ton feed).

7000 = The conversion factor for grains (gr) per lb.

For new kilns that combine kiln exhaust and clinker cooler gas the limit is calculated using the Equation 2 of this section:

$$PM_{alt} = (0.0020 \times 1.65)(Q_k + Q_c + Q_{ab} + Q_{cm})/(7000) \quad \text{(Eq. 2)}$$

Where:

PM_{alt} = Alternative PM emission limit for commingled sources.

0.002 = The PM exhaust concentration (gr/dscf) equivalent to 0.020 lb per ton clinker where clinker cooler and kiln exhaust gas are not combined.

1.65 = The conversion factor of ton feed per ton clinker.

Q_k = The exhaust flow of the kiln (dscf/ton feed).

Q_c = The exhaust flow of the clinker cooler (dscf/ton feed).

Q_{ab} = The exhaust flow of the alkali bypass (dscf/ton feed).

Q_{cm} = The exhaust flow of the coal mill (dscf/ton feed).

7000 = The conversion factor for gr per lb.

(c) *Open clinker storage pile.* The owner or operator of an open clinker storage pile must prepare, and operate in accordance with, the fugitive dust emissions control measures, described in their operation and maintenance plan (see § 63.1347 of this subpart), that is appropriate for the site conditions as specified in paragraphs (c)(1) through

(3) of this section. The operation and maintenance plan must also describe the measures that will be used to minimize fugitive dust emissions from piles of clinker, such as accidental spillage, that are not part of open clinker storage piles.

(1) The operation and maintenance plan must identify and describe the location of each current or future open clinker storage pile and the fugitive dust emissions control measures the owner or operator will use to minimize fugitive dust emissions from each open clinker storage pile.

(2) For open clinker storage piles, the operations and maintenance plan must specify that one or more of the following control measures will be used to minimize to the greatest extent practicable fugitive dust from open clinker storage piles: Locating the source inside a partial enclosure, installing and operating a water spray or fogging system, applying appropriate chemical dust suppression agents, use of a wind barrier, compaction, use of tarpaulin or other equally effective cover or use of a vegetative cover. You must select, for inclusion in the operations and maintenance plan, the fugitive dust control measure or measures listed in this paragraph that are most appropriate for site conditions. The plan must also explain how the measure or measures selected are applicable and appropriate for site conditions. In addition, the plan must be revised as needed to reflect any changing conditions at the source.

(3) Temporary piles of clinker that result from accidental spillage or clinker storage cleaning operations must be cleaned up within 3 days.

(d) Emission limits in effect prior to September 9, 2010. Any source defined as an existing source in § 63.1351, and that was subject to a PM, mercury, THC, D/F, or opacity emissions limit prior to September 9, 2010, must continue to meet the limits shown in Table 2 to this section until September 9, 2015.

■ 12. Section 63.1344 is revised to read as follows:

§ 63.1344 Affirmative Defense for Violation of Emission Standards During Malfunction.

In response to an action to enforce the standards set forth in § 63.1343(b) and (c) and § 63.1345 and you may assert an affirmative defense to a claim for civil penalties for violations of such standards that are caused by malfunction, as defined at 40 CFR 63.2. Appropriate penalties may be assessed if you fail to meet your burden of proving all of the requirements in the affirmative defense. The affirmative defense shall not be available for claims for injunctive relief.

(a) *Assertion of affirmative defense.* To establish the affirmative defense in any action to enforce such a standard, you must timely meet the reporting requirements in paragraph (b) of this section, and must prove by a preponderance of evidence that:

(1) The violation:

(i) Was caused by a sudden, infrequent, and unavoidable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner; and

(ii) Could not have been prevented through careful planning, proper design or better operation and maintenance practices; and

(iii) Did not stem from any activity or event that could have been foreseen and avoided, or planned for; and

(iv) Was not part of a recurring pattern indicative of inadequate design, operation, or maintenance; and

(2) Repairs were made as expeditiously as possible when a violation occurred; and

(3) The frequency, amount, and duration of the violation (including any bypass) were minimized to the maximum extent practicable; and

(4) If the violation resulted from a bypass of control equipment or a process, then the bypass was unavoidable to prevent loss of life, personal injury, or severe property damage; and

(5) All possible steps were taken to minimize the impact of the violation on ambient air quality, the environment, and human health; and

(6) All emissions monitoring and control systems were kept in operation if at all possible, consistent with safety and good air pollution control practices; and

(7) All of the actions in response to the violation were documented by properly signed, contemporaneous operating logs; and

(8) At all times, the affected source was operated in a manner consistent with good practices for minimizing emissions; and

(9) A written root cause analysis has been prepared, the purpose of which is to determine, correct, and eliminate the primary causes of the malfunction and the violation resulting from the malfunction event at issue. The analysis shall also specify, using best monitoring methods and engineering judgment, the amount of any emissions that were the result of the malfunction.

(b) *Report.* The owner or operator seeking to assert an affirmative defense shall submit a written report to the Administrator with all necessary supporting documentation, that it has met the requirements set forth in paragraph (a) of this section. This affirmative defense report shall be included in the first periodic compliance, deviation report or excess emission report otherwise required after the initial occurrence of the violation of the relevant standard (which may be the end of any applicable averaging period). If such compliance, deviation report or excess emission report is due less than 45 days after the initial occurrence of the violation, the affirmative defense report may be included in the second compliance, deviation report or excess emission report due after the initial occurrence of the violation of the relevant standard.

■ 13. Section 63.1345 is revised to read as follows:

§ 63.1345 Emissions limits for affected sources other than kilns; clinker coolers; new and reconstructed raw material dryers.

The owner or operator of each new or existing raw material, clinker, or finished product storage bin; conveying system transfer point; bagging system; bulk loading or unloading system; raw and finish mills; and each existing raw material dryer, at a facility which is a major source subject to the provisions of this subpart must not cause to be discharged any gases from these affected sources which exhibit opacity in excess of 10 percent.

■ 14. Section 63.1346 is amended by:

■ a. Revising paragraph (a) introductory text;

■ b. Revising paragraph (a)(1);

■ c. Revising paragraphs (c) through (f); and

■ d. Adding paragraph (g)

The revisions read as follows:

§ 63.1346 Operating limits for kilns.

(a) The owner or operator of a kiln subject to a D/F emissions limitation under § 63.1343 must operate the kiln such that the temperature of the gas at the inlet to the kiln PM control device (PMCD) and alkali bypass PMCD, if applicable, does not exceed the applicable temperature limit specified in paragraph (b) of this section. The owner or operator of an in-line kiln/raw mill subject to a D/F emissions limitation under § 63.1343 must operate the in-line kiln/raw mill, such that:

(1) When the raw mill of the in-line kiln/raw mill is operating, the applicable temperature limit for the main in-line kiln/raw mill exhaust, specified in paragraph (b) of this section and established during the performance test when the raw mill was operating, is not exceeded, except during periods of startup and shutdown when the

temperature limit may be exceeded by no more than 10 percent.

* * * * *

(c) For an affected source subject to a D/F emissions limitation under § 63.1343 that employs sorbent injection as an emission control technique for D/F control, you must operate the sorbent injection system in accordance with paragraphs (c)(1) and (2) of this section.

(1) The rolling three-hour average activated sorbent injection rate must be equal to or greater than the sorbent injection rate determined in accordance with § 63.1349(b)(3)(vi).

(2) You must either:

(i) Maintain the minimum activated carbon injection carrier gas flow rate, as a rolling three-hour average, based on the manufacturer's specifications. These specifications must be documented in the test plan developed in accordance with § 63.7(c), or

(ii) Maintain the minimum activated carbon injection carrier gas pressure drop, as a rolling three-hour average, based on the manufacturer's specifications. These specifications must be documented in the test plan developed in accordance with § 63.7(c).

(d) Except as provided in paragraph (e) of this section, for an affected source subject to a D/F emissions limitation under § 63.1343 that employs carbon injection as an emission control technique you must specify and use the brand and type of sorbent used during the performance test until a subsequent performance test is conducted, unless the site-specific performance test plan contains documentation of key parameters that affect adsorption and the owner or operator establishes limits based on those parameters, and the limits on these parameters are maintained.

(e) For an affected source subject to a D/F emissions limitation under § 63.1343 that employs carbon injection as an emission control technique you may substitute, at any time, a different brand or type of sorbent provided that the replacement has equivalent or improved properties compared to the sorbent specified in the site-specific performance test plan and used in the performance test. The owner or operator must maintain documentation that the substitute sorbent will provide the same or better level of control as the original sorbent.

(f) No kiln may use as a raw material or fuel any fly ash where the mercury content of the fly ash has been increased through the use of activated carbon, or any other sorbent, unless the facility can demonstrate that the use of that fly ash will not result in an increase in mercury emissions over baseline emissions (i.e., emissions not using the fly ash). The facility has the burden of proving there has been no emissions increase over baseline. Once the kiln is in compliance with a mercury emissions limit specified in § 63.1343, this paragraph no longer applies.

(g) During periods of startup and shutdown you must meet the requirements listed in (g)(1) through (4) of this section.

(1) During startup you must use any one or combination of the following clean fuels: natural gas, synthetic natural gas, propane, distillate oil, synthesis gas (syngas), and ultra-low sulfur diesel (ULSD) until the kiln reaches a temperature of 1200 degrees Fahrenheit.

(2) Combustion of the primary kiln fuel may commence once the kiln temperature reaches 1200 degrees Fahrenheit.

(3) All air pollution control devices must be turned on and operating prior to combusting any fuel.

(4) You must keep records as specified in § 63.1355 during periods of startup and shutdown.

■ 15. Section 63.1347 is amended by revising paragraph (a)(1) to read as follows:

§ 63.1347 Operation and maintenance plan requirements.

(a) * * *

(1) Procedures for proper operation and maintenance of the affected source and air pollution control devices in order to meet the emissions limits and operating limits, including fugitive dust control measures for open clinker piles, of §§ 63.1343 through 63.1348. Your operations and maintenance plan must address periods of startup and shutdown;

* * * * *

■ 16. Section 63.1348 is amended by:

■ a. Revising paragraphs (a) introductory text and (a)(1) and (2);

■ b. Adding two sentences to paragraph (a)(3)(i);

■ c. Revising paragraph (a)(3)(ii);

■ d. Revising paragraphs (a)(3)(iii) and (iv);

■ e. Revising paragraphs (a)(4) through (8);

■ f. Revising paragraph (b); and

■ g. Revising paragraph (c)(2)(iv).

The revisions and additions read as follows:

§ 63.1348 Compliance requirements.

(a) *Initial Performance Test Requirements.* For an affected source subject to this subpart, you must demonstrate compliance with the emissions standards and operating limits by using the test methods and procedures in §§ 63.1349 and 63.7. Any cement kiln that has been subject to the requirements of subpart CCCC or subpart DDDD of 40 CFR Part 60, and is now electing to cease burning nonhazardous solid waste and become subject to this subpart, must meet all the initial compliance testing requirements each time it becomes subject to this subpart, even if it was previously subject to this subpart.

NOTE to paragraph (a): The first day of the 30 operating day performance test is the first day after the compliance date following completion of the field testing and data collection that demonstrates that the CPMS or CEMS has satisfied the relevant CPMS performance evaluation or CEMS performance specification (e.g., PS 2, 12A, or 12B) acceptance criteria. The performance test period is complete at the end of the 30th consecutive operating day. See § 63.1341 for definition of operating day and § 63.1348(b)(1) for the CEMS operating requirements. The source has the option of performing the compliance test earlier then the compliance date if desired.

(1) *PM Compliance.* If you are subject to limitations on PM emissions under § 63.1343(b), you must demonstrate compliance with the PM emissions standards by using the test methods and procedures in § 63.1349(b)(1).

(2) *Opacity Compliance.* If you are subject to the limitations on opacity under § 63.1345, you must demonstrate compliance with the opacity emissions standards by using the performance test methods and procedures in § 63.1349(b)(2). Use the maximum 6-minute average opacity exhibited during the performance test period to determine whether the affected source is in compliance with the standard.

(3) * * *

(i) * * * The owner or operator of a kiln with an in-line raw mill must demonstrate compliance by conducting separate performance tests while the raw mill is operating and while the raw mill is not operating. Determine the D/F TEQ concentration for each run and calculate the arithmetic average of the TEQ concentrations measured for the three runs to determine continuous compliance.

(ii) If you are subject to a D/F emissions limitation under § 63.1343(b), you must demonstrate compliance with the temperature operating limits specified in § 63.1346 by using the performance test methods and procedures in § 63.1349(b)(3)(ii) through (b)(3)(iv). Use the arithmetic average of the temperatures measured during the

three runs to determine the applicable temperature limit.

(iii) If activated carbon injection is used and you are subject to a D/F emissions limitation under § 63.1343(b), you must demonstrate compliance with the activated carbon injection rate operating limits specified in § 63.1346 by using the performance test methods and procedures in § 63.1349(b)(3)(v).

(iv) If activated carbon injection is used, you must also develop a carrier gas parameter (either the carrier gas flow rate or the carrier gas pressure drop) during the initial performance test and updated during any subsequent performance test conducted under § 63.1349(b)(3) that meets the requirements of § 63.1349(b)(3)(vi). Compliance is demonstrated if the system is maintained within +/- 5 percent accuracy during the performance test determined in accordance with the procedures and criteria submitted for review in your monitoring plan required in section 63.1350(p).

(4)(i) *THC Compliance.* If you are subject to limitations on THC emissions under § 63.1343(b), you must demonstrate compliance with the THC emissions standards by using the performance test methods and procedures in § 63.1349(b)(4)(i). You must use the average THC concentration obtained during the first 30 kiln operating days after the compliance date of this rule to determine initial compliance.

(ii) *Total Organic HAP Emissions Tests.* If you elect to demonstrate compliance with the total organic HAP emissions limit under § 63.1343(b) in lieu of the THC emissions limit, you must demonstrate compliance with the total organic HAP emissions standards by using the performance test methods and procedures in § 63.1349(b)(7.

(iii) If you are demonstrating initial compliance, you must conduct the separate performance tests as specified in § 63.1349(b)(7) while the raw mill of the inline kiln/raw mill is operating and while the raw mill of the inline kiln/raw mill is not operating.

(iv) The average total organic HAP concentration measured during the separate initial performance test specified by § 63.1349(b)(7) must be used to determine initial compliance.

(v) The average THC concentration measured during the initial performance test specified by § 63.1349(b)(4) must be used to determine the site-specific THC limit. Using the fraction of time the inline kiln/raw mill is on and the fraction of time that the inline kiln/raw mill is off, calculate this limit as a weighted average of the THC levels measured during raw mill on and raw mill off testing using one of the two approaches in § 63.1349(b)(7)(vii) or (viii) depending on the level of organic HAP measured during the compliance test.

(5) *Mercury Compliance.* If you are subject to limitations on mercury emissions in § 63.1343(b), you must demonstrate compliance with the mercury standards by using the performance test methods and procedures in § 63.1349(b)(5). You must demonstrate compliance by operating a mercury CEMS or a sorbent trap based CEMS. Compliance with the mercury emissions standard must be determined based on the first 30 operating days you operate a mercury CEMS or sorbent trap monitoring system after the compliance date of this rule.

(i) In calculating a 30 operating day emissions value using an integrating sorbent trap CEMS, assign the average Hg emissions concentration determined for an integrating period (e.g., 7 day sorbent trap monitoring system sample) to each relevant hour of the kiln operating days spanned by each integrated sample. Calculate the 30 kiln operating day emissions rate value using the assigned hourly Hg emissions concentrations and the respective flow and production rate values collected during the 30 kiln operating day performance test period. Depending on the duration of each integrated sampling period, you may not be able to calculate the 30 kiln operating day emissions value until several days after the end of the 30 kiln operating day performance test period.

(ii) For example, a sorbent trap monitoring system producing an integrated 7-day sample will provide Hg concentration data for each hour of the first 28 kiln operating days (i.e., four values spanning 7 days each) of a 30 operating day period. The Hg concentration values for the hours of the last 2 days of the 30 operating day period will not be available for calculating the emissions for the performance test period until at least five days after the end of the subject period.

(6) *HCl Compliance.* If you are subject to limitations on HCl emissions under § 63.1343(b), you must demonstrate initial compliance with the HCl standards by using the performance test methods and procedures in § 63.1349(b)(6).

(i) For an affected source that is equipped with a wet scrubber, tray tower or dry scrubber, you may demonstrate initial compliance by conducting a performance test as specified in § 63.1349(b)(6)(i). You must determine the HCl concentration for each run and calculate the arithmetic average of the concentrations measured for the three runs to determine compliance. You must also establish appropriate site-specific operational parameter limits.

(ii) For an affected source that is not equipped with a wet scrubber, tray tower or dry scrubber, you must demonstrate initial compliance by operating a CEMS as specified in § 63.1349(b)(6)(ii). You must use the average of the hourly HCl values obtained during the first 30 kiln operating days that occur after the compliance date of this rule to determine initial compliance.

(7) *Commingled Exhaust Requirements.* If the coal mill exhaust is commingled with kiln exhaust in a single stack, you may demonstrate compliance with the kiln emission limits by either:

(i) Performing required emissions monitoring and testing on the commingled coal mill and kiln exhaust, or

(ii) Perform required emission monitoring and testing of the kiln exhaust prior to the reintroduction of the coal mill exhaust, and also testing the kiln exhaust diverted to the coal mill. All emissions must be added together for all emission points, and must not exceed the limit per each pollutant as listed in S63.1343(b).

(b) *Continuous Monitoring Requirements.* You must demonstrate compliance with the emissions standards and operating limits by using the performance test methods and procedures in §§ 63.1350 and 63.8 for each affected source.

(1) *General Requirements.* (i) You must monitor and collect data according to § 63.1350 and the site-specific monitoring plan required by § 63.1350(p).

(ii) Except for periods of startup and shutdown, monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities (including, as applicable, calibration checks and required zero and span adjustments), you must operate the monitoring system and collect data at all required intervals at all times the affected source is operating.

(iii) You may not use data recorded during monitoring system malfunctions, repairs associated with monitoring system malfunctions, or required monitoring system quality assurance or control activities in calculations used to report emissions or operating levels. A monitoring system malfunction is any

sudden, infrequent, not reasonably preventable failure of the monitoring system to provide valid data. Monitoring system failures that are caused in part by poor maintenance or careless operation are not malfunctions. You must use all the data collected during all other periods in assessing the operation of the control device and associated control system.

(iv) *Clinker Production.* If you are subject to limitations on mercury emissions (lb/MM tons of clinker) under § 63.1343(b), you must determine the hourly production rate of clinker according to the requirements of § 63.1350(d).

(2) *PM Compliance.* If you are subject to limitations on PM emissions under § 63.1343(b), you must use the monitoring methods and procedures in § 63.1350(b) and (d).

(3) *Opacity Compliance.* If you are subject to the limitations on opacity under § 63.1345, you must demonstrate compliance using the monitoring methods and procedures in § 63.1350(f) based on the maximum 6-minute average opacity exhibited during the performance test period. You must initiate corrective actions within one hour of detecting visible emissions above the applicable limit.

(i) *COMS.* If you install a COMS in lieu of conducting the daily visible emissions testing, you must demonstrate compliance using a COMS such that it is installed, operated, and maintained in accordance with the requirements of § 63.1350(f)(4)(i).

(ii) Bag leak determination system (*BLDS).* If you install a BLDS on a raw mill or finish mill in lieu of conducting the daily visible emissions testing, you must demonstrate compliance using a BLDS that is installed, operated, and maintained in accordance with the requirements of § 63.1350(f)(4)(ii).

(4) *D/F Compliance.* If you are subject to a D/F emissions limitation under § 63.1343(b), you must demonstrate compliance using a CMS that is installed, operated and maintained to record the temperature of specified gas streams in accordance with the requirements of § 63.1350(g).

(5)(i) *Activated Carbon Injection Compliance.* If you use activated carbon injection to comply with the D/F emissions limitation under § 63.1343(b), you must demonstrate compliance using a CMS that is installed, operated, and maintained to record the rate of activated carbon injection in accordance with the requirements § 63.1350(h)(1).

(ii) If you use activated carbon injection to comply with the D/F emissions limitation under § 63.1343(b), you must demonstrate compliance using a CMS that is installed, operated and maintained to record the activated carbon injection system gas parameter in accordance with the requirements of § 63.1350(h)(2).

(6) THC Compliance. (i) If you are subject to limitations on THC emissions under § 63.1343(b), you must demonstrate compliance using the monitoring methods and procedures in § 63.1350(i) and (j).

(ii) THC must be measured either upstream of the coal mill or in the coal mill stack.

(7) Mercury Compliance. (i) If you are subject to limitations on mercury emissions in § 63.1343(b), you must demonstrate compliance using the monitoring methods and procedures in § 63.1350(k). If you use an integrated sorbent trap monitoring system to determine ongoing compliance, use the procedures described in § 63.1348(a)(5) to assign hourly mercury concentration values and to calculate rolling 30 operating day emissions rates. Since you assign the mercury concentration measured with the sorbent trap to each relevant hour respectively for each operating day of the integrated period, you may schedule the sorbent trap change periods to any time of the day (i.e., the sorbent trap replacement need not be scheduled at 12:00 midnight nor must the sorbent trap replacements occur only at integral 24-hour intervals).

(ii) Mercury must be measured either upstream of the coal mill or in the coal mill stack.

(8) *HCl Compliance.* If you are subject to limitations on HCl emissions under § 63.1343(b), you must demonstrate compliance using the performance test methods and procedures in § 63.1349(b)(6).

(i) For an affected source that is not equipped with a wet scrubber, tray tower or a dry sorbent injection system, you must demonstrate compliance using the monitoring methods and procedures in § 63.1350(l)(1).

(ii) For an affected source that is equipped with a wet scrubber, tray tower or a dry sorbent injection system, you may demonstrate compliance using the monitoring methods and procedures in § 63.1350(l)(2).

(iii) HCl may be measured either upstream of the coal mill or in the coal mill stack.

(iv) As an alternative to paragraph (b)(8)(ii) of this section, you may use an SO_2 CEMS to establish an SO_2 operating level during your initial and repeat HCl performance tests and monitor the SO_2 level using the procedures in § 63.1350(l)(3).

(9) Startup and Shutdown Compliance. In order to demonstrate continuous compliance during startup and shutdown, all air pollution control devices must be operating.

(c) * * *

(2) * * *

(iv) The performance test must be completed within 360 hours after the planned operational change period begins.

* * * * *

■ 17. Section 63.1349 is amended by:

■ a. Revising paragraph (a) introductory text;

■ b. Revising paragraph (b)(1);

■ c. Revising paragraph (b)(3) introductory text;

■ d. Revising paragraphs (b)(3)(v) and (vi);

■ e. Revising paragraphs (b)(4), (5), and (6);

■ f. Adding paragraph (b)(7) and (8); and

■ g. Revising paragraphs (c), (d)(1) introductory text, (d)(1)(ii), (d)(2), and (e).

The revisions and additions read as follows:

§ 63.1349 Performance testing requirements.

(a) You must document performance test results in complete test reports that contain the information required by paragraphs (a)(1) through (10) of this section, as well as all other relevant information. As described in § 63.7(c)(2)(i), you must make available to the Administrator prior to testing, if requested, the site-specific test plan to be followed during performance testing. For purposes of determining exhaust gas flow rate to the atmosphere from an alkali bypass stack or a coal mill stack, you must either install, operate, calibrate and maintain an instrument for continuously measuring and recording the exhaust gas flow rate according to the requirements in paragraphs § 63.1350(n)(1) through (10) of this subpart or use the maximum design exhaust gas flow rate. For purposes of determining the combined emissions from kilns equipped with an alkali bypass or that exhaust kiln gases to a coal mill that exhausts through a separate stack, instead of installing a CEMS on the alkali bypass stack or coal mill stack, you may use the results of the initial and subsequent performance test to demonstrate compliance with the relevant emissions limit.

* * * * *

(b)(1) *PM emissions tests.* The owner or operator of a kiln subject to limitations on PM emissions shall demonstrate initial compliance by conducting a performance test using Method 5 or Method 5I at appendix A–3 to part 60 of this chapter. You must

also monitor continuous performance through use of a PM continuous parametric monitoring system (PM CPMS).

(i) For your PM CPMS, you will establish a site-specific operating limit. If your PM performance test demonstrates your PM emission levels to be below 75 percent of your emission limit you will use the average PM CPMS value recorded during the PM compliance test, the milliamp equivalent of zero output from your PM CPMS, and the average PM result of your compliance test to establish your operating limit. If your PM compliance test demonstrates your PM emission levels to be at or above 75 percent of your emission limit you will use the average PM CPMS value recorded during the PM compliance test to establish your operating limit. You will use the PM CPMS to demonstrate continuous compliance with your operating limit. You must repeat the performance test annually and reassess and adjust the site-specific operating limit in accordance with the results of the performance test.

(A) Your PM CPMS must provide a 4–20 milliamp output and the establishment of its relationship to manual reference method measurements must be determined in units of milliamps.

(B) Your PM CPMS operating range must be capable of reading PM concentrations from zero to a level equivalent to three times your allowable emission limit. If your PM CPMS is an auto-ranging instrument capable of multiple scales, the primary range of the instrument must be capable of reading PM concentration from zero to a level equivalent to three times your allowable emission limit.

(C) During the initial performance test or any such subsequent performance test that demonstrates compliance with the PM limit, record and average all milliamp output values from the PM CPMS for the periods corresponding to the compliance test runs (e.g., average all your PM CPMS output values for three corresponding 2-hour Method 5I test runs).

(ii) Determine your operating limit as specified in paragraphs (b)(1)(iii) through (iv) of this section. If your PM performance test demonstrates your PM emission levels to be below 75 percent of your emission limit you will use the average PM CPMS value recorded during the PM compliance test, the milliamp equivalent of zero output from your PM CPMS, and the average PM result of your compliance test to establish your operating limit. If your PM compliance test demonstrates your PM emission levels to be at or above 75 percent of your emission limit you will use the average PM CPMS value recorded during the PM compliance test to establish your operating limit. You must verify an existing or establish a new operating limit after each repeated performance test. You must repeat the performance test at least annually and reassess and adjust the site-specific operating limit in accordance with the results of the performance test.

(iii) If the average of your three Method 5 or 5I compliance test runs is below 75 percent of your PM emission limit, you must calculate an operating limit by establishing a relationship of PM CPMS signal to PM concentration using the PM CPMS instrument zero, the average PM CPMS values corresponding to the three compliance test runs, and the average PM concentration from the Method 5 or 5I compliance test with the procedures in (a)(1)(iii)(A) through (D) of this section.

(A) Determine your PM CPMS instrument zero output with one of the following procedures.

(*1*) Zero point data for in-situ instruments should be obtained by removing the instrument from the stack and monitoring ambient air on a test bench.

(*2*) Zero point data for extractive instruments should be obtained by removing the extractive probe from the stack and drawing in clean ambient air.

(*3*) The zero point may also be established by performing manual reference method measurements when the flue gas is free of PM emissions or contains very low PM concentrations (e.g., when your process is not operating, but the fans are operating or your source is combusting only natural gas) and plotting these with the compliance data to find the zero intercept.

(*4*) If none of the steps in paragraphs (a)(1)(iii)(A)(*1*) through (*3*) of this section are possible, you must use a zero output value provided by the manufacturer.

(B) Determine your PM CPMS instrument average in milliamps, and the average of your corresponding three PM compliance test runs, using equation 3.

$$\bar{x} = \frac{1}{n}\sum_{i=1}^{n} X_1 , \bar{y} = \frac{1}{n}\sum_{i=1}^{n} Y_1 \qquad \text{(Eq. 3)}$$

Where:

X_1 = The PM CPMS data points for the three runs constituting the performance test.

Y_1 = The PM concentration value for the three runs constituting the performance test.

n = The number of data points.

(C) With your instrument zero expressed in milliamps, your three run average PM CPMS milliamp value, and your three run PM compliance test average, determine a relationship of lb/ton-clinker per milliamp with Equation 4.

$$R = \frac{Y_1}{(X_1 - z)} \qquad \text{(Eq. 4)}$$

Where:

R = The relative lb/ton-clinker per milliamp for your PM CPMS.

Y_1 = The three run average lb/ton-clinker PM concentration.

X_1 = The three run average milliamp output from you PM CPMS.

z = The milliamp equivalent of your instrument zero determined from (b)(1)(iii)(A).

(D) Determine your source specific 30-day rolling average operating limit using the lb/ton-clinker per milliamp value from Equation 4 in Equation 5, below. This sets your operating limit at the PM CPMS output value corresponding to 75 percent of your emission limit.

$$O_l = z + \frac{0.75(L)}{R} \quad \text{(Eq. 5)}$$

Where:

O_l = The operating limit for your PM CPMS on a 30-day rolling average, in milliamps.

L = Your source emission limit expressed in lb/ton clinker.

z = Your instrument zero in milliamps, determined from (1)(i).

R = The relative lb/ton-clinker per milliamp for your PM CPMS, from Equation 4.

(iv) If the average of your three PM compliance test runs is at or above 75 percent of your PM emission limit you must determine your operating limit by averaging the PM CPMS milliamp output corresponding to your three PM performance test runs that demonstrate compliance with the emission limit using Equation 6.

$$O_h = \frac{1}{n}\sum_{i=1}^{n} X_1 \quad \text{(Eq. 6)}$$

Where:

X_1 = The PM CPMS data points for all runs i.

n = The number of data points.

O_h = Your site specific operating limit, in milliamps.

(v) To determine continuous operating compliance, you must record the PM CPMS output data for all periods when the process is operating, and use all the PM CPMS data for calculations when the source is not out-of-control. You must demonstrate continuous compliance by using all quality-assured hourly average data collected by the PM CPMS for all operating hours to calculate the arithmetic average operating parameter in units of the operating limit (milliamps) on a 30 operating day rolling average basis, updated at the end of each new kiln operating day. Use Equation 7 to determine the 30 kiln operating day average.

$$30\text{kiln operating day} = \frac{\sum_{i=1}^{n} Hpv_i}{n} \quad \text{(Eq. 7)}$$

Where:

Hpvi = The hourly parameter value for hour i.

n = The number of valid hourly parameter values collected over 30 kiln operating days.

(vi) For each performance test, conduct at least three separate test runs under the conditions that exist when the affected source is operating at the highest load or capacity level reasonably expected to occur. Conduct each test run to collect a minimum sample volume of 2 dscm for determining compliance with a new source limit and 1 dscm for determining compliance with an existing source limit. Calculate the average of the results from three consecutive runs, including applicable sources as required by (D)(viii), to determine compliance. You need not determine the particulate matter collected in the impingers (''back half'') of the Method 5 or Method 5I particulate sampling train to demonstrate compliance with the PM standards of this subpart. This shall not preclude the permitting authority from requiring a determination of the ''back half'' for other purposes.

(vii) For PM performance test reports used to set a PM CPMS operating limit, the electronic submission of the test report must also include the make and model of the PM CPMS instrument, serial number of the instrument, analytical principle of the instrument (e.g. beta attenuation), span of the instruments primary analytical range, milliamp value equivalent to the instrument zero output, technique by which this zero value was determined, and the average milliamp signals corresponding to each PM compliance test run.

(viii) When there is an alkali bypass and/or an inline coal mill with a separate stack associated with a kiln, the main exhaust and alkali bypass and/or inline coal mill must be tested simultaneously and the combined emission rate of PM from the kiln and alkali bypass and/or inline coal mill must be computed for each run using Equation 8 of this section.

$$E_c = \frac{E_K + E_B + E_C}{P} \quad \text{(Eq. 8)}$$

Where:

E_C = Combined hourly emission rate of PM from the kiln and bypass stack and/or inline coal mill, lb/ton of kiln clinker production.

E_K = Hourly emissions of PM emissions from the kiln, lb.

E_B = Hourly PM emissions from the alkali bypass stack, lb.

E_C = Hourly PM emissions from the inline coal mill stack, lb.

P = Hourly clinker production, tons.

(ix) The owner or operator of a kiln with an in-line raw mill and subject to limitations on PM emissions shall demonstrate initial compliance by conducting separate performance tests while the raw mill is under normal operating conditions and while the raw mill is not operating.

* * * * *

(3) *D/F Emissions Tests.* If you are subject to limitations on D/F emissions under this subpart, you must conduct a performance test using Method 23 of appendix A–7 to part 60 of this chapter. If your kiln or in-line kiln/raw mill is equipped with an alkali bypass, you must conduct simultaneous performance tests of the kiln or in-line kiln/raw mill exhaust and the alkali bypass. You may conduct a performance test of the alkali bypass exhaust when the raw mill of the in-line kiln/raw mill is operating or not operating.

* * * * *

(v)(A) If sorbent injection is used for D/F control, you must record the rate of sorbent injection to the kiln exhaust, and where applicable, the rate of sorbent injection to the alkali bypass exhaust, continuously during the period of the Method 23 test in accordance with the conditions in § 63.1350(m)(9), and include the continuous injection rate record(s) in the performance test report. Determine the sorbent injection rate parameters in accordance with paragraphs (b)(3)(vi) of this section.

(B) Include the brand and type of sorbent used during the performance test in the performance test report.

(C) Maintain a continuous record of either the carrier gas flow rate or the carrier gas pressure drop for the duration of the performance test. If the carrier gas flow rate is used, determine, record, and maintain a record of the accuracy of the carrier gas flow rate monitoring system according to the procedures in appendix A to part 75 of this chapter. If the carrier gas pressure drop is used, determine, record, and maintain a record of the accuracy of the carrier gas pressure drop monitoring system according to the procedures in § 63.1350(m)(6).

(vi) Calculate the run average sorbent injection rate for each run and determine and include the average of the run average injection rates in the performance test report and determine the applicable injection rate limit in accordance with § 63.1346(c)(1).

(4) *THC emissions test.* (i) If you are subject to limitations on THC emissions, you must operate a CEMS in accordance with the requirements in § 63.1350(i). For the purposes of conducting the accuracy and quality assurance evaluations for CEMS, the THC span value (as propane) is 50 ppmvd and the reference method (RM) is Method 25A of appendix A to part 60 of this chapter.

(ii) Use the THC CEMS to conduct the initial compliance test for the first 30 kiln operating days of kiln operation after the compliance date of the rule. See 63.1348(a).

(iii) If kiln gases are diverted through an alkali bypass or to a coal mill and exhausted through a separate stack, you must calculate a kiln-specific THC limit using Equation 9:

$$Cks = \frac{(MACT\ Limit \times (Qab + Qcm + Qks)) - (Qab \times Cab) - (Qcm \times Ccm)}{Qks} \quad \text{((Eq. 9)}$$

Where:

Cks = Kiln stack concentration (ppmvd).
Qab = Alkali bypass flow rate (volume/hr).
Cab = Alkali bypass concentration (ppmvd).
Qcm = Coal mill flow rate (volume/hr).
Ccm = Coal mill concentration (ppmvd).
Qks = Kiln stack flow rate (volume/hr).

(iv) THC must be measured either upstream of the coal mill or the coal mill stack.

(v) Instead of conducting the performance test specified in paragraph (b)(4)of this section, you may conduct a performance test to determine emissions of total organic HAP by following the procedures in paragraphs (b)(7) of this section.

(5) *Mercury Emissions Tests.* If you are subject to limitations on mercury emissions, you must operate a mercury CEMS or a sorbent trap monitoring system in accordance with the requirements of § 63.1350(k). The initial compliance test must be based on the first 30 kiln operating days in which the affected source operates using a mercury CEMS or a sorbent trap monitoring system after the compliance date of the rule. See § 63.1348(a).

(i) If you are using a mercury CEMS or a sorbent trap monitoring system, you must install, operate, calibrate, and maintain an instrument for continuously measuring and recording the exhaust gas flow rate to the atmosphere according to the requirements in § 63.1350(k)(5).

(ii) Calculate the emission rate using Equation 10 of this section:

$$E_{30D} = k\,\frac{\sum_{i=1}^{n} C_i Q_i}{P} \quad \text{(Eq. 10)}$$

Where:

E_{30D} = 30-day rolling emission rate of mercury, lb/MM tons clinker.
C_i = Concentration of mercury for operating hour i, µg/scm.
Q_i = Volumetric flow rate of effluent gas for operating hour i, where C_i and Q_i are on the same basis (either wet or dry), scm/hr.
k = Conversion factor, 1 lb/454,000,000 µg.
n = Number of kiln operating hours in a 30 kiln operating day period.
P = 30 days of clinker production during the same time period as the mercury emissions measured, million tons.

(6) *HCl emissions tests.* For a source subject to limitations on HCl emissions you must conduct performance testing by one of the following methods:

(i)(A) If the source is equipped with a wet scrubber, tray tower or dry scrubber, you must conduct performance testing using Method 321 of appendix A to this part unless you have installed a CEMS that meets the requirements § 63.1350(l)(1). For kilns with inline raw mills, testing should be conducted for the raw mill on and raw mill off conditions.

(B) You must establish site specific parameter limits by using the CPMS required in § 63.1350(l)(1). For a wet scrubber or tray tower, measure and record the pressure drop across the scrubber and/or liquid flow rate and pH in intervals of no more than 15 minutes during the HCl test. Compute and record the 24-hour average pressure drop, pH, and average scrubber water flow rate for each sampling run in which the applicable emissions limit is met. For a dry scrubber, measure and record the sorbent injection rate in intervals of no more than 15 minutes during the HCl test. Compute and record the 24-hour average sorbent injection rate and average sorbent injection rate for each sampling run in which the applicable emissions limit is met.

(ii)(A) If the source is not controlled by a wet scrubber, tray tower or dry sorbent injection system, you must operate a CEMS in accordance with the requirements of § 63.1350(l)(1). See § 63.1348(a).

(B) The initial compliance test must be based on the 30 kiln operating days that occur after the compliance date of this rule in which the affected source operates using a HCl CEMS. Hourly HCl concentration data must be obtained according to § 63.1350(l).

(iii) As an alternative to paragraph (b)(6)(i)(B) of this section, you may choose to monitor SO_2 emissions using a CEMS in accordance with the

requirements of § 63.1350(l)(3). You must establish an SO_2 operating limit equal to the highest 1 hour average recorded during the HCl stack test. This operating limit will apply only for demonstrating HCl compliance.

(iv) If kiln gases are diverted through an alkali bypass or to a coal mill and exhausted through a separate stack, you must calculate a kiln-specific HCl limit using Equation 11:

$$Cks = \frac{(MACT\ Limit \times (Qab + Qcm + Qks)) - (Qab \times Cab) - (Qcm \times Ccm)}{Qks} \quad \text{(Eq. 11)}$$

Where:

Cks = Kiln stack concentration (ppmvd).
Qab = Alkali bypass flow rate (volume/hr).
Cab = Alkali bypass concentration (ppmvd).
Qcm = Coal mill flow rate (volume/hr).
Ccm = Coal mill concentration (ppmvd).
Qks = Kiln stack flow rate (volume/hr).

(7) *Total Organic HAP Emissions Tests.* Instead of conducting the performance test specified in paragraph (a)(4) of this section, you may conduct a performance test to determine emissions of total organic HAP by following the procedures in paragraphs (a)(7)(i) through (v) of this section.

(i) Use Method 320 of appendix A to this part, Method 18 of Appendix A of part 60, ASTM D6348–03 or a combination to determine emissions of total organic HAP. Each performance test must consist of three separate runs under the conditions that exist when the affected source is operating at the representative performance conditions in accordance with § 63.7(e). Each run must be conducted for at least 1 hour.

(ii) At the same time that you are conducting the performance test for total organic HAP, you must also determine a site-specific THC emissions limit by operating a THC CEMS in accordance with the requirements of § 63.1350(j). The duration of the performance test must be at least 3 hours and the average THC concentration (as calculated from the 1-minute averages) during the 3-hour test must be calculated. You must establish your THC operating limit and determine compliance with it according to paragraphs (a)(7)(vii)through (viii)of this section. It is permissible to extend the testing time of the organic HAP performance test if you believe extended testing is required to adequately capture THC variability over time.

(iii) If your source has an in-line kiln/raw mill you must use the fraction of time the raw mill is on and the fraction of time that the raw mill is off and calculate this limit as a weighted average of the THC levels measured during raw mill on and raw mill off testing.

(iv) If your organic HAP emissions are below 75 percent of the organic HAP standard and you determine your operating limit with paragraph (b)(7)(vii) of this section your THC CEMS must be calibrated and operated on a measurement scale no greater than 180 ppmvw, as carbon, or 60 ppmvw as propane.

(v) Your THC CEMS measurement scale must be capable of reading THC concentrations from zero to a level equivalent to two times your highest THC emissions average determined during your performance test, including mill on or mill off operation. **Note:** This may require the use of a dual range instrument to meet this requirement and paragraph (b)(7)(iv) of this section.

(vi) Determine your operating limit as specified in paragraphs (a)(7)(vii) and (viii) of this section. If your organic HAP performance test demonstrates your average organic HAP emission levels are below 75 percent of your emission limit (9 ppmv) you will use the average THC value recorded during the organic HAP performance test, and the average total organic HAP result of your performance test to establish your operating limit. If your organic HAP compliance test results demonstrate your average organic HAP emission levels are at or above 75 percent of your emission limit, your operating limit is established as the average THC value recorded during the organic HAP performance test. You must establish a new operating limit after each performance test. You must repeat the performance test no later than 30 months following your last performance test and reassess and adjust the site-specific operating limit in accordance with the results of the performance test.

(vii) If the average organic HAP results for your three Method 18 and/or Method 320 performance test runs are below 75 percent of your organic HAP emission limit, you must calculate an operating limit by establishing a relationship of THC CEMS signal to the organic HAP concentration using the average THC CEMS value corresponding to the three organic HAP compliance test runs and the average organic HAP total concentration from the Method 18 and/or Method 320 performance test runs with the procedures in (a)(7)(vii)(A) and (B) of this section.

(A) Determine the THC CEMS average values in ppmvw, and the average of your corresponding three total organic HAP compliance test runs, using Equation 12.

$$\bar{x} = \frac{1}{n}\sum_{i=1}^{n} X_i \ , \bar{y} = \frac{1}{n}\sum_{i=1}^{n} Y_i \quad \text{(Eq. 12)}$$

Where:

$\bar{x}$ = The THC CEMS average values in ppmvw.
Xi= The THC CEMS data points for all three runs i.
Yi= The sum of organic HAP concentrations for test runs i. and
n = The number of data points.

(B) You must use your three run average THC CEMS value, and your three run average organic HAP concentration from your three Method 18 and/or Method 320 compliance tests to determine the operating limit. Use equation 13 to determine your operating limit in units of ppmvw THC, as propane.

$$T_l = \left(\frac{9}{Y_1}\right) * X_1 \quad \text{(Eq. 13)}$$

Where:

T_1 = The 30-day operating limit for your THC CEMS, ppmvw.

Y_1 = The average organic HAP concentration from Eq. 12, ppmv.

X_1 = The average THC CEMS concentration from Eq. 12, ppmvw.

(viii) If the average of your three organic HAP performance test runs is at or above 75 percent of your organic HAP emission limit, you must determine your operating limit using Equation 14 by averaging the THC CEMS output values corresponding to your three organic HAP performance test runs that demonstrate compliance with the emission limit. If your new THC CEMS value is below your current operating limit, you may opt to retain your current operating limit, but you must still submit all performance test and THC CEMS data according to the reporting requirements in paragraph (d)(1) of this section.

$$T_h = \frac{1}{n}\sum_{i=1}^{n} X_1 , \qquad \text{(Eq. 14)}$$

Where:

X1 = The THC CEMS data points for all runs i.

Y1 = The organic HAP total value for runs i.

n = The number of data points.

T_h = Your site specific operating limit, in ppmvw THC.

(ix) If your kiln has an inline kiln/raw mill, you must conduct separate performance tests while the raw mill is operating (''mill on'') and while the raw mill is not operating (''mill off''). Using the fraction of time the raw mill is on and the fraction of time that the raw mill is off, calculate this limit as a weighted average of the THC levels measured during raw mill on and raw mill off compliance testing with Equation 15.

$$R=(y*t)+(x*(1-t)) \qquad \text{(Eq.15)}$$

Where:

R = Operating limit as THC, ppmvw.

y = Average THC CEMS value during mill on operations, ppmvw.

t = Percentage of operating time with mill on.

x = Average THC CEMS value during mill off operations, ppmvw.

(1-t) = Percentage of operating time with mill off.

(x) To determine continuous compliance with the THC operating limit, you must record the THC CEMS output data for all periods when the process is operating and the THC CEMS is not out-of-control. You must demonstrate continuous compliance by using all quality-assured hourly average data collected by the THC CEMS for all operating hours to calculate the arithmetic average operating parameter in units of the operating limit (ppmvw) on a 30 operating day rolling average basis, updated at the end of each new kiln operating day. Use Equation 16 to determine the 30 kiln operating day average.

$$30\text{kiln operating day} = \frac{\sum_{i=1}^{n} Hpv_i}{n} \qquad \text{(Eq. 16)}$$

Where:

Hpvi = The hourly parameter value for hour i, ppmvw.

n = The number of valid hourly parameter values collected over 30 kiln operating days.

(xi) Use EPA Method 18 or Method 320 of appendix A to part 60 of this chapter to determine organic HAP emissions. For each performance test, conduct at least three separate runs under the conditions that exist when the affected source is operating at the highest load or capacity level reasonably expected to occur. If your source has an in-line kiln/raw mill you must conduct three separate test runs with the raw mill on, and three separate runs under the conditions that exist when the affected source is operating at the highest load or capacity level reasonably expected to occur with the mill off. Conduct each Method 18 test run to collect a minimum target sample equivalent to three times the method detection limit. Calculate the average of the results from three runs to determine compliance.

(xii) If the THC level exceeds by 10 percent or more your site-specific THC emissions limit, you must

(A) As soon as possible but no later than 30 days after the exceedance, conduct an inspection and take corrective action to return the THC CEMS measurements to within the established value; and

(B) Within 90 days of the exceedance or at the time of the annual compliance test, whichever comes first, conduct another performance test to determine compliance with the organic HAP limit and to verify or re-establish your site-specific THC emissions limit.

(8) HCl Emissions Tests with SO_2 Monitoring. If you choose to monitor SO_2 emissions using a CEMS to demonstrate HCl compliance, follow the procedures in (b)(8)(i) through (ix) of this section and in accordance with the requirements of § 63.1350(l)(3). You must establish an SO_2 operating limit equal to the average of the SO_2 emissions recorded during the HCl stack test. This operating limit will apply only for demonstrating HCl compliance.

(i) Use Method 321 of appendix A to this part to determine emissions of HCl. Each performance test must consist of three separate runs under the conditions that exist when the affected source is operating at the representative performance conditions in accordance with § 63.7(e). Each run must be conducted for at least one hour.

(ii) At the same time that you are conducting the performance test for HCl, you must also determine a site-specific SO_2 emissions limit by

operating an SO_2 CEMS in accordance with the requirements of § 63.1350(l). The duration of the performance test must be three hours and the average SO_2 concentration (as calculated from the 1-minute averages) during the 3-hour test must be calculated. You must establish your SO_2 operating limit and determine compliance with it according to paragraphs (b)(8)(vii) and (viii)of this section.

(iii) If your source has an in-line kiln/raw mill you must use the fraction of time the raw mill is on and the fraction of time that the raw mill is off and calculate this limit as a weighted average of the SO_2 levels measured during raw mill on and raw mill off testing.

(iv) Your SO_2 CEMS must be calibrated and operated according to the requirements of § 60.63(f).

(v) Your SO_2 CEMS measurement scale must be capable of reading SO_2 concentrations consistent with the requirements of § 60.63(f), including mill on or mill off operation.

(vi) If your kiln has an inline kiln/raw mill, you must conduct separate performance tests while the raw mill is operating (''mill on'') and while the raw mill is not operating (''mill off''). Using the fraction of time the raw mill is on and the fraction of time that the raw mill is off, calculate this limit as a weighted average of the THC levels measured during raw mill on and raw mill off compliance testing with Equation 17.

$$R=(y*t)+x*(t-1) \qquad \text{(Eq. 17)}$$

Where:

R = Operating limit as SO_2, ppmvw.

y = Average SO_2 CEMS value during mill on operations, ppmvw.

t = Percentage of operating time with mill on, expressed as a decimal.

x = Average SO_2 CEMS value during mill off operations, ppmvw.

t − 1 = Percentage of operating time with mill off, expressed as a decimal.

(vii) To determine continuous compliance with the SO_2 operating limit, you must record the SO_2 CEMS output data for all periods when the process is operating and the SO_2 CEMS is not out-of-control. You must demonstrate continuous compliance by using all quality-assured hourly average data collected by the SO_2 CEMS for all operating hours to calculate the arithmetic average operating parameter in units of the operating limit (ppmvw) on a 30 operating day rolling average basis, updated at the end of each new kiln operating day. Use Equation 18 to determine the 30 kiln operating day average.

$$30\text{kiln operating day} = \frac{\sum_{i=1}^{n} Hpv_i}{n} \qquad \text{(Eq. 18)}$$

Where:

Hpvi = The hourly parameter value for hour i, ppmvw.

n = The number of valid hourly parameter values collected over 30 kiln operating days.

(viii) Use EPA Method 321 of appendix A to part 60 of this chapter to determine HCl emissions. For each performance test, conduct at least three separate runs under the conditions that exist when the affected source is operating at the highest load or capacity level reasonably expected to occur. If your source has an in-line kiln/raw mill you must conduct three separate test runs with the raw mill on, and three separate runs under the conditions that exist when the affected source is operating at the highest load or capacity level reasonably expected to occur with the mill off.

(ix) If the SO_2 level exceeds by 10 percent or more your site-specific SO_2 emissions limit, you must

(A) As soon as possible but no later than 30 days after the exceedance, conduct an inspection and take corrective action to return the SO_2 CEMS measurements to within the established value. and

(B) Within 90 days of the exceedance or at the time of the annual compliance test, whichever comes first, conduct another performance test to determine compliance with the HCl limit and to verify or re-establish your site-specific SO_2 emissions limit.

(c) *Performance Test Frequency.* Except as provided in § 63.1348(b), performance tests are required at regular intervals for affected sources that are subject to a dioxin, organic HAP or HCl emissions limit and must be repeated every 30 months except for pollutants where that specific pollutant is monitored using CEMS. Tests for PM are repeated every 12 months.

(d) *Performance Test Reporting Requirements.* (1) You must submit the information specified in paragraphs (d)(1) and (2) of this section no later than 60 days following the initial performance test. All reports must be signed by a responsible official.

* * * * *

(ii) The values for the site-specific operating limits or parameters established pursuant to paragraphs (b)(1), (3), (6), and (7) of this section, as applicable, and a description, including sample calculations, of how the operating parameters were established during the initial performance test.

(2) As of December 31, 2011 and within 60 days after the date of completing each performance evaluation or test, as defined in § 63.2, conducted to demonstrate compliance with any standard covered by this subpart, you must submit the relative accuracy test audit data and performance test data, except opacity data, to the EPA by successfully submitting the data electronically to the EPA's Central Data Exchange (CDX) by using the Electronic Reporting Tool(ERT) (see *http://www.epa.gov/ttn/chief/ert/ert_tool.html/*).

(e) *Conditions of performance tests.* Conduct performance tests under such conditions as the Administrator specifies to the owner or operator based on representative performance of the affected source for the period being tested. Upon request, you must make available to the Administrator such records as may be necessary to determine the conditions of performance tests.

■ 18. Section 63.1350 is amended by:

■ a. Revising paragraphs (a) through (d);

■ b. Revising paragraph (f) introductory text;

■ c. Revising paragraphs (f)(1)(iv) through (f)(1)(vi);
■ d. Revising paragraphs (f)(2)(i) and (f)(2)(iii);
■ e. Revising paragraphs (f)(3) and (f)(4);
■ f. Revising paragraph (g)(1) introductory text;
■ g. Revising paragraphs (g)(2) and (g)(4);
■ h. Revising paragraph (h)(1)(ii);
■ i. Revising paragraphs (i)(1) and (i)(2);
■ j. Revising paragraph (k);
■ k. Revising paragraph (l);
■ l. Revising paragraph (m) introductory text;
■ m. Revising paragraphs (m)(3) and (m)(7)(i);
■ n. Revising introductory text for paragraphs (m)(9) and (m) (10);
■ o. Revising paragraph (m)(10)(i) through (m)(10)(vii), and paragraph (m)(11)(v);
■ p. Revising introductory text for paragraphs (n), (o), and (p);
■ q. Removing and reserving paragraph (n)(3); and
■ r. Revising introductory text for paragraphs (p)(1), (p)(2), and (p)(5).

The revisions and additions read as follows:

§ 63.1350 Monitoring requirements.

(a)(1) Following the compliance date, the owner or operator must demonstrate compliance with this subpart on a continuous basis by meeting the requirements of this section.

(2) All continuous monitoring data for periods of startup and shutdown must be compiled and averaged separately from data gathered during other operating periods.

(3) For each existing unit that is equipped with a CMS, maintain the average emissions or the operating parameter values within the operating parameter limits established through performance tests.

(4) Any instance where the owner or operator fails to comply with the continuous monitoring requirements of this section is a violation.

(b) *PM monitoring requirements.* (1)(i) *PM CPMS.* You will use a PM CPMS to establish a site-specific operating limit corresponding to the results of the performance test demonstrating compliance with the PM limit. You will conduct your performance test using Method 5 or Method 5I at appendix A–3 to part 60 of this chapter. You will use the PM CPMS to demonstrate continuous compliance with this operating limit. You must repeat the performance test annually and reassess and adjust the site-specific operating limit in accordance with the results of the performance test using the procedures in § 63.1349(b)(1) (i) through (vi) of this subpart. You must also repeat the test if you change the analytical range of the instrument, or if you replace the instrument itself or any principle analytical component of the instrument that would alter the relationship of output signal to in-stack PM concentration.

(ii) To determine continuous compliance, you must use the PM CPMS output data for all periods when the process is operating and the PM CPMS is not out-of-control. You must demonstrate continuous compliance by using all quality-assured hourly average data collected by the PM CPMS for all operating hours to calculate the arithmetic average operating parameter in units of the operating limit (milliamps) on a 30 operating day rolling average basis, updated at the end of each new kiln operating day.

(iii) For any exceedance of the 30 process operating day PM CPMS average value from the established operating parameter limit, you must:

(A) Within 48 hours of the exceedance, visually inspect the APCD;

(B) If inspection of the APCD identifies the cause of the exceedance, take corrective action as soon as possible and return the PM CPMS measurement to within the established value; and

(C) Within 30 days of the exceedance or at the time of the annual compliance test, whichever comes first, conduct a PM emissions compliance test to determine compliance with the PM emissions limit and to verify or re-establish the PM CPMS operating limit within 45 days. You are not required to conduct additional testing for any exceedances that occur between the time of the original exceedance and the PM emissions compliance test required under this paragraph.

(iv) PM CPMS exceedances leading to more than four required performance tests in a 12-month process operating period (rolling monthly) constitute a presumptive violation of this subpart.

(2) [Reserved]

(c) [Reserved]

(d) *Clinker production monitoring requirements.* In order to determine clinker production, you must:

(1) Determine hourly clinker production by one of two methods:

(i) Install, calibrate, maintain, and operate a permanent weigh scale system to measure and record weight rates in tons-mass per hour of the amount of clinker produced. The system of measuring hourly clinker production must be maintained within ±5 percent accuracy, or

(ii) Install, calibrate, maintain, and operate a permanent weigh scale system to measure and record weight rates in tons-mass per hour of the amount of feed to the kiln. The system of measuring feed must be maintained within ±5 percent accuracy. Calculate your hourly clinker production rate using a kiln-specific feed to clinker ratio based on reconciled clinker production determined for accounting purposes and recorded feed rates. Update this ratio monthly. Note that if this ratio changes at clinker reconciliation, you must use the new ratio going forward, but you do not have to retroactively change clinker production rates previously estimated.

(iii) [Reserved]

(2) Determine, record, and maintain a record of the accuracy of the system of measuring hourly clinker production (or feed mass flow if applicable) before initial use (for new sources) or by the effective compliance date of this rule (for existing sources). During each quarter of source operation, you must determine, record, and maintain a record of the ongoing accuracy of the system of measuring hourly clinker production (or feed mass flow).

(3) If you measure clinker production directly, record the daily clinker production rates; if you measure the kiln feed rates and calculate clinker production, record the hourly kiln feed and clinker production rates.

(4) Develop an emissions monitoring plan in accordance with paragraphs (p)(1) through (p)(4) of this section.

* * * * *

(f) *Opacity Monitoring Requirements.* If you are subject to a limitation on opacity under § 63.1345, you must conduct required opacity monitoring in accordance with the provisions of paragraphs (f)(1)(i) through (vii) of this section and in accordance with your monitoring plan developed under § 63.1350(p). You must also develop an opacity monitoring plan in accordance with paragraphs (p)(1) through (4) and paragraph (o)(5), if applicable, of this section.

(1) * * *

(iv) If visible emissions are observed during any Method 22 performance test, of appendix A–7 to part 60 of this chapter, you must conduct 30 minutes of opacity observations, recorded at 15-second intervals, in accordance with Method 9 of appendix A–4 to part 60 of this chapter. The Method 9 performance test, of appendix A–4 to part 60 of this chapter, must begin within 1 hour of any observation of visible emissions.

(v) Any totally enclosed conveying system transfer point, regardless of the location of the transfer point is not required to conduct Method 22 visible emissions monitoring under this

paragraph. The enclosures for these transfer points must be operated and maintained as total enclosures on a continuing basis in accordance with the facility operations and maintenance plan.

(vi) If any partially enclosed or unenclosed conveying system transfer point is located in a building, you must conduct a Method 22 performance test, of appendix A–7 to part 60 of this chapter, according to the requirements of paragraphs (f)(1)(i) through (iv) of this section for each such conveying system transfer point located within the building, or for the building itself, according to paragraph (f)(1)(vii) of this section.

* * * * *

(2)(i) For a raw mill or finish mill, you must monitor opacity by conducting daily visible emissions observations of the mill sweep and air separator PM control devices (PMCD) of these affected sources in accordance with the procedures of Method 22 of appendix A–7 to part 60 of this chapter. The duration of the Method 22 performance test must be 6 minutes.

* * * * *

(iii) If visible emissions are observed during the follow-up Method 22 performance test required by paragraph (f)(2)(ii) of this section from any stack from which visible emissions were observed during the previous Method 22 performance test required by paragraph (f)(2)(i) of the section, you must then conduct an opacity test of each stack from which emissions were observed during the follow up Method 22 performance test in accordance with Method 9 of appendix A–4 to part 60 of this chapter. The duration of the Method 9 test must be 30 minutes.

(3) If visible emissions are observed during any Method 22 visible emissions test conducted under paragraphs (f)(1) or (2) of this section, you must initiate, within one-hour, the corrective actions specified in your operation and maintenance plan as required in § 63.1347.

(4) The requirements under paragraph (f)(2) of this section to conduct daily Method 22 testing do not apply to any specific raw mill or finish mill equipped with a COMS or BLDS.

(i) If the owner or operator chooses to install a COMS in lieu of conducting the daily visible emissions testing required under paragraph (f)(2) of this section, then the COMS must be installed at the outlet of the PM control device of the raw mill or finish mill and the COMS must be installed, maintained, calibrated, and operated as required by the general provisions in subpart A of this part and according to PS–1 of appendix B to part 60 of this chapter.

(ii) If you choose to install a BLDS in lieu of conducting the daily visible emissions testing required under paragraph (f)(2) of this section, the requirements in paragraphs (m)(1) through (m)(4), (m)(10) and (m)(11) of this section apply.

(g) * * *

(1) You must install, calibrate, maintain, and continuously operate a CMS to record the temperature of the exhaust gases from the kiln and alkali bypass, if applicable, at the inlet to, or upstream of, the kiln and/or alkali bypass PMCDs.

* * * * *

(2) You must monitor and continuously record the temperature of the exhaust gases from the kiln and alkali bypass, if applicable, at the inlet to the kiln and/or alkali bypass PMCD.

* * * * *

(4) Calculate the rolling three-hour average temperature using the average of 180 successive one-minute average temperatures. See § 63.1349(b)(3).

* * * * *

(h) * * *

(1) * * *

(ii) Each hour, calculate the three-hour rolling average activated carbon injection rate for the previous three hours of process operation. See § 63.1349(b)(3).

* * * * *

(i) * * *

(1) You must install, operate, and maintain a THC continuous emission monitoring system in accordance with Performance Specification 8A of appendix B to part 60 of this chapter and comply with all of the requirements for continuous monitoring systems found in the general provisions, subpart A of this part. The owner or operator must operate and maintain each CEMS according to the quality assurance requirements in Procedure 1 of appendix F in part 60 of this chapter.

(2) Performance tests on alkali bypass and coal mill stacks must be conducted using Method 25A in appendix A to 40 CFR part 60 and repeated annually.

* * * * *

(k) *Mercury Monitoring Requirements.* If you have a kiln subject to an emissions limitation on mercury emissions, you must install and operate a mercury continuous emissions monitoring system (Hg CEMS) in accordance with Performance Specification 12A (PS 12A) of appendix B to part 60 of this chapter or an integrated sorbent trap monitoring system in accordance with Performance Specification 12B (PS 12B) of appendix B to part 60 of this chapter. You must monitor mercury continuously according to paragraphs (k)(1) through (5) of this section. You must also develop an emissions monitoring plan in accordance with paragraphs (p)(1) through (4) of this section.

(1) You must use a span value for any Hg CEMS that represents the mercury concentration corresponding to approximately two times the emissions standard and may be rounded up to the nearest multiple of 5 μg/m³ of total mercury or higher level if necessary to include Hg concentrations which may occur (excluding concentrations during in-line raw ''mill off'' operation). As specified in PS 12A, Section 6.1.1, the data recorder output range must include the full range of expected Hg concentration values which would include those expected during ''mill off'' conditions. Engineering judgments made and calculations used to determine the corresponding span concentration from the emission standard shall be documented in the site-specific monitoring plan and associated records.

(2) In order to quality assure data measured above the span value, you must use one of the two options in paragraphs (k)(2)(i) and (ii) of this section.

(i) Include a second span that encompasses the Hg emission concentrations expected to be encountered during ''mill off'' conditions. This second span may be rounded to a multiple of 5 μg/m³ of total mercury. The requirements of PS 12A, shall be followed for this second span with the exception that a RATA with the mill off is not required.

(ii) Quality assure any data above the span value established in paragraph (k)(1) of this section using the following procedure. Any time two consecutive one-hour average measured concentration of Hg exceeds the span value you must, within 24 hours before or after, introduce a higher, ''above span'' Hg reference gas standard to the Hg CEMS. The ''above span'' reference gas must meet the requirements of PS 12A, Section 7.1, must be of a concentration level between 50 and 150 percent of the highest hourly concentration measured during the period of measurements above span, and must be introduced at the probe. Record and report the results of this procedure as you would for a daily calibration. The ''above span'' calibration is successful if the value measured by the Hg CEMS is within 20 percent of the certified value of the reference gas. If the value measured by the Hg CEMS exceeds 20 percent of the

certified value of the reference gas, then you must normalize the one-hour average stack gas values measured above the span during the 24-hour period preceding or following the ''above span'' calibration for reporting based on the Hg CEMS response to the reference gas as shown in equation 19:

$$\frac{\text{Certified reference gas value}}{\text{Measured value of reference gas}} \times \text{Measured stack gas result} = \text{Normalized stack gas result} \quad \text{(Eq. 19)}$$

Only one 'above span' calibration is needed per 24 hour period.

(3) You must operate and maintain each Hg CEMS or an integrated sorbent trap monitoring system according to the quality assurance requirements in Procedure 5 of appendix F to part 60 of this chapter. During the RATA of integrated sorbent trap monitoring systems required under Procedure 5, you may apply the appropriate exception for sorbent trap section 2 breakthrough in (k)(3)(i) through (iv) of this section:

(i) For stack Hg concentrations >1 μg/dscm, ≤10% of section 1 mass;

(ii) For stack Hg concentrations ≤1 μg/dscm and >0.5 μg/dscm, ≤20% of section 1 mass;

(iii) For stack Hg concentrations ≤0.5 μg/dscm and >0.1 μg/dscm, ≤50% of section 1 mass; and

(iv) For stack Hg concentrations ≤0.1 μg/dscm, no breakthrough criterion assuming all other QA/QC specifications are met.

(4) Relative accuracy testing of mercury monitoring systems under PS 12A, PS 12B, or Procedure 5 must be conducted at normal operating conditions. If a facility has an inline raw mill, the testing must occur with the raw mill on.

(5) If you use a Hg CEMS or an integrated sorbent trap monitoring system, you must install, operate, calibrate, and maintain an instrument for continuously measuring and recording the exhaust gas flow rate to the atmosphere according to the requirements in paragraphs (n)(1) through (10) of this section. If kiln gases are diverted through an alkali bypass or to a coal mill and exhausted through separate stacks, you must account for the mercury emitted from those stacks by following the procedures in (k)(5)(i) through (iv) of this section:

(i) Develop a mercury hourly mass emissions rate by conducting annual performance tests using Method 29, or Method 30B, to measure the concentration of mercury in the gases exhausted from the alkali bypass and coal mill.

(ii) On a continuous basis, determine the mass emissions of mercury in lb/hr from the alkali bypass and coal mill exhausts by using the mercury hourly emissions rate, the exhaust gas flow rate and hourly mercury emission rate to calculate hourly mercury emissions in lb/hr.

(iii) Sum the hourly mercury emissions from the kiln, alkali bypass and coal mill to determine total mercury emissions. Using hourly clinker production, calculate the hourly emissions rate in pounds per ton of clinker to determine your 30 day rolling average.

(iv) If mercury emissions from the coal mill are below the method detection limit for two consecutive annual performance tests, you may reduce the frequency of the performance tests of coal mills to once every 30 months. If the measured mercury concentration exceeds the method detection limit, you must revert to testing annually until two consecutive annual tests are below the method detection limit.

(6) If you operate an integrated sorbent trap monitoring system conforming to PS 12B, you may use a monitoring period at least 24 hours but no longer than 168 hours in length. You should use a monitoring period that is a multiple of 24 hours (except during relative accuracy testing as allowed in PS 12B).

(l) *HCl Monitoring Requirements.* If you are subject to an emissions limitation on HCl emissions in § 63.1343, you must monitor HCl emissions continuously according to paragraph (l)(1) or (2) and paragraphs (m)(1) through (4) of this section or, if your kiln is controlled using a wet or dry scrubber or tray tower, you alternatively may parametrically monitor SO_2 emissions continuously according to paragraph (l)(3) of this section. You must also develop an emissions monitoring plan in accordance with paragraphs (p)(1) through (4) of this section.

(1) If you monitor compliance with the HCl emissions limit by operating an HCl CEMS, you must do so in accordance with Performance Specification 15 (PS 15) of appendix B to part 60 of this chapter, or, upon promulgation, in accordance with any other performance specification for HCl CEMS in appendix B to part 60 of this chapter. You must operate, maintain, and quality assure a HCl CEMS installed and certified under PS 15 according to the quality assurance requirements in Procedure 1 of appendix F to part 60 of this chapter except that the Relative Accuracy Test Audit requirements of Procedure 1 must be replaced with the validation requirements and criteria of sections 11.1.1 and 12.0 of PS 15. If you install and operate an HCl CEMS in accordance with any other performance specification for HCl CEMS in appendix B to part 60 of this chapter, you must operate, maintain and quality assure the HCl CEMS using the procedure of appendix F to part 60 of this chapter applicable to the performance specification. You must use Method 321 of appendix A to part 63 of this chapter as the reference test method for conducting relative accuracy testing. The span value and calibration requirements in paragraphs (l)(1)(i) and (ii) of this section apply to HCl CEMS other than those installed and certified under PS 15.

(i) You must use a span value for any HCl CEMS that represents the intended upper limit of the HCl concentration measurement range during normal inline raw ''mill on'' operation. The span value should be a concentration equivalent to approximately two times the emissions standard and it may be rounded to the nearest multiple of 5 ppm of HCl. The HCl CEMS data recorder output range must include the full range of expected HCl concentration values which would include those expected during ''mill off'' conditions. Engineering judgments made and calculations used to determine the corresponding span concentration from the emission standard shall be documented in the site-specific monitoring plan and associated records.

(ii) In order to quality assure data measured above the span value, you must use one of the two options in paragraphs (l)(1)(ii)(A) and (B) of this section.

(A) Include a second span that encompasses the HCl emission concentrations expected to be

encountered during ''mill off'' conditions. This second span may be rounded to a multiple of 5 μg/m³ of total HCl. The requirements of the appropriate HCl monitor performance specification, shall be followed for this second span with the exception that a RATA with the mill off is not required.

(B) Quality assure any data above the span value established in paragraph (1)(1)(i) of this section using the following procedure. Any time the average measured concentration of HCl exceeds or is expected to exceed the span value for greater than two hours you must, within a period 24 hours before or after the 'above span' period, introduce a higher, 'above span' HCl reference gas standard to the HCl CEMS. The 'above span' reference gas must meet the requirements of the applicable performance specification and be of a concentration level between 50 and 100 percent of the highest hourly concentration measured during the period of measurements above span, and must be introduced at the probe. Record and report the results of this procedure as you would for a daily calibration. The 'above span' calibration is successful if the value measured by the HCl CEMS is within 20 percent of the certified value of the reference gas. If the value measured by the HCl CEMS is not within 20 percent of the certified value of the reference gas, then you must normalize the stack gas values measured above span as described in paragraph (l)(1)(ii)(C) below. If the 'above span' calibration is conducted during the period when measured emissions are above span and there is a failure to collect the required minimum number of data points in an hour due to the calibration duration, then you must determine the emissions average for that missed hour as the average of hourly averages for the hour preceding the missed hour and the hour following the missed hour.

(C) In the event that the 'above span' calibration is not successful (i.e., the HCl CEMS measured value is not within 20 percent of the certified value of the reference gas), then you must normalize the one-hour average stack gas values measured above the span during the 24-hour period preceding or following the 'above span' calibration for reporting based on the HCl CEMS response to the reference gas as shown in Equation 20:

$$\frac{\text{Certified reference gas value}}{\text{Measured value of reference gas}} \times \text{Measured stack gas result} = \text{Normalized stack gas result} \qquad \text{(Eq. 20)}$$

Only one 'above span' calibration is needed per 24-hour period.

(2) Install, operate, and maintain a CMS to monitor wet scrubber or tray tower parameters, as specified in paragraphs (m)(5) and (7) of this section, and dry scrubber, as specified in paragraph (m)(9) of this section.

(3) If the source is equipped with a wet or dry scrubber or tray tower, and you choose to monitor SO_2 emissions, monitor SO_2 emissions continuously according to the requirements of § 60.63(e) through (f) of part 60 subpart F of this chapter. If SO_2 levels increase above the 30-day rolling average SO_2 operating limit established during your performance test, you must:

(i) As soon as possible but no later than 48 hours after you exceed the established SO_2 value conduct an inspection and take corrective action to return the SO_2 emissions to within the operating limit; and

(ii) Within 60 days of the exceedance or at the time of the next compliance test, whichever comes first, conduct an HCl emissions compliance test to determine compliance with the HCl emissions limit and to verify or re-establish the SO_2 CEMS operating limit.

(m) *Parameter Monitoring Requirements.* If you have an operating limit that requires the use of a CMS, you must install, operate, and maintain each continuous parameter monitoring system (CPMS) according to the procedures in paragraphs (m)(1) through (4) of this section by the compliance date specified in § 63.1351. You must also meet the applicable specific parameter monitoring requirements in paragraphs (m)(5) through (11) that are applicable to you.

* * * * *

(3) Determine the 1-hour block average of all recorded readings.

* * * * *

(7) * * *

(i) Locate the pH sensor in a position that provides a representative measurement of wet scrubber or tray tower effluent pH.

* * * * *

(9) *Mass Flow Rate (for Sorbent Injection) Monitoring Requirements.* If you have an operating limit that requires the use of equipment to monitor sorbent injection rate (*e.g.,* weigh belt, weigh hopper, or hopper flow measurement device), you must meet the requirements in paragraphs (m)(9)(i) through (iii) of this section. These requirements also apply to the sorbent injection equipment of a dry scrubber.

* * * * *

(10) *Bag leak detection monitoring requirements.* If you elect to use a fabric filter bag leak detection system to comply with the requirements of this subpart, you must install, calibrate, maintain, and continuously operate a BLDS as specified in paragraphs (m)(10)(i) through (viii) of this section.

(i) You must install and operate a BLDS for each exhaust stack of the fabric filter.

(ii) Each BLDS must be installed, operated, calibrated, and maintained in a manner consistent with the manufacturer's written specifications and recommendations and in accordance with the guidance provided in EPA–454/R–98–015, September 1997.

(iii) The BLDS must be certified by the manufacturer to be capable of detecting PM emissions at concentrations of 10 or fewer milligrams per actual cubic meter.

(iv) The BLDS sensor must provide output of relative or absolute PM loadings.

(v) The BLDS must be equipped with a device to continuously record the output signal from the sensor.

(vi) The BLDS must be equipped with an alarm system that will alert an operator automatically when an increase in relative PM emissions over a preset level is detected. The alarm must be located such that the alert is detected and recognized easily by an operator.

(vii) For positive pressure fabric filter systems that do not duct all compartments of cells to a common stack, a BLDS must be installed in each baghouse compartment or cell.

* * * * *

(11) * * *

(v) Cleaning the BLDS probe or otherwise repairing the BLDS; or

* * * * *

(n) *Continuous Flow Rate Monitoring System.* You must install, operate, calibrate, and maintain instruments, according to the requirements in

paragraphs (n)(1) through (10) of this section, for continuously measuring and recording the stack gas flow rate to allow determination of the pollutant mass emissions rate to the atmosphere from sources subject to an emissions limitation that has a pounds per ton of clinker unit.

* * * * *

(o) *Alternate Monitoring Requirements Approval.* You may submit an application to the Administrator for approval of alternate monitoring requirements to demonstrate compliance with the emission standards of this subpart, except for emission standards for THC, subject to the provisions of paragraphs (o)(1) through (6) of this section.

* * * * *

(p) *Development and Submittal (Upon Request) of Monitoring Plans.* If you demonstrate compliance with any applicable emissions limit through performance stack testing or other emissions monitoring, you must develop a site-specific monitoring plan according to the requirements in paragraphs (p)(1) through (4) of this section. This requirement also applies to you if you petition the EPA Administrator for alternative monitoring parameters under paragraph (o) of this section and § 63.8(f). If you use a BLDS, you must also meet the requirements specified in paragraph (p)(5) of this section.

(1) For each CMS required in this section, you must develop, and submit to the permitting authority for approval upon request, a site-specific monitoring plan that addresses paragraphs (p)(1)(i) through (iii) of this section. You must submit this site-specific monitoring plan, if requested, at least 30 days before your initial performance evaluation of your CMS.

* * * * *

(2) In your site-specific monitoring plan, you must also address paragraphs (p)(2)(i) through (iii) of this section.

* * * * *

(5) *BLDS Monitoring Plan.* Each monitoring plan must describe the items in paragraphs (p)(5)(i) through (v) of this section. At a minimum, you must retain records related to the site-specific monitoring plan and information discussed in paragraphs (m)(1) through (4), (m)(10) and (11) of this section for a period of 5 years, with at least the first 2 years on-site;

* * * * *

■ 19. Section 63.1351 is amended by revising paragraphs (c) and (d) and adding paragraph (e) to read as follows:

§ 63.1351 Compliance dates.

* * * * *

(c) The compliance date for existing sources for all the requirements that became effective on February 12, 2013, except for the open clinker pile requirements will be September 9, 2015.

(d) The compliance date for new sources is February 12, 2013, or startup, whichever is later.

(e) The compliance date for existing sources with the requirements for open clinker storage piles in § 63.1343(c) is February 12, 2014.

■ 20. Section 63.1352 is amended by revising paragraph (b) to read as follows:

§ 63.1352 Additional test methods.

* * * * *

(b) Owners or operators conducting tests to determine the rates of emission of specific organic HAP from raw material dryers, and kilns at Portland cement manufacturing facilities, solely for use in applicability determinations under § 63.1340 of this subpart are permitted to use Method 320 of appendix A to this part, or Method 18 of appendix A to part 60 of this chapter.

■ 21. Section 63.1353 is amended by adding paragraph (b)(6) to read as follows:

§ 63.1353 Notification Requirements.

* * * * *

(b) * * *

(6) Within 48 hours of an exceedance that triggers retesting to establish compliance and new operating limits, notify the appropriate permitting agency of the planned performance tests. The notification requirements of §§ 63.7(b) and 63.9(e) do not apply to retesting required for exceedances under this subpart.

■ 22. Section 63.1354 is amended by:

■ a. Removing and reserving paragraphs (b)(4) and (5);

■ b. Revising paragraph (b)(9)(vi);

■ c. Adding paragraph (b)(9)(vii); and

■ d. Revising paragraph (c).

The revisions read as follows:

§ 63.1354 Reporting requirements.

* * * * *

(b) * * *

(9) * * *

(vi) For each PM, HCl, Hg, and THC CEMS or Hg sorbent trap monitoring system, within 60 days after the reporting periods, you must submit reports to the EPA's WebFIRE database by using the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through the EPA's Central Data Exchange (CDX) (*www.epa.gov/cdx*). You must use the appropriate electronic reporting form in CEDRI or provide an alternate electronic file consistent with the EPA's reporting form output format. For each reporting period, the reports must include all of the calculated 30-operating day rolling average values derived from the CEMS or Hg sorbent trap monitoring systems.

(vii) In response to each violation of an emissions standard or established operating parameter limit, the date, duration and description of each violation and the specific actions taken for each violation including inspections, corrective actions and repeat performance tests and the results of those actions.

* * * * *

(c) Reporting a failure to meet a standard due to a malfunction. For each failure to meet a standard or emissions limit caused by a malfunction at an affected source, you must report the failure in the semi-annual compliance report required by § 63.1354(b)(9). The report must contain the date, time and duration, and the cause of each event (including unknown cause, if applicable), and a sum of the number of events in the reporting period. The report must list for each event the affected source or equipment, an estimate of the volume of each regulated pollutant emitted over the emission limit for which the source failed to meet a standard, and a description of the method used to estimate the emissions. The report must also include a description of actions taken by an owner or operator during a malfunction of an affected source to minimize emissions in accordance with § 63.1348(d), including actions taken to correct a malfunction.

■ 23. Section 63.1355 is amended by revising paragraphs (f) and (g)(1) and adding paragraph (h) to read as follows:

§ 63.1355 Recordkeeping Requirements.

* * * * *

(f) You must keep records of the date, time and duration of each startup or shutdown period for any affected source that is subject to a standard during startup or shutdown that differs from the standard applicable at other times, and the quantity of feed and fuel used during the startup or shutdown period.

(g)(1) You must keep records of the date, time and duration of each malfunction that causes an affected source to fail to meet an applicable standard; if there was also a monitoring malfunction, the date, time and duration of the monitoring malfunction; the record must list the affected source or equipment, an estimate of the volume of each regulated pollutant emitted over the standard for which the source failed to meet a standard, and a description of

the method used to estimate the emissions.

* * * * *

(h) For each exceedance from an emissions standard or established operating parameter limit, you must keep records of the date, duration and description of each exceedance and the specific actions taken for each exceedance including inspections, corrective actions and repeat performance tests and the results of those actions.

■ 24. Section 63.1356 is revised to read as follows:

§ 63.1356 Sources with multiple emissions limit or monitoring requirements.

If an affected facility subject to this subpart has a different emissions limit or requirement for the same pollutant under another regulation in title 40 of this chapter, the owner or operator of the affected facility must comply with the most stringent emissions limit or requirement and is exempt from the less stringent requirement.

■ 25. Section 63.1357 is amended by revising paragraphs (a)(1) and (2) to read as follows:

§ 63.1357 Temporary, conditioned exemption from particulate matter and opacity standards.

(a) * * *

(1) Any PM and opacity standards of part 60 or part 63 of this chapter that are applicable to cement kilns and clinker coolers.

(2) Any permit or other emissions or operating parameter or other limitation on workplace practices that are applicable to cement kilns and clinker coolers to ensure compliance with any PM and opacity standards of this part or part 60 of this chapter.

* * * * *

■ 26. Table 3 to Subpart LLL of Part 63 is revised by revising the entries for 63.6(e)(3), 63.7(b), and 63.9(e) to read as follows:

TABLE 3—TO SUBPART LLL OF PART 63—APPLICABILITY OF GENERAL PROVISIONS

Citation	Requirement	Applies to Subpart LLL	Explanation
*	*	*	*
63.6(e)(3)	Startup, Shutdown Malfunction Plan	No	Your operations and maintenance plan must address periods of startup and shutdown. See § 63.1347(a)(1).
*	*	*	*
63.7(b)	Notification period	Yes	Except for repeat performance test caused by an exceedance. See § 63.1353(b)(6)
*	*	*	*
63.9(e)	Notification of performance test	Yes	Except for repeat performance test caused by an exceedance. See § 63.1353(b)(6)
*	*	*	*

[FR Doc. 2012–31633 Filed 2–11–13; 8:45 am]

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minimize litigation, eliminate ambiguity, and reduce burden.

10. Protection of Children

We have analyzed this rule under Executive Order 13045, Protection of Children from Environmental Health Risks and Safety Risks. This rule is not an economically significant rule and does not create an environmental risk to health or risk to safety that may disproportionately affect children.

11. Indian Tribal Governments

This rule does not have tribal implications under Executive Order 13175, Consultation and Coordination with Indian Tribal Governments, because it does not have a substantial direct effect on one or more Indian tribes, on the relationship between the Federal Government and Indian tribes, or on the distribution of power and responsibilities between the Federal Government and Indian tribes.

12. Energy Effects

This action is not a ''significant energy action'' under Executive Order 13211, Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use.

13. Technical Standards

This rule does not use technical standards. Therefore, we did not consider the use of voluntary consensus standards.

14. Environment

We have analyzed this rule under Department of Homeland Security Management Directive 023–01 and Commandant Instruction M16475.lD, which guide the Coast Guard in complying with the National Environmental Policy Act of 1969 (NEPA)(42 U.S.C. 4321–4370f), and have determined that this action is one of a category of actions that do not individually or cumulatively have a significant effect on the human environment. This rule involves establishing a safety zone for a fireworks display launch site and fallout area and is expected to have no impact on the water or environment. This zone is designed to protect mariners and spectators from the hazards associated with aerial fireworks displays. This rule is categorically excluded from further review under paragraph 34 (g) of Figure 2–1 of the Commandant Instruction. An environmental analysis checklist supporting this determination and a Categorical Exclusion Determination are available in the docket where indicated under **ADDRESSES**. We seek any comments or information that may lead to the discovery of a significant environmental impact from this rule.

List of Subjects in 33 CFR Part 165

Harbors, Marine safety, Navigation (water), Reporting and recordkeeping requirements, Security measures, and Waterways.

For the reasons discussed in the preamble, the Coast Guard amends 33 CFR part 165 as follows:

PART 165—REGULATED NAVIGATION AREAS AND LIMITED ACCESS AREAS

■ 1. The authority citation for part 165 continues to read as follows:

Authority: 33 U.S.C. 1231; 46 U.S.C. Chapter 701, 3306, 3703; 50 U.S.C. 191, 195; 33 CFR 1.05–1, 6.04–1, 6.04–6, 160.5; Pub. L. 107–295, 116 Stat. 2064; Department of Homeland Security Delegation No. 0170.1.

■ 2. Add temporary § 165.T05–0259 to read as follows:

§ 165.T05–0259 Safety Zone; Pasquotank River; Elizabeth City, NC.

(a) *Definitions.* For the purposes of this section, Captain of the Port means the Commander, Sector North Carolina.

Representative means any Coast Guard commissioned, warrant, or petty officer who has been authorized to act on the behalf of the Captain of the Port.

(b) *Location.* The following area is a safety zone: Specified waters of the Captain of the Port, Sector North Carolina, as defined in 33 CFR 3.25–20, all waters of the Pasquotank River within a 300 yard radius of the fireworks launch barge in approximate position latitude 36°17′47″ N longitude 076°12′17″, located near Machelhe Island.

(c) *Regulations.* (1) The general regulations contained in § 165.23 of this part apply to the area described in paragraph (b) of this section.

(2) Persons or vessels requiring entry into or passage through any portion of the safety zone must first request authorization from the Captain of the Port, or a designated representative, unless the Captain of the Port previously announced via Marine Safety Radio Broadcast on VHF Marine Band Radio channel 22 (157.1 MHz) that this regulation will not be enforced in that portion of the safety zone. The Captain of the Port can be contacted at telephone number (910) 343–3882 or by radio on VHF Marine Band Radio, channels 13 and 16.

(d) *Enforcement.* The U.S. Coast Guard may be assisted in the patrol and enforcement of the zone by Federal, State, and local agencies.

(e) *Enforcement period.* This section will be enforced on May 18, 2013 from 8 p.m. to 11 p.m. unless cancelled earlier by the Captain of the Port.

Dated: April 12, 2013.

A. Popiel,

Captain, U.S. Coast Guard, Captain of the Sector North Carolina.

[FR Doc. 2013–09609 Filed 4–23–13; 8:45 am]

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ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 60 and 63

[EPA–HQ–OAR–2009–0234; EPA–HQ–OAR–2011–0044; FRL–9789–5]

RIN 2060–AR62

Reconsideration of Certain New Source Issues: National Emission Standards for Hazardous Air Pollutants From Coal- and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule; notice of final action on reconsideration.

SUMMARY: The EPA is taking final action on its reconsideration of certain issues in the final rules titled, ''National Emission Standards for Hazardous Air Pollutants from Coal- and Oil-fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units.'' The National Emission Standards for Hazardous Air Pollutants (NESHAP) rule issued pursuant to Clean Air Act (CAA) section 112 is referred to as the Mercury and Air Toxics Standards (MATS) NESHAP, and the New Source Performance Standards rule issued pursuant to CAA section 111 is referred to as the Utility NSPS. The Administrator received petitions for reconsideration of certain aspects of the MATS NESHAP and the Utility NSPS.

On November 30, 2012, the EPA granted reconsideration of, proposed, and requested comment on a limited set of issues. We also proposed certain technical corrections to both the MATS NESHAP and the Utility NSPS. The EPA is now taking final action on the revised new source numerical standards in the MATS NESHAP and the definitional and monitoring provisions in the Utility NSPS that were addressed in the

proposed reconsideration rule. As part of this action, the EPA is also making certain technical corrections to both the MATS NESHAP and the Utility NSPS. The EPA is not taking final action on requirements applicable during periods of startup and shutdown in the MATS NESHAP or on startup and shutdown provisions related to the PM standard in the Utility NSPS.

DATES: The effective date of the rule is April 24, 2013.

Docket. The EPA established two dockets for this action: Docket ID EPA–HQ–OAR–2011–0044 (NSPS action) and Docket ID EPA–HQ–OAR–2009–0234 (MATS NESHAP action). All documents in the dockets are listed in the *http://www.regulations.gov* index. Although listed in the index, some information is not publicly available (e.g., confidential business information (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 form. Publicly available docket materials are available either electronically in *http://www.regulations.gov* or in hard copy at the EPA Docket Center, Room 3334, 1301 Constitution Avenue 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 Air Docket is (202) 566–1742.

FOR FURTHER INFORMATION CONTACT: For the MATS NESHAP action: Mr. William Maxwell, Energy Strategies Group, Sector Policies and Programs Division, (D243–01), Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711; Telephone number: (919) 541–5430; Fax number (919) 541–5450; Email address: *maxwell.bill@epa.gov.* For the NSPS action: Mr. Christian Fellner, Energy Strategies Group, Sector Policies and Programs Division, (D243–01), Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711; Telephone number: (919) 541–4003; Fax number (919) 541–5450; Email address: *fellner.christian@epa.gov.*

SUPPLEMENTARY INFORMATION:

Outline. The information presented in this preamble is organized as follows:

I. General Information
A. Does this action apply to me?
B. How do I obtain a copy of this document?
C. Judicial Review
II. Background
III. Summary of Today's Action
IV. Summary of Final Action and Changes Since Proposal—MATS NESHAP New Source Issues
V. Summary of Final Action and Changes Since Proposal—Utility NSPS
VI. Technical Corrections and Clarifications
VII. Impacts of This Final Rule
A. Summary of Emissions Impacts, Costs and Benefits
B. What are the air impacts?
C. What are the energy impacts?
D. What are the compliance costs?
E. What are the economic and employment impacts?
F. What are the benefits of the final standards?
VIII. Statutory and Executive Order Reviews
A. Executive Order 12866: Regulatory Planning and Review and Executive Order 13563: Improving Regulation and Regulatory Review
B. Paperwork Reduction Act
C. Regulatory Flexibility Act
D. Unfunded Mandates Reform Act
E. Executive Order 13132: Federalism
F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments
G. Executive Order 13045: Protection of Children From Environmental Health Risks and Safety Risks
H. Executive Order 13211: Actions That Significantly Affect Energy Supply, Distribution, or Use
I. National Technology Transfer and Advancement Act
J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations
K. Congressional Review Act

I. General Information

A. Does this action apply to me?

Categories and entities potentially affected by today's action include:

Category	NAICS code[1]	Examples of potentially regulated entities
Industry	221112	Fossil fuel-fired electric utility steam generating units.
Federal government	[2] 221122	Fossil fuel-fired electric utility steam generating units owned by the Federal government.
State/local/Tribal government	[2] 221122	Fossil fuel-fired electric utility steam generating units owned by municipalities.
	921150	Fossil fuel-fired electric utility steam generating units in Indian country.

[1] North American Industry Classification System.
[2] Federal, State, or local government-owned and operated establishments are classified according to the activity in which they are engaged.

This table is not intended to be exhaustive but rather to provide a guide for readers regarding entities likely to be affected by this action. To determine whether your facility, company, business, organization, etc. would be regulated by this action, you should examine the applicability criteria in 40 CFR 60.40, 60.40Da, or 60.40c or in 40 CFR 63.9982. If you have any questions regarding the applicability of this action to a particular entity, consult either the air permitting authority for the entity or your EPA regional representative as listed in 40 CFR 60.4 or 40 CFR 63.13 (General Provisions).

B. How do I obtain a copy of this document?

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

C. Judicial Review

Under the CAA section 307(b)(1), judicial review of this final rule is available only by filing a petition for review in the U.S. Court of Appeals for the District of Columbia Circuit by June 24, 2013. Under CAA section 307(d)(7)(B), only an objection to this final rule that was raised with reasonable specificity during the period for public comment can be raised during judicial review. Note, under CAA section 307(b)(2), the requirements established by this final rule may not be challenged separately in any civil or criminal proceedings brought by the EPA to enforce these requirements.

II. Background

The final MATS NESHAP and the Utility NSPS rules were published in the **Federal Register** at 77 FR 9304 on

February 16, 2012. Following promulgation of the final rules, the Administrator received petitions for reconsideration of numerous provisions of both the MATS NESHAP and the Utility NSPS pursuant to CAA section 307(d)(7)(B). Copies of the MATS NESHAP petitions are provided in rulemaking docket EPA–HQ–OAR–2009–0234. Copies of the Utility NSPS petitions are provided in rulemaking docket EPA–HQ–OAR–2011–0044. On November 30, 2012, the proposal granting reconsideration of certain issues in the MATS NESHAP and Utility NSPS was published in the **Federal Register** at 77 FR 71323.

III. Summary of Today's Action

This final action amends certain provisions of the final rule issued by the EPA on February 16, 2012. Through an August 2, 2012, notice (77 FR 45967), the EPA delayed the effective date of the February 2012 MATS rule for new sources only. That stay was limited to 90 days and has since expired. The February 2012 final rule is and remains in effect for all sources.

The November 30, 2012, proposed reconsideration rule proposed: (1) Certain revised new source numerical standards in the MATS NESHAP, (2) requirements applicable during periods of startup and shutdown in the MATS NESHAP, (3) startup and shutdown provisions related to the particulate matter (PM) standard in the Utility NSPS, and (4) definitional and monitoring provisions in the Utility NSPS. We also proposed certain technical corrections to both the MATS NESHAP and the Utility NSPS. We are taking final action today on the revised numerical new source MATS NESHAP limits, the definitional and monitoring issues in the Utility NSPS, and all of the technical corrections not related to startup/shutdown issues.

This summary of the final rule reflects the changes to 40 CFR Part 63, subpart UUUUU, and 40 CFR Part 60, subpart Da (77 FR 9304; February 16, 2012) made in this regard.

As noted above, in the proposed reconsideration rule, the EPA took comment on the requirements in the MATS NESHAP applicable during startup and shutdown, including the definitions of startup and shutdown. The EPA also took comment on the startup and shutdown provisions relating to the PM standard in the Utility NSPS. The EPA received considerable comments regarding these startup and shutdown provisions, including data and information relevant to the proposed work practice standard that applies in such periods. The EPA is not taking final action on the startup and shutdown provisions at this time as it needs additional time to consider and evaluate the comments and data provided.[1] The Agency is currently reviewing all of the comments received on the startup and shutdown issues and intends to act promptly to address these issues. We note that no existing sources will have to comply with the existing source MATS standards before April 16, 2015. Further, no new sources are currently under construction and it takes years to complete construction. 77 FR 71330, fn. 7. As such, there will be sufficient time for the Agency to review the comments submitted concerning the proposed startup and shutdown provisions and take appropriate action well in advance of any new source being subject to those provisions.

As described below, on the basis of information provided since the reconsideration proposal, today's action revises certain new source numerical limits in the MATS NESHAP. Specifically, the EPA is finalizing revised hydrogen chloride (HCl), filterable PM (fPM),[2] sulfur dioxide (SO_2), lead (Pb), and selenium emission limits for all new coal-fired EGUs; the mercury (Hg) emission limit for the "unit designed for coal ≥ 8,300 Btu/lb subcategory;" fPM and SO_2 emission limits for new solid oil-derived fuel-fired EGUs; fPM emission limits for new continental liquid oil-fired EGUs; and most of the emission limits for new integrated gasification combined cycle (IGCC) units.

The fPM, HCl, and Hg limits that we are finalizing in this action are provided in table 1; the alternate limits that we are finalizing are provided in table 2.[3]

TABLE 1—REVISED EMISSION LIMITATIONS FOR NEW EGUS

Subcategory	Filterable particulate matter, lb/MWh	Hydrogen chloride, lb/MWh	Mercury, lb/GWh
New—Unit not designed for low rank virgin coal	9.0E–2	1.0E–2 [a]	3.0E–3.
New—Unit designed for low rank virgin coal	9.0E–2	1.0E–2 [a]	NR.
New—IGCC	7.0E–2 [b] 9.0E–2 [c]	2.0E–3	3.0E–3.
New—Solid oil-derived	3.0E–2	NR	NR.
New—Liquid oil—continental	3.0E–1	NR	NR.

Note: lb/MWh = pounds pollutant per megawatt-hour electric output (gross).
lb/GWh = pounds pollutant per gigawatt-hour electric output (gross).
NR = limit not opened for reconsideration (77 FR 9304; February 16, 2012).
[a] Beyond-the-floor value.
[b] Duct burners on syngas; based on permit levels in comments received.
[c] Duct burners on natural gas; based on permit levels in comments received.

TABLE 2—REVISED ALTERNATE EMISSION LIMITATIONS FOR NEW EGUS

Subcategory/pollutant	Coal-fired EGUs	IGCC [a]	Solid oil-derived
SO_2	1.0 lb/MWh	4.0E–1 lb/MWh [b]	1.0 lb/MWh
Total non-mercury metals	NR	4.0E–1 lb/GWh	NR
Antimony, Sb	NR	2.0E–2 lb/GWh	NR
Arsenic, As	NR	2.0E–2 lb/GWh	NR

[1] The EPA is also still reviewing the other issues raised in the petitions for reconsideration and is not taking any action at this time with respect to those issues.

[2] As the final MATS rule established a filterable PM (fPM) limit, every reference in this preamble to a PM limit means filterable PM.

[3] The final rule included certain alternative limits (see 77 FR 9367–9369).

TABLE 2—REVISED ALTERNATE EMISSION LIMITATIONS FOR NEW EGUS—Continued

Subcategory/pollutant	Coal-fired EGUs	IGCC [a]	Solid oil-derived
Beryllium, Be	NR	1.0E–3 lb/GWh	NR
Cadmium, Cd	NR	2.0E–3 lb/GWh	NR
Chromium, Cr	NR	4.0E–2 lb/GWh	NR
Cobalt, Co	NR	4.0E–3 lb/GWh	NR
Lead, Pb	2.0E–2 lb/GWh	9.0E–3 lb/GWh	NR
Mercury, Hg	NA	NA	NR
Manganese, Mn	NR	2.0E–2 lb/GWh	NR
Nickel, Ni	NR	7.0E–2 lb/GWh	NR
Selenium, Se	5.0E–2 lb/GWh	3.0E–1 lb/GWh	NR

NA = not applicable.
NR = limit not opened for reconsideration (77 FR 9304; February 16, 2012).
[a] Based on best-performing similar source.
[b] Based on DOE information.

In addition, in the MATS NESHAP the EPA is removing quarterly stack testing as an option to demonstrate compliance with the new source fPM emission limits; revising the way in which an owner or operator of a new EGU who chooses to use PM continuous parameter monitoring systems (CPMS) establishes an operating limit; requiring inspections and retesting within 45 days of an exceedance of the operating limit for those new EGU owners or operators who choose to use PM CPMS as a compliance option; and finalizing the presumption of violation of the emissions limit if more than 4 emissions tests are required in a 12-month period.

The final changes to the numerical emissions limits noted above incorporate information about the variability of the best performing EGUs and more accurately reflect the capabilities of emission control equipment for new EGUs. The final changes should also address commenters' concerns that vendors of EGU emission controls had been unwilling to provide guarantees regarding the ability to meet all of the standards for new EGUs as originally finalized in February 2012.

We expect that source owners and operators will install and operate the same or similar control technologies to meet the revised standards in this reconsideration action as they would have chosen to comply with the standards in the February 2012 final rule. Consistent with CAA section 112(a)(4), we are maintaining the new source trigger date for the MATS NESHAP rule as May 3, 2011. See 77 FR 71330, fn. 7. New sources must comply with the revised MATS emission standards described in section IV below by April 24, 2013, or startup, whichever is later.

In the February 2012 final Utility NSPS rule, the EPA adopted a definition of natural gas that excludes coal-derived synthetic natural gas consistent with the definition in MATS. In the Utility NSPS reconsideration proposal, we re-proposed and requested comment on that definition. Based on review of the comments received in response to the reconsideration proposal, the EPA has concluded that the definition of natural gas in the final Utility NSPS is appropriate and, therefore, is not making any changes to that definition. We are also finalizing as proposed one conforming amendment and two amendments related to EGUs burning desulfurized coal-derived synthetic natural gas. First, we amended the definition of coal to make it clear that coal-derived synthetic natural gas is considered to be coal. In addition, in recognition of the fact that emissions from the burning of desulfurized coal-derived synthetic natural gas are very similar to those from the burning of natural gas, we amended the opacity and SO_2 monitoring provisions so that facilities burning desulfurized coal-derived synthetic natural gas will have opacity and SO_2 monitoring requirements similar to those of facilities burning natural gas. Further, we are finalizing certain revisions to the definition of IGCC in the Utility NSPS. We are also finalizing as proposed the revised procedures for calculating PM emission rates intended to make the Utility NSPS procedures consistent with those in the MATS NESHAP. We did not receive any adverse comments regarding this proposed change. Finally, we are finalizing as proposed the technical corrections to the PM standards for facilities that commenced construction before March 1, 2005, and for facilities that commence modification after May 3, 2011.

The impacts of today's revisions on the costs and the benefits of the final rule are minor. As noted above, we expect that source owners and operators will install and operate the same or similar control technologies to meet the revised standards in this action as they would have chosen to comply with the standards in the February 2012 final rule.

IV. Summary of Final Action and Changes Since Proposal—MATS NESHAP New Source Issues

After consideration of the public comments received, the EPA has made certain changes in this final action from the reconsideration proposal. We address the most significant comments in this preamble. However for a complete summary of the comments received on the issues we are finalizing today and our responses thereto, please refer to the memorandum "National Emission Standards For Hazardous Air Pollutants From Coal- And Oil-Fired Electric Utility Steam Generating Units—Reconsideration; Summary Of Public Comments And Responses" (March 2013) in rulemaking docket EPA–HQ–OAR–2009–0234.

In this action, we are finalizing certain new source emission limits for the MATS NESHAP, as discussed below.

1. Changes to Certain New Source MATS NESHAP Limits

Commenters noted that in two instances, Pb emissions from coal-fired EGUs and the fPM emissions from continental liquid oil-fired EGUs, the EPA had proposed new source emission limits that were less stringent than those in the final MATS NESHAP for the respective existing sources. This approach was inconsistent with that taken in the final MATS NESHAP.[4] Although CAA section 112(d)(3) allows existing source MACT floor limits to be less stringent than new source limits, the EPA interprets this provision as

[4] See "*National Emission Standards for Hazardous Air Pollutants (NESHAP) Maximum Achievable Control Technology (MACT) Floor Analysis for Coal- and Oil-fired Electric Utility Steam Generating Units for Final Rule,*" Docket ID EPA–HQ–OAR–2009–0234–20132, p. 13.

precluding new source limits from being less stringent than existing source limits. See CAA section 112(d)(3). Thus, for Pb emissions from coal-fired EGUs and fPM emissions from continental liquid oil-fired EGUs, the EPA is finalizing new source limits that are equivalent to the final existing-source limits.

Next, commenters noted that when evaluating SO_2 emissions data from coal-fired EGUs, the EPA had not selected the lowest emitting source upon which to base the emission limit and that its rationale for excluding certain data was unlawful and arbitrary. Although the EPA disagrees with commenters on several of the excluded data sets (i.e., some of the data sets suggested by commenters comprised only a single 3-run average for each EGU with no individual run data, making assessment of variability impossible), it agrees that it inadvertently omitted the data from Stanton Unit 10 in the proposal analyses. Stanton Unit 10 does have a lower ''lowest'' 3-run data average than does the EGU selected for the new source floor analysis (Sandow Unit 5A) in the proposed reconsideration rule.

In this final action, the EPA used the Stanton data to calculate the MACT floor using the same statistical analyses used in the proposed rule (i.e., 99 percent upper predictive limit (UPL)), and the resulting MACT floor emission limit is 1.3 pounds per megawatt-hour (lb/MWh). Because this limit is less stringent than the new source performance standard (NSPS) finalized in the Utility NSPS (77 FR 9451; February 16, 2012), the EPA is finalizing a beyond-the-floor (BTF) MACT standard of 1.0 lb/MWh, which is the same level required by the CAA section 111 NSPS for these same sources.[5] See 40 CFR 60.43Da(l)(1)(i). Cost is a required consideration in establishing CAA section 111 rules and in going BTF in establishing CAA section 112 rules. We evaluated cost in assessing whether to go BTF for this standard and concluded that it was appropriate to go BTF to a level of 1.0 lb/MWh. Moreover, the NSPS limit (also 1.0 lb/MWh) is in place and coal-fired EGUs are required to comply with that limit. As such, there is no additional cost to these sources.[6] Furthermore, we have not identified any non-air quality health or environmental impacts or energy requirements associated with the final standard set at this level. In addition, in support of the proposed reconsideration rule, we evaluated an emissions level more stringent than 1.0 lb/MWh and found that level to not be cost effective.[7] For these reasons, we are finalizing 1.0 lb/MWh as the new source MATS NESHAP limit.

In the proposed reconsideration rule, we indicated that detection level issues may arise from using a sorbent trap when short sampling periods (e.g., 30 minutes) are used. As such, the EPA solicited comment on its establishment of a Representative Detection Level (RDL) associated with Hg sorbent traps. The EPA also solicited comment on whether the UPL calculated floor should be compared against the 3XRDL value for Hg to account for the shorter sampling periods (the 3XRDL approach). The EPA received several comments, ranging from strong support for the Hg RDL and the proposed emission limit because, at that level, the commenters asserted that vendors would be able to provide commercial guarantees, to concerns about the specific inputs to the 3XRDL calculation and the application of the 3xRDL approach. See section 2.2.1 of the response to comments document (RTC) for a more complete discussion and response to these comments.

In the proposed reconsideration rule, the EPA recognized that 30 minutes of sample collection is the shortest reasonable amount of time available for collecting and changing sorbent tubes to provide the quick, reliable feedback that will allow sources to react to changing Hg emissions levels and assure compliance with the final Hg limit. Some commenters pointed out that the EPA's memorandum entitled ''Determination of Representative Detection Level (RDL) and 3 X RDL Values for Mercury Measured Using Sorbent Trap Technologies,''[8] contains a 30-minute sample collection time in the 3XRDL calculation, but the text of the memorandum references a 20-minute sample collection time. The EPA has revised the text of the memorandum to reflect its original intent, which was to focus on a sample collection period of 30 minutes (not 20 minutes). The revised memorandum focuses on the 30-minute sample collection period. Given that it takes 5 minutes for sorbent trap insertion and removal, it would take a total of 40 minutes to secure the requisite sample collection (30 minutes for sample collection, 5 minutes to remove the sorbent trap, and 5 minutes to re-insert the trap). We are finalizing the Hg limit using the 3XRDL approach assuming a 30-minute sampling time.

2. Filterable PM Testing, Monitoring, and Compliance

Certification for New EGUs in the MATS NESHAP Rule

Several monitoring options for the fPM standard for new sources were provided in the MATS NESHAP final rule, including quarterly stack testing, PM CEMS, and PM CPMS with annual testing.

The EPA sought comment on whether to retain the quarterly stack testing compliance option for new EGUs, given that continuous, direct measurement of fPM or a correlated parameter is available, is preferable for determining compliance on a continuous basis, and is likely to be used by most new EGUs to monitor compliance with the proposed new source standards. As mentioned above, this final action does not retain the quarterly fPM performance testing option for new EGUs. New EGUs can be designed to incorporate PM CEMS or PM CPMS from the outset, without being impeded by retrofit location installation constraints that could impact existing EGUs. This final action now requires new sources to use either PM CEMS or PM CPMS as options for determining compliance with the new source fPM limits.

The EPA requested comment on a number of issues associated with PM CPMS. The EPA first solicited comment on three approaches to establish an operating limit based on emissions testing for those EGU owners or operators who choose to use PM CPMS as the means of demonstrating compliance with the fPM emission limit. The first approach would require an EGU owner or operator to use the highest parameter value obtained during any run of an individual emissions test as the operating limit when the result of that individual test was below the limit. The second approach would require an EGU owner or operator to use the average parameter value obtained from

[5] The CAA section 111 standard is based on the performance of EGUs with the best performing SO_2 controls, a reasonable incremental cost effectiveness of less than $1,000 per ton of SO_2 controlled, and controls that result in minimal secondary environmental and energy impacts.

[6] The final Utility NSPS limit was not challenged and coal-fired EGUs constructed after May 3, 2011, must meet that limit.

[7] See Docket ID EPA–HQ–OAR–2009–0234–20221 and *National Emission Standards for Hazardous Air Pollutants (NESHAP) Beyond the Maximum Achievable Control Technology (MACT) Floor ('Beyond-the-Floor') Analysis for Revised Emission Standards for New Source Coal-and Oil-fired Electric Utility Steam Generating Units* also in the rulemaking docket.

[8] The EPA developed the memorandum to determine appropriate RDL and 3XRDL values for sorbent trap monitoring systems, as well as calculate an emissions limit, in order to determine the shortest, reasonable sample collection period for those systems. See EPA Docket ID EPA–HQ–OAR–2009–0234–20222.

all runs of an individual emissions test as the operating limit, provided that the result of the individual emissions test met the emissions limit. The third approach, which the EPA is finalizing in this final action, would require an EGU owner or operator to use the higher of the following: (1) A parameter scaled from all values obtained during an individual emissions test to 75 percent of the emissions limit or (2) the average parameter value obtained from all runs of an individual emissions test as the operating limit provided that the result of the individual emissions test met the emissions limit. As established and reaffirmed in the recent Sewage Sludge Incineration, Major Source Industrial Boiler, and Portland Cement rules,[9] it is appropriate to provide increased operational flexibility and reduced emissions testing for sources that emit at or below 75 percent of a standard—whether an emissions or operating limit—as these are the lowest emitting sources. Reduced emissions testing is available in this final rule for those owners or operators whose EGU emissions do not exceed this 75 percent threshold. This 75 percent threshold allows for compliance flexibility and is simultaneously protective of the emission standards. The EPA believes well performing EGUs, i.e., those whose emissions do not exceed 75 percent of the emissions limit, should not face additional scrutiny or testing consequences provided their emissions remain equivalent to or below the 75 percent threshold. In this final action, the EPA uses the 75 percent threshold so as not to impose unintended and costly retest requirements for the lowest emitting sources and to provide for more cost effective, continuous, PM parametric monitoring across the EGU sector. This approach was selected from the options considered as it provides the greatest amount of EGU owner or operator flexibility while demonstrating continuous compliance for EGUs. With this parametric monitoring approach in place, the EPA expects EGUs to evaluate control options that provide excellent fPM emissions control and provide them greater operational flexibility.

Moreover, after each exceedance of the operating limit, the EPA proposed to require emissions testing to verify or re-adjust the operating limit, consistent with the approach contained in the recently-promulgated Portland cement MACT standard (see 78 FR 10014). One commenter objected to potential frequent emissions testing to reassess the operating limit and then being subject to a violation of the emissions limit. The EPA does not believe that too-frequent testing will be required. As discussed in section 4.3.5 of the RTC, the EPA believes well-designed emissions testing will provide an operating limit corresponding with EGU operation, and such testing should yield an operating limit that would not be expected to be exceeded during the course of EGU operation. Therefore, an operating limit developed from well-designed emissions testing should have little, if any, need for frequent reassessment via emissions testing more frequently than the mandated annual reassessment because the source will be able to meet the limit on an ongoing basis.

Finally, the EPA proposed that PM CPMS exceedances leading to more than 4 required emissions tests in a 12-month period (rolling monthly) would be presumed (subject to the possibility of rebuttal by the EGU owner or operator) to be a violation of the emissions limit, consistent with the approach contained in the newly-promulgated Portland cement MACT standard (see 78 FR 10014). The EPA received a number of comments on this proposed provision, including comments supporting and opposing the establishment of such a presumption.

The EPA disagrees with those comments opposing the presumptive violation, and believes the presumptive violation provision in the final rule is a reasonable and appropriate approach to ensure compliance with the standard. First, the EPA may permissibly establish such an approach by rule, assuming there is a reasonable factual basis to do so. See *Hazardous Waste Treatment Council* v. *EPA,* 886 F. 2d 355, 367–68 (DC Cir. 1989) (explaining that such presumptions can legitimately establish the elements of the EPA's *prima facie* case in an enforcement action). Second, there is a reasonable basis here for the presumption that four exceedances (i.e., increases over the parametric operating limit) in a calendar year are a violation of the emission standard. The parametric monitoring limit is established as a 30-day average of the averaged test value in the performance test, or the 75th percentile value if that is higher. In either instance, the 30-day averaging feature provides significant leeway to the EGU owner or operator not to deviate from the parametric operating level because the impact of transient peaks or valleys is limited due to the length of the rule's averaging period—30 boiler operating days, rolled daily. See 77 FR 42377/2 and sources there cited. See also 78 FR 10015, 10019; February, 12, 2013 (Portland Cement MACT) and the RTC for today's action.

The EPA also received comments addressing the re-testing requirements following an exceedance. Some commenters expressed concern about the burden of requiring sources to conduct performance tests in order to demonstrate compliance and to reassess the parameter level. In contrast, other commenters supported a requirement to require re-testing but claimed that the time period between observing a parameter exceedance and retesting is too long. The EPA believes that the re-testing requirements are reasonable and appropriate to identify non-compliance without imposing undue burden. For even a single exceedance to occur, the 30-day average would have to be higher than the operating limit established for the PM CPMS during normal EGU operation. If that occurs, then the EGU owner or operator is required to conduct an inspection to determine any abnormalities and an emissions test to re-establish or generate a new operating limit. Given that EGUs and their emissions control devices are designed to operate at known, specific conditions, deviations from these conditions are not expected and are indicative of problems with load, controls, or some combination of both. Where these sorts of problems result in an exceedance of the source's operating limit, it is reasonable to require re-testing in order to identify and then correct problems. More than four such exceedances of the 30-day average would mean that the EGU owner or operator was unable to determine or correct the problem, since inspection and re-calculation of the operating limit is required after each exceedance. This indicates an ongoing problem with maintaining process control and/or control device operation, which would be the basis for a presumptive violation of the emissions standard. Moreover, the EPA disagrees that the period between exceedance of the operating limit and retesting is too long and could result in possible excessive emissions. Specifically, some commenters claimed that the final rule should not limit the number of exceedances of the PM CPMS limit that require follow-up performance tests in any 12-month period. These commenters alleged that to do so does

[9] See *Standards of Performance for New Stationary Sources and Emission Guidelines for Existing Sources: Commercial and Industrial Solid Waste Incineration Units,* 76 FR 15736 (March 21, 2011); *Subpart DDDDD—National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters,* 40 CFR 63.7515(b); and *National Emission Standards for Hazardous Air Pollutants for the Portland Cement Manufacturing Industry and Standards of Performance for Portland Cement Plants,* 78 FR 10014 (February 12, 2013).

not ensure continuous compliance because the time period between an exceedance and testing could be too long, and a source could be exceeding the emission limit during that time period. The EPA believes that the re-testing requirements reflect a reasonable balance between ensuring compliance and limiting unnecessary testing burden on regulated sources. An EGU owner or operator is required to visually inspect the air pollution control device within 48 hours of the exceedance, and corrective action must be taken as soon as possible to return the PM CPMS measurement to within the established value. A performance test is also required within 45 days of the exceedance to determine compliance and verify or re-establish the PM CPMS limit. Thus, the EPA finds it unlikely that there will be long periods of noncompliance with the underlying fPM standard given the inspection and performance testing requirements.

The EPA also received comments stating that an EGU owner or operator should not be labeled a ''violator'' of the fPM standard as a result of a fourth compliance test in a 12-month period. First, the EPA notes that the rule identifies more than 4 compliance tests over a 12-month period as only a presumptive violation of the emissions limit. A presumption of a violation is just that—a presumption—and can be rebutted in any particular case.

Moreover, in determining whether the presumption has been successfully rebutted, a Court may consider relevant information such as data or other information showing that the EGU's operating process remained in control during the period of operating parameter exceedance, that the ongoing operation and maintenance conducted on the EGU ensured its emissions control devices remained in proper operating condition during the period of operating parameter exceedance, and that results of emissions tests conducted while replicating the conditions observed during the period of operating parameter exceedance remained below the emission limit.

For the reasons explained above, this final action includes the presumption of violation of the emissions limit if more than 4 emissions tests are required in a 12-month period.

V. Summary of Final Action and Changes Since Proposal—Utility NSPS

The EPA has made a number of changes from the reconsideration proposal in this final action after consideration of the public comments received. Most of the changes to the Utility NSPS clarify applicability and implementation issues raised by the commenters. The public comments received on the matters proposed for reconsideration and the responses to them can be viewed in the memorandum ''Summary of EGU NSPS Public Comments and Responses on Amendments Proposed November 30, 2012 (77 FR 71323)'' in rulemaking docket EPA–HQ–OAR–2011–0044.

In the proposed reconsideration rule, the EPA proposed a new definition for IGCC which would be consistent with the MATS NESHAP definition. However, as an alternative we requested comment on whether to retain a definition similar, but not identical, to the IGCC definition in the February 2012 final Utility NSPS. We have concluded that the alternative approach is most appropriate and are adopting a slightly revised definition that is consistent with the Agency's statements on IGCC contained in the RTC in support of the final Utility NSPS rule published on February 16, 2012 (77 FR 9304). Commenters generally supported amending the final Utility NSPS definition of IGCC, and this final action amends that definition consistent with the statements made in the RTC for the Utility NSPS. The Utility NSPS IGCC definition deals with the intent of an IGCC facility and is, thus, broader than the definition in the MATS NESHAP. The facility would still be subject to the same criteria pollutant emission standards even when burning natural gas for extended periods of time. The MATS NESHAP applicability is determined based on the EGU's utilization of coal and oil and the rule may not apply depending on the extent of natural gas usage.

The EPA proposed that the NSPS PM monitoring procedures be consistent with the MATS NESHAP requirements and included the use of quarterly stack testing, PM CPMS, or PM CEMS. In addition, the EPA sought comment on whether to include the quarterly stack testing compliance option for new EGUs, given that continuous, direct measurement of PM or a correlated parameter is available. EGUs complying with an output-based emissions standard can be designed to incorporate PM CEMS or PM CPMS from the outset, without being impeded by retrofit location installation constraints that would impact existing EGUs. This final action requires EGUs complying with an output-based standard to use either PM CEMS or PM CPMS as options for determining compliance with the PM limits. Therefore, the EPA is finalizing the same monitoring procedures for PM for the Utility NSPS as for new sources subject to the MATS NESHAP, and is not finalizing the quarterly stack testing option.

The EPA proposed that facilities using PM CPMS would be able to use either a continuous opacity monitoring system or a periodic alternate monitoring approach to monitor opacity. This final action does not require facilities using a PM CPMS to conduct opacity monitoring. The EPA has concluded that the use of a PM CPMS at the level of the emissions standard required in subpart Da is sufficient to demonstrate compliance with the opacity standard and that additional monitoring is an unnecessary burden.

VI. Technical Corrections and Clarifications

On April 19, 2012 (77 FR 23399), the EPA issued a technical corrections notice addressing certain corrections to the February 16, 2012 (77 FR 9304), MATS NESHAP and Utility NSPS. In the November 30, 2012, reconsideration proposal, we proposed several additional technical corrections. Specific to the NSPS, we proposed correcting the PM standard for facilities that commenced construction before March 1, 2005, to remove the extra significant digit that was inadvertently added and to correct the PM standard for facilities that commence modification after May 3, 2011, to be consistent with the original intent as expressed in the RTC of the final rule published on February 16, 2012 (77 FR 9304). We did not receive any negative comments on these issues and are finalizing them as proposed. Specific details are included in Table 3.

Specific to the MATS NESHAP, the EPA requested comment on whether the proposed technical corrections in Table 4 of the preamble provide the intended accuracy, clarity, and consistency. As mentioned in section 6.3 of the RTC, commenters supported the proposed changes on equations 2a and 3a and this final action contains those changes. As mentioned in section 6.3 of the RTC, commenters did not support the change from a 30 to 60-day notification period for performance testing, and that change was not made to the rule; however, a change to the General Provisions applicability table was made to provide a consistent 30-day notification period. Commenters suggested changes to certain definitions to make them more consistent with the Acid Rain rule provisions, but, as described in section 6.4 of the RTC, these rule changes were not made. These amendments are now being finalized to correct inaccuracies and other inadvertent errors in the final rule and to make the rule language

consistent with provisions addressed through this reconsideration.

The final technical changes are described in tables 3 and 4 of this preamble.

TABLE 3—MISCELLANEOUS TECHNICAL CORRECTIONS TO 40 CFR PART 60, SUBPART DA

Section of subpart Da	Description of correction
40 CFR 60.42Da(a)	Correct the erroneous "0.030" to the correct "0.03".
40 CFR 60.42Da(e)(1)(ii)	Correct the erroneous conversion "13 ng/J (0.015 lb/MMBtu)" to the correct "6.4 ng/J (0.015 lb/MMBtu)" by amending the regulatory text to specify that the requirements in 40 CFR 60.42Da(c) or (d), which includes two additional alternative limits, are available compliance alternatives for modified facilities.

TABLE 4—MISCELLANEOUS TECHNICAL CORRECTIONS TO 40 CFR PART 63, SUBPART UUUUU

Section of subpart UUUUU	Description of correction
40 CFR 63.9982(a)	Clarify the language to use the word "or" instead of "and."
40 CFR 63.9982(b) and (c)	Correct the discrepancy between 63.9982(b) and (c) and 63.9985(a).
40 CFR 63.10005(d)(2)(ii)	Correct the typographical error by replacing the incorrect "corresponding" with the correct "corresponds."
40 CFR 63.10005(i)(4)(ii) and (i)(5) and add 63.10005(i)(6).	Revise to clarify the determination and measurement of fuel moisture content.
40 CFR 63.10006(c)	Correct the omission of solid oil-derived fuel- and coal-fired EGUs and IGCC EGUs and the omission of section 10000(c).
40 CFR 63.10007(c)	Correct the omission of section 63.10023 from the list of sections to be followed in establishing an operating limit.
40 CFR 63.10009(b)(2)	Correct omission of the term "boiler operating" and clarify the term "Rt_i" in Equation 2a.
40 CFR 63.10009(b)(3)	Correct omission of the term "system" and clarify the term "Rt_i" in Equation 3a.
40 CFR 63.10010(j)(1)(i)	Correct the typographical error to use the correct word "your" instead of "you."
40 CFR 63.10030(b), (c), and (d)	Clarify the affected-source language.
	Change the period by which a Notification of Intent to conduct a performance test must be submitted to conform to the General Provisions.
40 CFR Section 63.10042	Correct the typographical error in the intended definition of "unit designed for coal ≥ 8,300 Btu/lb subcategory" by replacing the erroneous ">" with the correct "≥."
Table 5 to Subpart UUUUU of Part 63.	Correct the typographical error in footnote 4 by replacing the erroneous "≥" with the correct "≤."
Table 7 to Subpart UUUUU of Part 63.	Clarify the applicability of the alternate 90-day average for Hg in item 1.
	Revise item 3 in the table to clarify use of CMS for liquid oil-fired EGUs.
Table 9 to Subpart UUUUU of Part 63.	Revise to clarify the period for notification of conducting a performance test from 60 to 30 days.
Section 4.1 to Appendix A to Subpart UUUUU of Part 63.	Correct the typographical error by replacing the incorrect citation to "§ 63.10005(g)" with the correct "§ 63.9984(f)."
Section 5.2.2.2 to Appendix A to Subpart UUUUU of Part 63.	Correct the typographical error by replacing the incorrect citation to "Table A–4" with the correct "Table A–2"
Section 3.1.2.1.3 to Appendix B to Subpart UUUUU of Part 63.	Correct the typographical error by replacing the erroneous "≥" with the correct "≤."
Section 5.3.4 to Appendix B to Subpart UUUUU of Part 63.	Correct the section number from the incorrect "5.3.4" to the correct "5.3.3."

VII. Impacts of This Final Rule

A. Summary of Emissions Impacts, Costs and Benefits

Our analysis shows that new EGUs would choose to install and operate the same or similar air pollution control technologies in order to meet the revised emission limits as would have been necessary to meet the previously finalized standards. We project that this final action will result in no significant change in costs, emission reductions, or benefits.[10] Even if there were changes in costs for these EGUs, such changes would likely be small relative to both the overall costs of the individual projects and the overall costs and benefits of the final rule. Further, we believe that EGUs would put on the same controls for this final action that they would have for the original final MATS rule, so there should not be any incremental costs related to this revision.

B. What are the air impacts?

We believe that electric power companies will install the same or similar control technologies to comply with the final standards in this action as they would have installed to comply with the previously finalized MATS standards. Accordingly, we believe that this final action will not result in significant changes in emissions of any of the regulated pollutants.

C. What are the energy impacts?

This final action is not anticipated to have an effect on the supply, distribution, or use of energy. As previously stated, we believe that electric power companies would install the same or similar control technologies as they would have installed to comply with the previously finalized MATS standards.

D. What are the compliance costs?

We believe there will be no significant change in compliance costs as a result of this final action because electric

[10] See *Regulatory Impact Analysis for the Final Mercury and Air Toxics Standards [EPA–452/R–11–011]* (docket entry EPA–HQ–OAR–2009–0234–20131) and *Economic Impact Analysis for the Final Reconsideration of the Mercury and Air Toxics Standards* in rulemaking docket EPA–HQ–OAR–2009–0234. As noted earlier, because on an individual EGU-by-EGU basis we anticipate very similar costs, any changes to the baseline since we finalized MATS (e.g., potential impacts of the CSAPR decision) would not impact this determination.

power companies would install the same or similar control technologies as they would have installed to comply with the previously finalized MATS standards. Moreover, we find no additional monitoring costs are necessary to comply with this final action; however, as in any other rule, EGU owners or operators may choose to conduct additional monitoring (and incur its expense) for their own purposes.

E. What are the economic and employment impacts?

Because we expect that electric power companies would install the same or similar control technologies to meet the standards finalized in this action as they would have chosen to comply with the previously finalized MATS standards, we do not anticipate that this final action will result in significant changes in emissions, energy impacts, costs, benefits, or economic impacts. Likewise, we believe this action will not have any impacts on the price of electricity, employment or labor markets, or the U.S. economy.

F. What are the benefits of the final standards?

As previously stated, the EPA anticipates the power sector will not incur significant compliance costs or savings as a result of this action and we do not anticipate any significant emission changes resulting from this action. Therefore, there are no direct monetized benefits or disbenefits associated with this action.

VIII. Statutory and Executive Order Reviews

A. Executive Order 12866: Regulatory Planning and Review and Executive Order 13563: Improving Regulation and Regulatory Review

Under Executive Order (EO) 12866 (58 FR 51735; October 4, 1993), this action is a ''significant regulatory action'' because it ''raises novel legal or policy issues.'' Accordingly, the EPA submitted this action to the Office of Management and Budget (OMB) for review under Executive Orders 12866 and 13563 (76 FR 3821; January 21, 2011) and any changes made in response to OMB recommendations have been documented in the docket for this action.

In addition, the EPA prepared an analysis of the potential costs and benefits associated with this action. This analysis is contained in the ''Economic Impact Analysis for the Final Reconsideration of the Mercury and Air Toxics Standards'' found in rulemaking docket EPA–HQ–OAR–2009–0234. Because our analysis shows that new electricity generating units would choose to install the same control technology in order to meet the revised emission limits as would have been necessary to meet the previously finalized MATS standards, we project that this action will result in no significant change in costs, emission reductions, or benefits.

B. Paperwork Reduction Act

This action does not impose any new information collection burden. Today's action does not change the information collection requirements previously finalized and, as a result, does not impose any additional burden on industry. However, OMB has previously approved the information collection requirements contained in the existing regulations (see 77 FR 9304) under the provisions of the Paperwork Reduction Act, 44 U.S.C. 3501 *et seq.* and has assigned OMB control number 2060–0567. The OMB control numbers for EPA's regulations are listed in 40 CFR part 9 and 48 CFR chapter 15.

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 will 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 impacts of today's action on small entities, a small entity is defined as: (1) A small business as defined by the Small Business Administration's (SBA) regulations at 13 CFR 121.201; (2) a small governmental jurisdiction that is a government of a city, county, town, school district, or special district with a population of less that 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. Categories and entities potentially regulated by the final rule with applicable NAICS codes are provided in the Supplementary Information section of this action.

According to the SBA size standards for NAICS code 221122 Utilities-Fossil Fuel Electric Power Generation, a firm is small if, including its affiliates, it is primarily engaged in the generation, transmission, and or distribution of electric energy for sale and its total electric output for the preceding fiscal year did not exceed 4 million MWh.

After considering the economic impacts of today's action on small entities, I certify that the notice will not have a significant economic impact on a substantial number of small entities.

The EPA has determined that none of the small entities will experience a significant impact because the action imposes no additional regulatory requirements on owners or operators of affected sources. We have therefore concluded that today's action will not result in a significant economic impact on a substantial number of small entities.

D. Unfunded Mandates Reform Act

This action 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. The action imposes no enforceable duty on any State, local, or tribal governments or the private sector. Therefore, this action is not subject to the requirements of UMRA sections 202 or 205.

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

E. Executive Order 13132: Federalism

This action 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 EO 13132. None of the affected facilities are owned or operated by state governments, and the requirements discussed in today's notice will not supersede state regulations that are more stringent. Thus, EO 13132 does not apply to today's notice of reconsideration.

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

This action does not have tribal implications. It will not have substantial direct effects on tribal governments, on the relationship between the Federal government and Indian tribes, or on the distribution of power and responsibilities between the Federal government and Indian tribes, as specified in EO 13175. No affected

facilities are owned or operated by Indian tribal governments. Thus, EO 13175 does not apply to today's action.

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

This action is not subject to EO 13045 (62 FR 19885; April 23, 1997) because it is not economically significant as defined in EO 12866. The EPA has evaluated the environmental health or safety effects of the final MATS on children. The results of the evaluation are discussed in that final rule (77 FR 9304; February 16, 2012) and are contained in rulemaking docket EPA–HQ–OAR–2009–0234.

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

This action is not a "significant energy action" as defined in EO 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. Further, we conclude that today's action is not likely to have any adverse energy effects because it is not expected to impose any additional regulatory requirements on the owners of affected facilities.

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 in their regulatory and procurement activities unless to do so would be inconsistent with applicable law or otherwise impracticable. Voluntary consensus standards are technical standards (e.g., material specifications, test methods, sampling procedures, business practices) developed or adopted by one or more voluntary consensus bodies. The NTTAA requires EPA to provide Congress, through the OMB, with explanations when EPA decides not to use available and applicable voluntary consensus standards.

During the development of the final MATS rule, the EPA searched for voluntary consensus standards that might be applicable. The search identified three voluntary consensus standards that were considered practical alternatives to the specified EPA test methods. An assessment of these and other voluntary consensus standards is presented in the preamble to the final MATS rule (77 FR 9441; February 16, 2012). Today's action does not make use of any additional technical standards beyond those cited in the final MATS rule. Therefore, the EPA is not considering the use of any additional voluntary consensus standards for this action.

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.

The EPA has determined that this action 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. Our analysis shows that new EGUs would choose to install the same control technology in order to meet the revised emission limits as would have been necessary to meet the previously finalized standard. Under the relevant assumptions, we project that this action will result in no significant change in emission reductions.

K. Congressional Review Act

The Congressional Review Act, 5 U.S.C. 801 *et seq.,* as added by the Small Business Regulatory Enforcement Fairness Act of 1996, generally provides that before a rule may take effect, the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of the Congress and to the Comptroller General of the United States. The EPA will submit a report containing this final action and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the United States prior to publication of the rule in the **Federal Register**. A major rule cannot take effect until 60 days after it is published in the **Federal Register**. This action is not a "major rule" as defined by 5 U.S.C. 804(2). This rule will be effective April 24, 2013.

List of Subjects in 40 CFR Parts 60 and 63

Environmental protection, Administrative practice and procedure, Air pollution control, Hazardous substances, Intergovernmental relations, Reporting and recordkeeping requirements.

Dated: March 28, 2013.

Bob Perciasepe,

Acting Administrator.

For the reasons discussed in the preamble, 40 CFR parts 60 and 63 are amended to read as follows:

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

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

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

■ 2. Amend § 60.41Da by revising the definitions of "Coal" and "Integrated gasification combined cycle electric utility steam generating unit," and by adding the definition of "Natural gas" in alphabetical order to read as follows:

§ 60.41Da Definitions.

* * * * *

Coal means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by the American Society of Testing and Materials in ASTM D388 (incorporated by reference, see § 60.17) and coal refuse. Synthetic fuels derived from coal for the purpose of creating useful heat, including but not limited to solvent-refined coal, gasified coal, coal-oil mixtures, and coal-water mixtures are included in this definition for the purposes of this subpart.

* * * * *

Integrated gasification combined cycle electric utility steam generating unit or *IGCC electric utility steam generating unit* means an electric utility combined cycle gas turbine that is designed to burn fuels containing 50 percent (by heat input) or more solid-derived fuel not meeting the definition of natural gas. The Administrator may waive the 50 percent solid-derived fuel requirement during periods of the gasification system construction, startup and commissioning, shutdown, or repair. No solid fuel is directly burned in the unit during operation.

* * * * *

Natural gas means a fluid mixture of hydrocarbons (e.g., methane, ethane, or propane), composed of at least 70 percent methane by volume or that has a gross calorific value between 35 and 41 megajoules (MJ) per dry standard cubic meter (950 and 1,100 Btu per dry standard cubic foot), that maintains a gaseous state under ISO conditions. In addition, *natural gas* contains 20.0 grains or less of total sulfur per 100 standard cubic feet. Finally, natural gas

does not include the following gaseous fuels: landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable sulfur content or heating value.

* * * * *

■ 3. Amend § 60.42Da by revising paragraphs (a), (b)(2), and (e)(1) to read as follows:

§ 60.42Da Standards for particulate matter (PM).

(a) Except as provided in paragraph (f) of this section, on and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, an owner or operator of an affected facility shall not cause to be discharged into the atmosphere from any affected facility for which construction, reconstruction, or modification commenced before March 1, 2005, any gases that contain PM in excess of 13 ng/J (0.03 lb/MMBtu) heat input.

(b) * * *

(2) An owner or operator of an affected facility that combusts only natural gas and/or synthetic natural gas that chemically meets the definition of natural gas is exempt from the opacity standard specified in paragraph (b) of this section.

* * * * *

(e) * * *

(1) On and after the date on which the initial performance test is completed or required to be completed under § 60.8, whichever date comes first, the owner or operator shall not cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of the applicable emissions limit specified in paragraphs (e)(1)(i) or (ii) of this section.

(i) For an affected facility which commenced construction or reconstruction:

(A) 11 ng/J (0.090 lb/MWh) gross energy output; or

(B) 12 ng/J (0.097 lb/MWh) net energy output.

* * * * *

(ii) For an affected facility which commenced modification, the emission limits specified in paragraphs (c) or (d) of this section.

* * * * *

■ 4. Amend § 60.48Da by revising paragraphs (f), (o) introductory text, (o)(1), (o)(2) introductory text, (o)(3) introductory text, (o)(3)(i), and (o)(4) introductory text to read as follows:

§ 60.48Da Compliance provisions.

* * * * *

(f) For affected facilities for which construction, modification, or reconstruction commenced before May 4, 2011, compliance with the applicable daily average PM emissions limit is determined by calculating the arithmetic average of all hourly emission rates each boiler operating day, except for data obtained during startup, shutdown, or malfunction periods. Daily averages must be calculated for boiler operating days that have out-of-control periods totaling no more than 6 hours of unit operation during which the standard applies. For affected facilities for which construction or reconstruction commenced after May 3, 2011, that elect to demonstrate compliance using PM CEMS, compliance with the applicable PM emissions limit in § 60.42Da is determined on a 30-boiler operating day rolling average basis by calculating the arithmetic average of all hourly PM emission rates for the 30 successive boiler operating days, except for data obtained during periods of startup or shutdown.

* * * * *

(o) Compliance provisions for sources subject to § 60.42Da(c)(2), (d), or (e)(1)(ii). Except as provided for in paragraph (p) of this section, the owner or operator must demonstrate compliance with each applicable emissions limit according to the requirements in paragraphs (o)(1) through (o)(5) of this section.

(1) You must conduct a performance test to demonstrate initial compliance with the applicable PM emissions limit in § 60.42Da by the applicable date specified in § 60.8(a). Thereafter, you must conduct each subsequent performance test within 12 calendar months following the date the previous performance test was required to be conducted. You must conduct each performance test according to the requirements in § 60.8 using the test methods and procedures in § 60.50Da. The owner or operator of an affected facility that has not operated for 60 consecutive calendar days prior to the date that the subsequent performance test would have been required had the unit been operating is not required to perform the subsequent performance test until 30 calendar days after the next boiler operating day. Requests for additional 30 day extensions shall be granted by the relevant air division or office director of the appropriate Regional Office of the U.S. EPA.

(2) You must monitor the performance of each electrostatic precipitator or fabric filter (baghouse) operated to comply with the applicable PM emissions limit in § 60.42Da using a continuous opacity monitoring system (COMS) according to the requirements in paragraphs (o)(2)(i) through (vi) unless you elect to comply with one of the alternatives provided in paragraphs (o)(3) and (o)(4) of this section, as applicable to your control device.

* * * * *

(3) As an alternative to complying with the requirements of paragraph (o)(2) of this section, an owner or operator may elect to monitor the performance of an electrostatic precipitator (ESP) operated to comply with the applicable PM emissions limit in § 60.42Da using an ESP predictive model developed in accordance with the requirements in paragraphs (o)(3)(i) through (v) of this section.

(i) You must calibrate the ESP predictive model with each PM control device used to comply with the applicable PM emissions limit in § 60.42Da operating under normal conditions. In cases when a wet scrubber is used in combination with an ESP to comply with the PM emissions limit, the wet scrubber must be maintained and operated.

* * * * *

(4) As an alternative to complying with the requirements of paragraph (o)(2) of this section, an owner or operator may elect to monitor the performance of a fabric filter (baghouse) operated to comply with the applicable PM emissions limit in § 60.42Da by using a bag leak detection system according to the requirements in paragraphs (o)(4)(i) through (v) of this section.

* * * * *

■ 5. Amend § 60.49Da by:

■ a. Revising paragraphs (a) introductory text;

■ b. Adding paragraph (a)(3)(iv); and

■ c. Revising paragraphs (a)(4), (b) introductory text, and (t).

The revised and added text reads as follows:

§ 60.49Da Emission monitoring.

(a) An owner or operator of an affected facility subject to the opacity standard in § 60.42Da must monitor the opacity of emissions discharged from the affected facility to the atmosphere according to the applicable requirements in paragraphs (a)(1) through (4) of this section.

* * * * *

(3) * * *

(iv) If the maximum 6-minute opacity is less than 10 percent during the most recent Method 9 of appendix A–4 of this part performance test, the owner or operator may, as an alternative to

performing subsequent Method 9 of appendix A–4 performance tests, elect to perform subsequent monitoring using a digital opacity compliance system according to a site-specific monitoring plan approved by the Administrator. The observations must be similar, but not necessarily identical, to the requirements in paragraph (a)(3)(iii) of this section. For reference purposes in preparing the monitoring plan, see OAQPS ''Determination of Visible Emission Opacity from Stationary Sources Using Computer-Based Photographic Analysis Systems.'' This document is available from the U.S. Environmental Protection Agency (U.S. EPA); Office of Air Quality and Planning Standards; Sector Policies and Programs Division; Measurement Policy Group (D243–02), Research Triangle Park, NC 27711. This document is also available on the Technology Transfer Network (TTN) under Emission Measurement Center Preliminary Methods.

* * * * *

(4) An owner or operator of an affected facility that is subject to an opacity standard under § 60.42Da is not required to operate a COMS provided that affected facility meets the conditions in either paragraph (a)(4)(i) or (ii) of this section.

(i) The affected facility combusts only gaseous and/or liquid fuels (excluding residue oil) where the potential SO_2 emissions rate of each fuel is no greater than 26 ng/J (0.060 lb/MMBtu), and the unit operates according to a written site-specific monitoring plan approved by the permitting authority. This monitoring plan must include procedures and criteria for establishing and monitoring specific parameters for the affected facility indicative of compliance with the opacity standard. For testing performed as part of this site-specific monitoring plan, the permitting authority may require as an alternative to the notification and reporting requirements specified in §§ 60.8 and 60.11 that the owner or operator submit any deviations with the excess emissions report required under § 60.51Da(d).

(ii) The owner or operator of the affected facility installs, calibrates, operates, and maintains a particulate matter continuous parametric monitoring system (PM CPMS) according to the requirements specified in subpart UUUUU of part 63.

* * * * *

(b) The owner or operator of an affected facility must install, calibrate, maintain, and operate a CEMS, and record the output of the system, for measuring SO_2 emissions, except where only gaseous and/or liquid fuels (excluding residual oil) where the potential SO_2 emissions rate of each fuel is 26 ng/J (0.060 lb/MMBtu) or less are combusted, as follows:

* * * * *

(t) The owner or operator of an affected facility demonstrating compliance with the output-based emissions limit under § 60.42Da must either install, certify, operate, and maintain a CEMS for measuring PM emissions according to the requirements of paragraph (v) of this section or install, calibrate, operate, and maintain a PM CPMS according to the requirements for new facilities specified in subpart UUUUU of part 63 of this chapter. An owner or operator of an affected facility demonstrating compliance with the input-based emissions limit in § 60.42Da may install, certify, operate, and maintain a CEMS for measuring PM emissions according to the requirements of paragraph (v) of this section.

* * * * *

■ 6. Revise § 60.50Da(f) to read as follows:

§ 60.50Da Compliance determination procedures and methods.

* * * * *

(f) The owner or operator of an electric utility combined cycle gas turbine that does not meet the definition of an IGCC must conduct performance tests for PM, SO_2, and NO_X using the procedures of Method 19 of appendix A–7 of this part. The SO_2 and NO_X emission rates calculations from the gas turbine used in Method 19 of appendix A–7 of this part are determined when the gas turbine is performance tested under subpart GG of this part. The potential uncontrolled PM emission rate from a gas turbine is defined as 17 ng/J (0.04 lb/MMBtu) heat input.

* * * * *

PART 63—NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS FOR SOURCE CATEGORIES

■ 7. The authority citation for 40 CFR Part 63 continues to read as follows:

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

■ 8. In § 63.9982, revise paragraphs (a) introductory text, (b), and (c) to read as follows:

§ 63.9982 What is the affected source of this subpart?

(a) This subpart applies to each individual or group of two or more new, reconstructed, or existing affected source(s) as described in paragraphs (a)(1) and (2) of this section within a contiguous area and under common control.

* * * * *

(b) An EGU is new if you commence construction of the coal- or oil-fired EGU after May 3, 2011.

(c) An EGU is reconstructed if you meet the reconstruction criteria as defined in § 63.2, and if you commence reconstruction after May 3, 2011.

* * * * *

■ 9. In § 63.10000, revise paragraphs (c)(1)(iv) and (c)(2)(ii) to read as follows:

§ 63.10000 What are my general requirements for complying with this subpart?

* * * * *

(c) * * *

(1) * * *

(iv) If your coal-fired or solid oil derived fuel-fired EGU or IGCC EGU does not qualify as a LEE for total non-mercury HAP metals, individual non-mercury HAP metals, or filterable particulate matter (PM), you must demonstrate compliance through an initial performance test and you must monitor continuous performance through either use of a particulate matter continuous parametric monitoring system (PM CPMS), a PM CEMS, or, for an existing EGU, compliance performance testing repeated quarterly.

* * * * *

(c) * * *

(2) * * *

(ii) If your liquid oil-fired unit does not qualify as a LEE for total HAP metals (including mercury), individual metals (including mercury), or filterable PM you must demonstrate compliance through an initial performance test and you must monitor continuous performance through either use of a PM CPMS, a PM CEMS, or, for an existing EGU, performance testing conducted quarterly.

* * * * *

■ 10. Amend § 63.10005 by:

■ a. Revising paragraphs (d)(2)(ii), (i)(4)(ii) and (i)(5);

■ b. Adding paragraph (i)(6).

The revised and added text read as follows:

§ 63.10005 What are my initial compliance requirements and by what date must I conduct them?

* * * * *

(d) * * *

(2) * * *

(ii) You must demonstrate continuous compliance with the PM CPMS site-specific operating limit that corresponds to the results of the performance test

demonstrating compliance with the emission limit with which you choose to comply.

* * * * *

(i) * * *

(4) * * *

(ii) ASTM D4006–11, ''Standard Test Method for Water in Crude Oil by Distillation,'' including Annex A1 and Appendix A1.

* * * * *

(5) Use one of the following methods to obtain fuel moisture samples:

(i) ASTM D4177–95 (Reapproved 2010), ''Standard Practice for Automatic Sampling of Petroleum and Petroleum Products,'' including Annexes A1 through A6 and Appendices X1 and X2, or

(ii) ASTM D4057–06 (Reapproved 2011), ''Standard Practice for Manual Sampling of Petroleum and Petroleum Products,'' including Annex A1.

(6) Should the moisture in your liquid fuel be more than 1.0 percent by weight, you must

(i) Conduct HCl and HF emissions testing quarterly (and monitor site-specific operating parameters as provided in § 63.10000(c)(2)(iii) or

(ii) Use an HCl CEMS and/or HF CEMS.

* * * * *

■ 11. In § 63.10006, revise paragraph (c) to read as follows:

§ 63.10006 When must I conduct subsequent performance tests or tune-ups?

* * * * *

(c) Except where paragraphs (a) or (b) of this section apply, or where you install, certify, and operate a PM CEMS to demonstrate compliance with a filterable PM emissions limit, for liquid oil-, solid oil-derived fuel-, coal-fired and IGCC EGUs, you must conduct all applicable periodic emissions tests for filterable PM, individual, or total HAP metals emissions according to Table 5 to this subpart, § 63.10007, and § 63.10000(c), except as otherwise provided in § 63.10021(d)(1).

* * * * *

■ 12. In § 63.10007, revise paragraph (c) to read as follows:

§ 63.10007 What methods and other procedures must I use for the performance tests?

* * * * *

(c) If you choose the filterable PM method to comply with the PM emission limit and demonstrate continuous performance using a PM CPMS as provided for in § 63.10000(c), you must also establish an operating limit according to § 63.10011(b), § 63.10023, and Tables 4 and 6 to this subpart. Should you desire to have operating limits that correspond to loads other than maximum normal operating load, you must conduct testing at those other loads to determine the additional operating limits.

* * * * *

■ 13. In § 63.10009, revise paragraphs (b)(2) and (b)(3) to read as follows:

§ 63.10009 May I use emissions averaging to comply with this subpart?

* * * * *

(b) * * *

(2) Weighted 30-boiler operating day rolling average emissions rate equations for pollutants other than Hg. Use equation 2a or 2b to calculate the 30 day rolling average emissions daily.

$$WAER = \frac{\sum_{i=1}^{p}\left[\sum_{i=1}^{n}(Her_i \times Rm_i)\right]_p + \sum_{i=1}^{m}(Ter_i \times Rt_i)}{\sum_{i=1}^{p}\left[\sum_{i=1}^{n}(Rm_i)\right]_p + \sum_{i=1}^{m} Rt_i} \quad (Eq.2a)$$

Where:

Her_i = hourly emission rate (e.g., lb/MMBtu, lb/MWh) from unit i's CEMS for the preceding 30-group boiler operating days,

Rm_i = hourly heat input or gross electrical output from unit i for the preceding 30-group boiler operating days,

p = number of EGUs in emissions averaging group that rely on CEMS or sorbent trap monitoring,

n = number of hourly rates collected over 30-group boiler operating days,

Ter_i = Emissions rate from most recent emissions test of unit i in terms of lb/heat input or lb/gross electrical output,

Rt_i = Total heat input or gross electrical output of unit i for the preceding 30-boiler operating days, and

m = number of EGUs in emissions averaging group that rely on emissions testing.

$$WAER = \frac{\sum_{i=1}^{p}\left[\sum_{i=1}^{n}(Her_i \times Sm_i \times Cfm_i)\right]_p + \sum_{i=1}^{m}(Ter_i \times St_i \times Cft_i)}{\sum_{i=1}^{p}\left[\sum_{i=1}^{n}(Sm_i \times Cfm_i)\right]_p + \sum_{i=1}^{m} St_i \times Cft_i} \quad (Eq.2b)$$

Where:

variables with similar names share the descriptions for Equation 2a,

Sm_i = steam generation in units of pounds from unit i that uses CEMS for the preceding 30-group boiler operating days,

Cfm_i = conversion factor, calculated from the most recent compliance test results, in units of heat input per pound of steam generated or gross electrical output per pound of steam generated, from unit i that uses CEMS from the preceding 30 group boiler operating days,

St_i = steam generation in units of pounds from unit i that uses emissions testing, and

Cft_i = conversion factor, calculated from the most recent compliance test results, in units of heat input per pound of steam generated or gross electrical output per pound of steam generated, from unit i that uses emissions testing.

(3) Weighted 90-boiler operating day rolling average emissions rate equations for Hg emissions from EGUs in the ''coal-fired unit not low rank virgin coal'' subcategory. Use equation 3a or 3b to calculate the 90-day rolling average emissions daily.

$$WAER = \frac{\sum_{i=1}^{p}\left[\sum_{i=1}^{n}(Her_i \times Rm_i)\right]_p + \sum_{i=1}^{m}(Ter_i \times Rt_i)}{\sum_{i=1}^{p}\left[\sum_{i=1}^{n}(Rm_i)\right]_p + \sum_{i=1}^{m} Rt_i} \quad (Eq.3a)$$

Where:

Her_i = hourly emission rate from unit i's CEMS or Hg sorbent trap monitoring system for the preceding 90-group boiler operating days,

Rm_i = hourly heat input or gross electrical output from unit i for the preceding 90-group boiler operating days,

p = number of EGUs in emissions averaging group that rely on CEMS,

n = number of hourly rates collected over the 90-group boiler operating days,

Ter_i = Emissions rate from most recent emissions test of unit i in terms of lb/heat input or lb/gross electrical output,

Rt_i = Total heat input or gross electrical output of unit i for the preceding 90-boiler operating days, and

m = number of EGUs in emissions averaging group that rely on emissions testing.

$$WAER = \frac{\sum_{i=1}^{p}\left[\sum_{i=1}^{n}(Her_i \times Sm_i \times Cfm_i)\right]_p + \sum_{i=1}^{m}(Ter_i \times St_i \times Cft_i)}{\sum_{i=1}^{p}\left[\sum_{i=1}^{n}(Sm_i \times Cfm_i)\right]_p + \sum_{i=1}^{m} St_i \times Cft_i} \quad (Eq.3b)$$

Where:

variables with similar names share the descriptions for Equation 2a,

Sm_i = steam generation in units of pounds from unit i that uses CEMS or a Hg sorbent trap monitoring for the preceding 90-group boiler operating days,

Cfm_i = conversion factor, calculated from the most recent compliance test results, in units of heat input per pound of steam generated or gross electrical output per pound of steam generated, from unit i that uses CEMS or sorbent trap monitoring from the preceding 90-group boiler operating days,

St_i = steam generation in units of pounds from unit i that uses emissions testing, and

Cft_i = conversion factor, calculated from the most recent emissions test results, in units of heat input per pound of steam generated or gross electrical output per pound of steam generated, from unit i that uses emissions testing.

* * * * *

■ 14. In § 63.10010, revise paragraph (j)(1)(i) to read as follows:

§ 63.10010 What are my monitoring, installation, operation, and maintenance requirements?

* * * * *

(j) * * *

(1) * * *

(i) Install and certify your HAP metals CEMS according to the procedures and requirements in your approved site-specific test plan as required in § 63.7(e). The reportable measurement output from the HAP metals CEMS must be expressed in units of the applicable emissions limit (*e.g.,* lb/MMBtu, lb/MWh) and in the form of a 30-boiler operating day rolling average.

* * * * *

■ 15. Amend § 63.10021 by adding paragraphs (c)(1) and (2) to read as follows:

§ 63.10021 How do I demonstrate continuous compliance with the emission limitations, operating limits, and work practice standards?

* * * * *

(c) * * *

(1) For any exceedance of the 30-boiler operating day PM CPMS average value from the established operating parameter limit for an EGU subject to the emissions limits in Table 1 to this subpart, you must:

(i) Within 48 hours of the exceedance, visually inspect the air pollution control device (APCD);

(ii) If the inspection of the APCD identifies the cause of the exceedance, take corrective action as soon as possible, and return the PM CPMS measurement to within the established value; and

(iii) Within 45 days of the exceedance or at the time of the annual compliance test, whichever comes first, conduct a PM emissions compliance test to determine compliance with the PM emissions limit and to verify or re-establish the CPMS operating limit. You are not required to conduct any additional testing for any exceedances that occur between the time of the original exceedance and the PM emissions compliance test required under this paragraph.

(2) PM CPMS exceedances of the operating limit for an EGU subject to the emissions limits in Table 1 of this subpart leading to more than four required performance tests in a 12-month period (rolling monthly) constitute a separate violation of this subpart.

* * * * *

■ 16. In § 63.10023, revise paragraph (b) to read as follows:

§ 63.10023 How do I establish my PM CPMS operating limit and determine compliance with it?

* * * * *

(b) Determine your operating limit as provided in paragraph (b)(1) or (b)(2) of this section. You must verify an existing or establish a new operating limit after each repeated performance test.

(1) For an existing EGU, determine your operating limit based on the highest 1-hour average PM CPMS output value recorded during the performance test.

(2) For a new EGU, determine your operating limit as follows.

(i) If your PM performance test demonstrates your PM emissions do not exceed 75 percent of your emissions limit, you will use the average PM CPMS value recorded during the PM compliance test, the milliamp equivalent of zero output from your PM CPMS, and the average PM result of your compliance test to establish your operating limit. Calculate the operating limit by establishing a relationship of PM CPMS signal to PM concentration using the PM CPMS instrument zero, the average PM CPMS values corresponding to the three compliance test runs, and the average PM concentration from the Method 5 compliance test with the procedures in (b)(2)(i)(A) through (D) of this section.

(A) Determine your PM CPMS instrument zero output with one of the following procedures.

(*1*) Zero point data for in-situ instruments should be obtained by removing the instrument from the stack and monitoring ambient air on a test bench.

(*2*) Zero point data for extractive instruments should be obtained by removing the extractive probe from the stack and drawing in clean ambient air.

(*3*) The zero point can also can be obtained by performing manual reference method measurements when the flue gas is free of PM emissions or contains very low PM concentrations (e.g., when your process is not operating, but the fans are operating or your source is combusting only natural gas) and plotting these with the compliance data to find the zero intercept.

(*4*) If none of the steps in paragraphs (A)(*1*) through (*3*) of this section are possible, you must use a zero output value provided by the manufacturer.

(B) Determine your PM CPMS instrument average (*x*) in milliamps, and the average of your corresponding three PM compliance test runs (*y*), using equation 10.

$$\bar{x} = \frac{1}{n}\sum_{i=1}^{n} X_i, \bar{y} = \frac{1}{n}\sum_{i=1}^{n} Y_i \qquad \text{(Eq. 10)}$$

Where:

X_i = the PM CPMS data points for run i of the performance test,

Y_i = the PM emissions value (in lb/MWh) for run i of the performance test, and

n = the number of data points.

(C) With your PM CPMS instrument zero expressed in milliamps, your three run average PM CPMS milliamp value, and your three run average PM emissions value (in lb/MWh) from your compliance runs, determine a relationship of PM lb/MWh per milliamp with equation 11.

$$R = \frac{\bar{y}}{(\bar{x} - z)} \qquad \text{(Eq. 11)}$$

Where:

R = the relative PM lb/MWh per milliamp for your PM CPMS,

$\bar{y}$ = the three run average PM lb/MWh,

$\bar{x}$ = the three run average milliamp output from your PM CPMS, and

z = the milliamp equivalent of your instrument zero determined from (b)(2)(i)(A) of this section.

(D) Determine your source specific 30-day rolling average operating limit using the PM lb/MWh per milliamp value from equation 11 in equation 12, below. This sets your operating limit at the PM CPMS output value corresponding to 75 percent of your emission limit.

$$O_L = z + \frac{(0.75 \times L)}{R} \qquad \text{(Eq. 12)}$$

Where:

O_L = the operating limit for your PM CPMS on a 30-day rolling average, in milliamps,

L = your source PM emissions limit in lb/MWh,

z = your instrument zero in milliamps, determined from (b)(2)(i)(A) of this section, and

R = the relative PM lb/MWh per milliamp for your PM CPMS, from equation 11.

(ii) If your PM compliance test demonstrates your PM emissions exceed 75 percent of your emissions limit, you will use the average PM CPMS value recorded during the PM compliance test demonstrating compliance with the PM limit to establish your operating limit.

(A) Determine your operating limit by averaging the PM CPMS milliamp output corresponding to your three PM performance test runs that demonstrate compliance with the emission limit using equation 13.

$$O_h = \frac{1}{n}\sum_{i=1}^{n} X_i \qquad \text{(Eq. 13)}$$

Where:

X_i = the PM CPMS data points for all runs i,

n = the number of data points, and

O_h = your site specific operating limit, in milliamps.

(iii) Your PM CPMS must provide a 4–20 milliamp output and the establishment of its relationship to manual reference method measurements must be determined in units of milliamps.

(iv) Your PM CPMS operating range must be capable of reading PM concentrations from zero to a level equivalent to two times your allowable emission limit. If your PM CPMS is an auto-ranging instrument capable of multiple scales, the primary range of the instrument must be capable of reading PM concentration from zero to a level equivalent to two times your allowable emission limit.

(v) During the initial performance test or any such subsequent performance test that demonstrates compliance with the PM limit, record and average all milliamp output values from the PM CPMS for the periods corresponding to the compliance test runs.

(vi) For PM performance test reports used to set a PM CPMS operating limit, the electronic submission of the test report must also include the make and model of the PM CPMS instrument, serial number of the instrument, analytical principle of the instrument (e.g. beta attenuation), span of the instruments primary analytical range, milliamp value equivalent to the instrument zero output, technique by which this zero value was determined, and the average milliamp signal corresponding to each PM compliance test run.

* * * * *

■ 17. In § 63.10030, revise paragraphs (b), (c), and (d) to read as follows:

§ 63.10030 What notifications must I submit and when?

* * * * *

(b) As specified in § 63.9(b)(2), if you startup your EGU that is an affected source before April 16, 2012, you must submit an Initial Notification not later than 120 days after April 16, 2012.

(c) As specified in § 63.9(b)(4) and (b)(5), if you startup your new or reconstructed EGU that is an affected source on or after April 16, 2012, you must submit an Initial Notification not later than 15 days after the actual date of startup of the EGU that is an affected source.

(d) When you are required to conduct a performance test, you must submit a Notification of Intent to conduct a performance test at least 30 days before the performance test is scheduled to begin.

* * * * *

■ 18. Amend § 63.10042 by revising the definition of ''Unit designed for coal > 8,300 Btu/lb subcategory'' to read as follows:

§ 63.10042 What definitions apply to this subpart?

* * * * *

Unit designed for coal ≥ 8,300 Btu/lb subcategory means any coal-fired EGU that is not a coal-fired EGU in the ''unit designed for low rank virgin coal'' subcategory.

* * * * *

■ 19. Revise Table 1 to Subpart UUUUU of Part 63 to read as follows:

TABLE 1 TO SUBPART UUUUU OF PART 63—EMISSION LIMITS FOR NEW OR RECONSTRUCTED EGUS

[As stated in § 63.9991, you must comply with the following applicable emission limit]

If your EGU is in this subcategory	For the following pollutants	You must meet the following emission limits and work practice standards	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5
1. Coal-fired unit not low rank virgin coal.	a. Filterable particulate matter (PM).	9.0E–2 lb/MWh[1]	Collect a minimum of 4 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	6.0E–2 lb/GWh	Collect a minimum of 4 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E–3 lb/GWh.	
	Arsenic (As)	3.0E–3 lb/GWh.	
	Beryllium (Be)	6.0E–4 lb/GWh.	
	Cadmium (Cd)	4.0E–4 lb/GWh.	
	Chromium (Cr)	7.0E–3 lb/GWh.	
	Cobalt (Co)	2.0E–3 lb/GWh.	
	Lead (Pb)	2.0E–2 lb/GWh.	
	Manganese (Mn)	4.0E–3 lb/GWh.	
	Nickel (Ni)	4.0E–2 lb/GWh.	
	Selenium (Se)	5.0E–2 lb/GWh.	
	b. Hydrogen chloride (HCl)	1.0E–2 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348–03[2] or Method 320, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO_2)[3]	1.0 lb/MWh	SO_2 CEMS.
	c. Mercury (Hg)	3.0E–3 lb/GWh	Hg CEMS or sorbent trap monitoring system only.
2. Coal-fired units low rank virgin coal.	a. Filterable particulate matter (PM).	9.0E–2 lb/MWh[1]	Collect a minimum of 4 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	6.0E–2 lb/GWh	Collect a minimum of 4 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E–3 lb/GWh.	
	Arsenic (As)	3.0E–3 lb/GWh.	
	Beryllium (Be)	6.0E–4 lb/GWh.	
	Cadmium (Cd)	4.0E–4 lb/GWh.	
	Chromium (Cr)	7.0E–3 lb/GWh.	
	Cobalt (Co)	2.0E–3 lb/GWh.	
	Lead (Pb)	2.0E–2 lb/GWh.	
	Manganese (Mn)	4.0E–3 lb/GWh.	
	Nickel (Ni)	4.0E–2 lb/GWh.	
	Selenium (Se)	5.0E–2 lb/GWh.	
	b. Hydrogen chloride (HCl)	1.0E–2 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348–03[2] or Method 320, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO_2)[3]	1.0 lb/MWh	SO_2 CEMS.
	c. Mercury (Hg)	4.0E–2 lb/GWh	Hg CEMS or sorbent trap monitoring system only.
3. IGCC unit	a. Filterable particulate matter (PM).	7.0E–2 lb/MWh[4] 9.0E–2 lb/MWh[5]	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	4.0E–1 lb/GWh	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 2 dscm per run.
	Antimony (Sb)	2.0E–2 lb/GWh.	
	Arsenic (As)	2.0E–2 lb/GWh.	
	Beryllium (Be)	1.0E–3 lb/GWh.	
	Cadmium (Cd)	2.0E–3 lb/GWh.	
	Chromium (Cr)	4.0E–2 lb/GWh.	

TABLE 1 TO SUBPART UUUUU OF PART 63—EMISSION LIMITS FOR NEW OR RECONSTRUCTED EGUS—Continued

[As stated in § 63.9991, you must comply with the following applicable emission limit]

If your EGU is in this subcategory	For the following pollutants	You must meet the following emission limits and work practice standards	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5
	Cobalt (Co)	4.0E–3 lb/GWh.	
	Lead (Pb)	9.0E–3 lb/GWh.	
	Manganese (Mn)	2.0E–2 lb/GWh.	
	Nickel (Ni)	7.0E–2 lb/GWh.	
	Selenium (Se)	3.0E–1 lb/GWh.	
	b. Hydrogen chloride (HCl)	2.0E–3 lb/MWh	For Method 26A, collect a minimum of 1 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348–03[2] or Method 320, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO_2)[3]	4.0E–1 lb/MWh	SO_2 CEMS.
	c. Mercury (Hg)	3.0E–3 lb/GWh	Hg CEMS or sorbent trap monitoring system only.
4. Liquid oil-fired unit—continental (excluding limited-use liquid oil-fired subcategory units).	a. Filterable particulate matter (PM).	3.0E–1 lb/MWh[1]	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total HAP metals	2.0E–4 lb/MWh	Collect a minimum of 2 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 2 dscm per run.
	Antimony (Sb)	1.0E–2 lb/GWh.	
	Arsenic (As)	3.0E–3 lb/GWh.	
	Beryllium (Be)	5.0E–4 lb/GWh.	
	Cadmium (Cd)	2.0E–4 lb/GWh.	
	Chromium (Cr)	2.0E–2 lb/GWh.	
	Cobalt (Co)	3.0E–2 lb/GWh.	
	Lead (Pb)	8.0E–3 lb/GWh.	
	Manganese (Mn)	2.0E–2 lb/GWh.	
	Nickel (Ni)	9.0E–2 lb/GWh.	
	Selenium (Se)	2.0E–2 lb/GWh.	
	Mercury (Hg)	1.0E–4 lb/GWh	For Method 30B sample volume determination (Section 8.2.4), the estimated Hg concentration should nominally be < ½ the standard.
	b. Hydrogen chloride (HCl)	4.0E–4 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348–03[2] or Method 320, sample for a minimum of 1 hour.
	c. Hydrogen fluoride (HF)	4.0E–4 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348–03[2] or Method 320, sample for a minimum of 1 hour.
5. Liquid oil-fired unit—non-continental (excluding limited-use liquid oil-fired subcategory units).	a. Filterable particulate matter (PM).	2.0E–1 lb/MWh[1]	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total HAP metals	7.0E–3 lb/MWh	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E–3 lb/GWh.	
	Arsenic (As)	6.0E–2 lb/GWh.	
	Beryllium (Be)	2.0E–3 lb/GWh.	
	Cadmium (Cd)	2.0E–3 lb/GWh.	
	Chromium (Cr)	2.0E–2 lb/GWh.	
	Cobalt (Co)	3.0E–1 lb/GWh.	
	Lead (Pb)	3.0E–2 lb/GWh.	
	Manganese (Mn)	1.0E–1 lb/GWh.	

TABLE 1 TO SUBPART UUUUU OF PART 63—EMISSION LIMITS FOR NEW OR RECONSTRUCTED EGUS—Continued

[As stated in § 63.9991, you must comply with the following applicable emission limit]

If your EGU is in this subcategory	For the following pollutants	You must meet the following emission limits and work practice standards	Using these requirements, as appropriate (e.g., specified sampling volume or test run duration) and limitations with the test methods in Table 5
	Nickel (Ni)	4.1E0 lb/GWh.	
	Selenium (Se)	2.0E–2 lb/GWh.	
	Mercury (Hg)	4.0E–4 lb/GWh	For Method 30B sample volume determination (Section 8.2.4), the estimated Hg concentration should nominally be < ½ the standard.
	b. Hydrogen chloride (HCl)	2.0E–3 lb/MWh	For Method 26A, collect a minimum of 1 dscm per run; for Method 26, collect a minimum of 120 liters per run. For ASTM D6348–03[2] or Method 320, sample for a minimum of 1 hour.
	c. Hydrogen fluoride (HF)	5.0E–4 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348–03[2] or Method 320, sample for a minimum of 1 hour.
6. Solid oil-derived fuel-fired unit	a. Filterable particulate matter (PM).	3.0E–2 lb/MWh[1]	Collect a minimum of 1 dscm per run.
	OR	OR	
	Total non-Hg HAP metals	6.0E–1 lb/GWh	Collect a minimum of 1 dscm per run.
	OR	OR	
	Individual HAP metals:		Collect a minimum of 3 dscm per run.
	Antimony (Sb)	8.0E–3 lb/GWh.	
	Arsenic (As)	3.0E–3 lb/GWh.	
	Beryllium (Be)	6.0E–4 lb/GWh.	
	Cadmium (Cd)	7.0E–4 lb/GWh.	
	Chromium (Cr)	6.0E–3 lb/GWh.	
	Cobalt (Co)	2.0E–3 lb/GWh.	
	Lead (Pb)	2.0E–2 lb/GWh.	
	Manganese (Mn)	7.0E–3 lb/GWh.	
	Nickel (Ni)	4.0E–2 lb/GWh.	
	Selenium (Se)	6.0E–3 lb/GWh.	
	b. Hydrogen chloride (HCl)	4.0E–4 lb/MWh	For Method 26A, collect a minimum of 3 dscm per run. For ASTM D6348–03[2] or Method 320, sample for a minimum of 1 hour.
	OR		
	Sulfur dioxide (SO_2)[3]	1.0 lb/MWh	SO_2 CEMS.
	c. Mercury (Hg)	2.0E–3 lb/GWh	Hg CEMS or Sorbent trap monitoring system only.

[1] Gross electric output.
[2] Incorporated by reference, see § 63.14.
[3] You may not use the alternate SO_2 limit if your EGU does not have some form of FGD system (or, in the case of IGCC EGUs, some other acid gas removal system either upstream or downstream of the combined cycle block) and SO_2 CEMS installed.
[4] Duct burners on syngas; gross electric output.
[5] Duct burners on natural gas; gross electric output.

■ 20. Revise Table 4 to Subpart UUUUU of Part 63 to read as follows:

TABLE 4 TO SUBPART UUUUU OF PART 63—OPERATING LIMITS FOR EGUS

[As stated in §§ 63.9991, you must comply with the applicable operating limits]

If you demonstrate compliance using . . .	You must meet these operating limits . . .
1. PM CPMS for an existing EGU ..	Maintain the 30-boiler operating day rolling average PM CPMS output at or below the highest 1-hour average measured during the most recent performance test demonstrating compliance with the filterable PM, total non-mercury HAP metals (total HAP metals, for liquid oil-fired units), or individual non-mercury HAP metals (individual HAP metals including Hg, for liquid oil-fired units) emissions limitation(s).
2. PM CPMS for a new EGU	Maintain the 30-boiler operating day rolling average PM CPMS output determined in accordance with the requirements of § 63.10023(b)(2) and obtained during the most recent performance test run demonstrating compliance with the filterable PM, total non-mercury HAP metals (total HAP metals, for liquid oil-fired units), or individual non-mercury HAP metals (individual HAP metals including Hg, for liquid oil-fired units) emissions limitation(s).

■ 21. Revise footnote 4 of Table 5 to Subpart UUUUU of Part 63 to read as follows:

TABLE 5 TO SUBPART UUUUU OF PART 63—PERFORMANCE TESTING REQUIREMENTS

* * * * * * *

[4] When using ASTM D6348–03, the following conditions must be met: (1) The test plan preparation and implementation in the Annexes to ASTM D6348–03, Sections A1 through A8 are mandatory; (2) For ASTM D6348–03 Annex A5 (Analyte Spiking Technique), the percent (%)R must be determined for each target analyte (see Equation A5.5); (3) For the ASTM D6348–03 test data to be acceptable for a target analyte, %R must be 70% ≤ R ≤ 130%; and (4) The %R value for each compound must be reported in the test report and all field measurements corrected with the calculated %R value for that compound using the following equation:

■ 22. Revise Table 6 to Subpart UUUUU of Part 63 to read as follows:

TABLE 6 TO SUBPART UUUUU OF PART 63—ESTABLISHING PM CPMS OPERATING LIMITS

[As stated in § 63.10007, you must comply with the following requirements for establishing operating limits]

If you have an applicable emission limit for . . .	And you choose to establish PM CPMS operating limits, you must . . .	And . . .	Using . . .	According to the following procedures . . .
1. Filterable Particulate matter (PM), total non-mercury HAP metals, individual non-mercury HAP metals, total HAP metals, or individual HAP metals for an existing EGU.	Install, certify, maintain, and operate a PM CPMS for monitoring emissions discharged to the atmosphere according to § 63.10010(h)(1).	Establish a site-specific operating limit in units of PM CPMS output signal (*e.g.,* milliamps, mg/acm, or other raw signal).	Data from the PM CPMS and the PM or HAP metals performance tests.	1. Collect PM CPMS output data during the entire period of the performance tests. 2. Record the average hourly PM CPMS output for each test run in the three run performance test. 3. Determine the highest 1-hour average PM CPMS measured during the performance test demonstrating compliance with the filterable PM or HAP metals emissions limitations.

TABLE 6 TO SUBPART UUUUU OF PART 63—ESTABLISHING PM CPMS OPERATING LIMITS—Continued

[As stated in § 63.10007, you must comply with the following requirements for establishing operating limits]

If you have an applicable emission limit for . . .	And you choose to establish PM CPMS operating limits, you must . . .	And . . .	Using . . .	According to the following procedures . . .
2. Filterable Particulate matter (PM), total non-mercury HAP metals, individual non-mercury HAP metals, total HAP metals, or individual HAP metals for a new EGU.	Install, certify, maintain, and operate a PM CPMS for monitoring emissions discharged to the atmosphere according to § 63.10010(h)(1).	Establish a site-specific operating limit in units of PM CPMS output signal (*e.g.,* milliamps, mg/acm, or other raw signal).	Data from the PM CPMS and the PM or HAP metals performance tests.	1. Collect PM CPMS output data during the entire period of the performance tests. 2. Record the average hourly PM CPMS output for each test run in the performance test. 3. Determine the PM CPMS operating limit in accordance with the requirements of § 63.10023(b)(2) from data obtained during the performance test demonstrating compliance with the filterable PM or HAP metals emissions limitations.

■ 23. Revise Table 7 to Subpart UUUUU of Part 63 to read as follows:

TABLE 7 TO SUBPART UUUUU OF PART 63—DEMONSTRATING CONTINUOUS COMPLIANCE

[As stated in § 63.10021, you must show continuous compliance with the emission limitations for affected sources according to the following]

If you use one of the following to meet applicable emissions limits, operating limits, or work practice standards . . .	You demonstrate continuous compliance by . . .
1. CEMS to measure filterable PM, SO_2, HCl, HF, or Hg emissions, or using a sorbent trap monitoring system to measure Hg.	Calculating the 30- (or 90-) boiler operating day rolling arithmetic average emissions rate in units of the applicable emissions standard basis at the end of each boiler operating day using all of the quality assured hourly average CEMS or sorbent trap data for the previous 30- (or 90-) boiler operating days, excluding data recorded during periods of startup or shutdown.
2. PM CPMS to measure compliance with a parametric operating limit.	Calculating the 30- (or 90-) boiler operating day rolling arithmetic average of all of the quality assured hourly average PM CPMS output data (e.g., milliamps, PM concentration, raw data signal) collected for all operating hours for the previous 30- (or 90-) boiler operating days, excluding data recorded during periods of startup or shutdown.
3. Site-specific monitoring using CMS for liquid oil-fired EGUs for HCl and HF emission limit monitoring.	If applicable, by conducting the monitoring in accordance with an approved site-specific monitoring plan.
4. Quarterly performance testing for coal-fired, solid oil derived fired, or liquid oil-fired EGUs to measure compliance with one or more non-PM (or its alternative emission limits) applicable emissions limit in Table 1 or 2, or PM (or its alternative emission limits) applicable emissions limit in Table 2.	Calculating the results of the testing in units of the applicable emissions standard.
5. Conducting periodic performance tune-ups of your EGU(s).	Conducting periodic performance tune-ups of your EGU(s), as specified in § 63.10021(e).
6. Work practice standards for coal-fired, liquid oil-fired, or solid oil-derived fuel-fired EGUs during startup.	Operating in accordance with Table 3.
7. Work practice standards for coal-fired, liquid oil-fired, or solid oil-derived fuel-fired EGUs during shutdown.	Operating in accordance with Table 3.

■ 24. Revise Table 9 to Subpart UUUUU of Part 63 to read as follows:

TABLE 9 TO SUBPART UUUUU OF PART 63—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART UUUUU

[As stated in § 63.10040, you must comply with the applicable General Provisions according to the following]

Citation	Subject	Applies to subpart UUUUU
§ 63.1	Applicability	Yes.
§ 63.2	Definitions	Yes. Additional terms defined in § 63.10042.
§ 63.3	Units and Abbreviations	Yes.
§ 63.4	Prohibited Activities and Circumvention.	Yes.
§ 63.5	Preconstruction Review and Notification Requirements.	Yes.
§ 63.6(a), (b)(1)–(b)(5), (b)(7), (c), (f)(2)–(3), (g), (h)(2)–(h)(9), (i), (j).	Compliance with Standards and Maintenance Requirements.	Yes.
§ 63.6(e)(1)(i)	General Duty to minimize emissions.	No. See § 63.10000(b) for general duty requirement.
§ 63.6(e)(1)(ii)	Requirement to correct malfunctions ASAP.	No.
§ 63.6(e)(3)	SSM Plan requirements	No.
§ 63.6(f)(1)	SSM exemption	No.
§ 63.6(h)(1)	SSM exemption	No.
§ 63.7(a), (b), (c), (d), (e)(2)–(e)(9), (f), (g), and (h).	Performance Testing Requirements.	Yes.
§ 63.7(e)(1)	Performance testing	No. See § 63.10007.
§ 63.8	Monitoring Requirements	Yes.
63.8(c)(1)(i)	General duty to minimize emissions and CMS operation.	No. See § 63.10000(b) for general duty requirement.
§ 63.8(c)(1)(iii)	Requirement to develop SSM Plan for CMS.	No.
§ 63.8(d)(3)	Written procedures for CMS	Yes, except for last sentence, which refers to an SSM plan. SSM plans are not required.
§ 63.9	Notification requirements	Yes, except for the 60-day notification prior to conducting a performance test in § 63.9(d); instead use a 30-day notification period per § 63.10030(d).
§ 63.10(a), (b)(1), (c), (d)(1)–(2), (e), and (f).	Recordkeeping and Reporting Requirements.	Yes, except for the requirements to submit written reports under § 63.10(e)(3)(v).
§ 63.10(b)(2)(i)	Recordkeeping of occurrence and duration of startups and shutdowns.	No.
§ 63.10(b)(2)(ii)	Recordkeeping of malfunctions	No. See 63.10001 for recordkeeping of (1) occurrence and duration and (2) actions taken during malfunction.
§ 63.10(b)(2)(iii)	Maintenance records	Yes.
§ 63.10(b)(2)(iv)	Actions taken to minimize emissions during SSM.	No.
§ 63.10(b)(2)(v)	Actions taken to minimize emissions during SSM.	No.
§ 63.10(b)(2)(vi)	Recordkeeping for CMS malfunctions.	Yes.
§ 63.10(b)(2)(vii)–(ix)	Other CMS requirements	Yes.
§ 63.10(b)(3),and (d)(3)–(5)		No.
§ 63.10(c)(7)	Additional recordkeeping requirements for CMS—identifying exceedances and excess emissions.	Yes.
§ 63.10(c)(8)	Additional recordkeeping requirements for CMS—identifying exceedances and excess emissions.	Yes.
§ 63.10(c)(10)	Recording nature and cause of malfunctions.	No. See 63.10032(g) and (h) for malfunctions recordkeeping requirements.
§ 63.10(c)(11)	Recording corrective actions	No. See 63.10032(g) and (h) for malfunctions recordkeeping requirements.
§ 63.10(c)(15)	Use of SSM Plan	No.
§ 63.10(d)(5)	SSM reports	No. See 63.10021(h) and (i) for malfunction reporting requirements.
§ 63.11	Control Device Requirements	No.
§ 63.12	State Authority and Delegation	Yes.
§ 63.13–63.16	Addresses, Incorporation by Reference, Availability of Information, Performance Track Provisions.	Yes.
§ 63.1(a)(5), (a)(7)–(a)(9), (b)(2), (c)(3)–(4), (d), 63.6(b)(6), (c)(3), (c)(4), (d), (e)(2), (e)(3)(ii), (h)(3), (h)(5)(iv), 63.8(a)(3), 63.9(b)(3), (h)(4), 63.10(c)(2)–(4), (c)(9).	Reserved	No.

■ 25. Revise sections 4.1 and 5.2.2.2 to Appendix A to Subpart UUUUU of Part 63 to read as follows:

Appendix A to Subpart UUUUU—Hg Monitoring Provisions

* * * * *

4.1 *Certification Requirements.* All Hg CEMS and sorbent trap monitoring systems and the additional monitoring systems used to continuously measure Hg emissions in units of the applicable emissions standard in accordance with this appendix must be certified in a timely manner, such that the initial compliance demonstration is completed no later than the applicable date in § 63.9984(f).

* * * * *

5.2.2.2 The same RATA performance criteria specified in Table A–2 for Hg CEMS also apply to the annual RATAs of the sorbent trap monitoring system.

* * * * *

■ 26. Revise section 3.1.2.1.3 and the heading to section 5.3.4 to Appendix B to Subpart UUUUU of Part 63 to read as follows:

Appendix B to Subpart UUUUU—HCl and HF Monitoring Provisions

* * * * *

3.1.2.1.3 For the ASTM D6348–03 test data to be acceptable for a target analyte, %R must be 70% ≤ R ≤ 130%; and

* * * * *

5.3.3 *Conditional Data Validation*

* * *

* * * * *

[FR Doc. 2013–07859 Filed 4–23–13; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 180

[EPA–HQ–OPP–2012–0282; FRL–9384–2]

Azoxystrobin; Pesticide Tolerances

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: This regulation establishes tolerances for residues of azoxystrobin in or on multiple commodities discussed later in this document. Syngenta Crop Protection, LLC requested these tolerances under the Federal Food, Drug, and Cosmetic Act (FFDCA).

DATES: This regulation is effective April 24, 2013. Objections and requests for hearings must be received on or before June 24, 2013, and must be filed in accordance with the instructions provided in 40 CFR part 178 (see also Unit I.C. of the **SUPPLEMENTARY INFORMATION**).

ADDRESSES: The docket for these actions, identified by docket identification (ID) number EPA–HQ–OPP–2012–0282, is available at *http://www.regulations.gov* or at the Office of Pesticide Programs Regulatory Public Docket (OPP Docket) in the Environmental Protection Agency Docket Center (EPA/DC), EPA West Bldg., Rm. 3334, 1301 Constitution Ave. NW., Washington, DC 20460–0001. 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 OPP Docket is (703) 305–5805. Please review the visitor instructions and additional information about the docket available at *http://www.epa.gov/dockets.*

FOR FURTHER INFORMATION CONTACT: Erin Malone, Registration Division (7505P), Office of Pesticide Programs, Environmental Protection Agency, 1200 Pennsylvania Ave. NW., Washington, DC 20460–0001; telephone number: (703) 347–0253; email address: *Malone.Erin@epa.gov.*

SUPPLEMENTARY INFORMATION:

I. General Information

A. Does this action apply to me?

You may be potentially affected by this action if you are an agricultural producer, food manufacturer, or pesticide manufacturer. The following list of North American Industrial Classification System (NAICS) codes is not intended to be exhaustive, but rather provides a guide to help readers determine whether this document applies to them. Potentially affected entities may include:

- Crop production (NAICS code 111).
- Animal production (NAICS code 112).
- Food manufacturing (NAICS code 311).
- Pesticide manufacturing (NAICS code 32532).

B. How can I get electronic access to other related information?

You may access a frequently updated electronic version of EPA's tolerance regulations at 40 CFR part 180 through the Government Printing Office's eCFR site at *http://www.ecfr.gov/cgi-bin/text-idx?&c=ecfr&tpl=/ecfrbrowse/Title40/40tab_02.tpl.*

C. How can I file an objection or hearing request?

Under FFDCA section 408(g), 21 U.S.C. 346a, any person may file an objection to any aspect of this regulation and may also request a hearing on those objections. You must file your objection or request a hearing on this regulation in accordance with the instructions provided in 40 CFR part 178. To ensure proper receipt by EPA, you must identify docket ID number EPA–HQ–OPP–2012–0282 in the subject line on the first page of your submission. All objections and requests for a hearing must be in writing, and must be received by the Hearing Clerk on or before June 24, 2013. Addresses for mail and hand delivery of objections and hearing requests are provided in 40 CFR 178.25(b).

In addition to filing an objection or hearing request with the Hearing Clerk as described in 40 CFR part 178, please submit a copy of the filing (excluding any Confidential Business Information (CBI)) for inclusion in the public docket. Information not marked confidential pursuant to 40 CFR part 2 may be disclosed publicly by EPA without prior notice. Submit the non-CBI copy of your objection or hearing request, identified by docket ID number EPA–HQ–OPP–2012–0282, by one of the following methods:

- *Federal eRulemaking Portal: http://www.regulations.gov.* Follow the online instructions for submitting comments. Do not submit electronically any information you consider to be CBI or other information whose disclosure is restricted by statute.
- *Mail:* OPP Docket, Environmental Protection Agency Docket Center (EPA/DC), (28221T), 1200 Pennsylvania Ave. NW., Washington, DC 20460–0001.
- *Hand Delivery:* To make special arrangements for hand delivery or delivery of boxed information, please follow the instructions at *http://www.epa.gov/dockets/contacts.htm.*

Additional instructions on commenting or visiting the docket, along with more information about dockets generally, is available at *http://www.epa.gov/dockets.*

II. Summary of Petitioned-For Tolerance

In the **Federal Register** of April 4, 2012 (77 FR 20336) (FRL–9340–4), EPA issued a document pursuant to FFDCA section 408(d)(3), 21 U.S.C. 346a(d)(3), announcing the filing of a pesticide petition (PP 1E7945) by Syngenta Crop Protection, LLC, P.O. Box 18300, Greensboro, NC 27419–8300. The petition requested that 40 CFR 180.507 be amended by establishing an import tolerance for residues of the fungicide azoxystrobin, [methyl(E)-2-(2-(6-(2-cyanophenoxy) pyrimidin-4-yloxy)phenyl)-3-methoxyacrylate], and the *Z*-isomer of azoxystrobin, [methyl(*Z*)-2-(2-(6-(2-