# WEST VIRGINIA
# SECRETARY OF STATE
## Betty Ireland
# ADMINISTRATIVE LAW DIVISION

Form #1

**Do Not Mark In This Box**

2008 JUL -9 A

45

## NOTICE OF A PUBLIC HEARING ON A PROPOSED RULE

AGENCY: WV Department of Environmental Protection, Division of Air Quality TITLE NUMBER: 45

RULE TYPE: Legislative CITE AUTHORITY: _____

AMENDMENT TO AN EXISTING RULE: YES [X] NO [ ]

IF YES, SERIES NUMBER OF RULE BEING AMENDED: 45CSR16

TITLE OF RULE BEING AMENDED: Standards of Performance for New Stationary Sources

IF NO, SERIES NUMBER OF RULE BEING PROPOSED: _____

TITLE OF RULE BEING PROPOSED: _____

DATE OF PUBLIC HEARING: Monday, August 11, 2008 TIME: 6:00 p.m.

LOCATION OF PUBLIC HEARING: WV Department of Environmental Protection
Coopers Rock Conference Room
601 57th Street, S.E.
Charleston, WV 25304

COMMENTS LIMITED TO: ORAL [ ] WRITTEN [ ] BOTH [X]

DATE WRITTEN COMMENT PERIOD ENDS: Monday, August 11, 2008 TIME: At close of hearing

WRITTEN COMMENTS MAY BE MAILED TO:
Kathy Cosco, Public Information Office
WV Department of Environmental Protection
601 57th Street, S.E.
Charleston, WV 25304

The Department requests that persons wishing to make comments at the hearing make an effort to submit written comments in order to facilitate the review of these comments.

The issues to be heard shall be limited to the proposed rule.

ATTACH A **BRIEF** SUMMARY OF YOUR PROPOSAL

Authorized Signature

# DEPARTMENT OF ENVIRONMENTAL PROTECTION
# DIVISION OF AIR QUALITY

# BRIEFING DOCUMENT

**Rule Title:** 45CSR16 - "Standards of Performance for New Stationary Sources"

## A. AUTHORITY: W.Va. Code §22-5-4

## B. SUMMARY OF RULE:

This rule establishes and adopts national standards of performance for new stationary sources and other regulatory requirements promulgated by the United States Environmental Protection Agency (U.S. EPA) pursuant to section 111(b) of the federal Clean Air Act, as amended (CAA). This rule codifies general procedures and criteria to implement standards of performance for new stationary sources set forth in 40 CFR Part 60. The rule also adopts associated appendices, reference methods, performance specifications and other test methods which are appended to such standards. Any person who constructs, modifies, reconstructs or operates an affected facility after the effective date of any NSPS under 40 CFR Part 60 must comply with the applicable NSPS and this rule.

## C. STATEMENT OF CIRCUMSTANCES WHICH REQUIRE RULE:

As set forth in 40 CFR §60.4(b), Section 111(c) of the CAA directs the U.S. EPA Administrator to delegate to each State the authority to implement and enforce standards of performance for new stationary sources. Promulgation of this rule will enable the State to continue to be the primary enforcement authority for the NSPS promulgated by U.S. EPA. Revisions to this rule are necessary to maintain consistency with current federal regulations, and to fulfill the State's responsibilities under the CAA. Revisions to the rule include annual incorporation by reference updates.

This revised rule incorporates by reference the following new or revised NSPS standards promulgated as of July 1, 2008: Update of Continuous Instrumental Test Methods: Technical Amendments; Amendments to New Source Performance Standards for Electric Utility Steam Generating Units and Industrial-Commercial-Institutional Steam Generating Units; and Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry; Equipment Leaks of VOC in Petroleum Refineries; and Standards of Performance for Petroleum Refineries.

## D. FEDERAL COUNTERPART REGULATIONS - INCORPORATION BY REFERENCE/DETERMINATION OF STRINGENCY:

A federal counterpart to this proposed rule exists. In accordance with the Secretary's recommendation, and with limited exception, the Division of Air Quality proposes that the rule incorporate by reference the federal counterparts. Because the proposed rule incorporates by reference the federal counterpart, no determination of stringency is required.

## E. CONSTITUTIONAL TAKINGS DETERMINATION:

In accordance with W.Va. Code §§22-1A-1 and 3(c), the Secretary has determined that this rule will not result in taking of private property within the meaning of the Constitutions of West Virginia and the United States of America.

## F. CONSULTATION WITH THE ENVIRONMENTAL PROTECTION ADVISORY COUNCIL:

At its June 24, 2008 meeting, the Environmental Protection Advisory Council reviewed and discussed this rule. (See attached minutes for Council's discussion).

West Virginia Department of Environmental Protection

**ADVISORY COUNCIL MEETING MINUTES**
Tuesday, June 24, 2008
601 57th Street, SE, Charleston, WV
West Virginia Room – 3rd Floor

**IN ATTENDANCE:**

***Members of the Council:***

Jackie Hallinan
Karen Price
Bill Raney
Rick Roberts

***DEP:***

| | |
|---|---|
| Randy Huffman | Cabinet Secretary |
| Lisa McClung | Deputy Cabinet Secretary and Director, Division of Water and Waste Management |
| Raymond Franks II | General Counsel |
| Karen Watson | Associate General Counsel |
| Kathy Cosco | Communications Director |
| Pam Nixon | Environmental Advocate |
| Ken Politan | Mining & Reclamation |
| Lewis Halstead | Mining & Reclamation |
| Charlie Sturey | Mining & Reclamation |
| Carroll Cather | Water & Waste Management |
| Don Martin | Land Restoration |
| Brian Long | Water & Waste Management |
| Dan Arnold | Water & Waste Management |
| Mike Zeto | Environmental Enforcement |
| Terrie Sangid | Water & Waste Management |
| Jim Mason | Air Quality |
| Mike Johnson | Water & Waste Management |
| Kathy Emery | Water & Waste Management |
| Scott Mandirola | Water & Waste Management |

***Visitors:***

| | |
|---|---|
| Tom Boggs | Chamber of Commerce |
| Don Garvin | WV Environmental Council |
| Ruth Lemmon | WV Auto/Truck Dealers Association |

**OLD BUSINESS:**

Secretary Huffman called the meeting to order at 1:35 p.m., and he announced that Members Lisa Dooley and Larry Harris would not be attending. On motion made by Mr. Raney and seconded by Ms. Hallinan, the Council approved the minutes from the March 18, 2008 meeting. Secretary Huffman then ceded the floor to Mr. Franks.

**NEW BUSINESS:**

Mr. Franks noted that for the 2009 regular legislative session, DEP was proposing changes to 20 rules, grouped by Division for presentation to the Council. Depending on who had shepherded the rule through its initial drafting, either Mr. Franks or Ms. Watson would lead the discussion, with program administrators available to assist in answering the Council's questions.

Ms. Watson presented 60 CSR 3, the "Brownfields" Rule. Ms. Watson explained that the Rule was currently pending before the Secretary of State for authorization as an emergency rule, and that the proposed changes included adjustments to the "de minimis" table and enhancing DEP's flexibility in obtaining risk assessments.

Ms. Price referred to a letter recently sent to DEP seeking clarification of the Rule's provisions concerning land use covenants and long-term maintenance agreements. Secretary Huffman stated that the letter would be retrieved and the issue noted for further consideration by the agency.

Mr. Raney inquired whether the Council could recommend changes to the rules as presented. Ms. Watson responded in the affirmative. Mr. Raney then asked whether written comments, such as those submitted by Mr. Harris prior to the meeting, would be appended to the minutes. Mr. Franks responded in the negative, and Ms. Watson expounded that Mr. Harris's comments would be summarized and addressed orally during the discussion of the particular rules involved.

Mr. Franks then presented 38 CSR 2, the Surface Mining Reclamation Rule. Mr. Franks explained that the proposed changes would expand the Secretary's oversight of "approved persons" authorized to render technical certifications contained within mining permit applications, and would clarify certain collateral activities as being within the scope of requests for incidental boundary revisions to existing permits. Mr. Franks also noted that the proposed Rule would set forth more relevant and exacting criteria for the Secretary to consider in evaluating applications for revisions.

Mr. Raney inquired generally about the provisions with respect to approved persons. Secretary Huffman replied that the increased oversight is necessary to improve the initial quality of the permit applications, such that the delays occasioned by subsequent corrections would be reduced or eliminated. Mr. Raney asked whether approved persons could include anyone other than engineers, and Mr. Halstead responded that the definition extended to surveyors and geologists. Mr. Raney noted the need to establish a procedure for suspension or revocation to limit the agency's unfettered discretion, to which Secretary Huffman and Mr. Franks replied that the Rule provided for notice and hearing prior to curtailing the privileges of anyone on the approved-person list.

Ms. Watson presented 47 CSR 30, establishing NPDES requirements for coal mining facilities. Ms. Watson explained that the proposed changes were relatively minor, designed to enhance consistency with the non-coal rule, to allow for digital signatures, and to permit correction of clerical errors.

The Council then considered the Air Quality rules. Mr. Franks presented 45 CSR 1 and 45 CSR 26, relating to control and reduction of nitrogen oxides from, respectively, non-electric and electric generating units, the latter by means of a budget trading program. The rules are to be repealed in their entireties, and Mr. Mason explained that both are being subsumed within the Clean Air Interstate Rule program.

Mr. Franks then presented 45 CSR 8, the Ambient Air Quality Rule. Mr. Franks explained that the 1-hour primary and secondary ozone standards were being replaced with 8-hour standards, with the maximum tolerance being reduced slightly. Mr. Raney inquired as to the practical effect of the proposed change, particularly with regard to whether non-compliance areas within the State might be expanded. Mr. Mason replied that an expansion might occur, but that it was difficult to predict at this early stage. Mr. Mason added that the time-period increase would inevitably lead to more accurate measurements.

Ms. Watson presented 45 CSR 13, governing permits for constructing and modifying non-major stationary sources of air pollutants. Ms. Watson explained that the Rule was being amended to reflect the recent statutory changes reducing the lag time for issuing permits and authorizing certain pre-permit construction. It was noted that Mr. Harris had submitted in writing his concern that courts would be loath to enforce agency cease-and-desist orders based on defects discovered during the permitting process after construction had already begun. Ms. Watson pointed out that the statute had been carefully crafted to avoid facile invocation of detrimental reliance, with Mr. Franks observing that the Rule strove to conform to the statute. Ms. Price wondered whether one or more of the timeframe provisions included within the existing Rule had been inadvertently omitted from the proposed version. Ms. Watson responded that the Rule had been carefully checked for completeness, but that she would once again verify the language to assure its accuracy.

Mr. Franks presented 45 CSR 14, governing permits for constructing and significantly modifying major stationary sources of air pollutants. Mr. Franks explained that references to pollution control projects and clean units were deleted in accordance with a federal appellate court decision vacating those provisions.

Mr. Franks went on to present 45 CSR 16, 45 CSR 25, and 45 CSR 34, relating respectively to performance standards for new stationary sources, pollution from hazardous waste treatment, storage, and disposal facilities, and emission standards for hazardous air pollutants. Mr. Mason noted that the changes incorporate revisions to the Rules' federal counterparts, except that some of the new standards were not incorporated within 45 CSR 34, because they constituted unfunded mandates. Mr. Garvin was recognized, and he asked whether the failure to incorporate equated to a lack of regulation. Mr. Mason responded in the negative, explaining that the monitoring and regulation would be performed by the federal government. Mr. Garvin inquired as to the affected industries, and Mr. Mason referred to a list including smaller gas facilities and paint-stripping shops.

Ms. Watson presented 45 CSR 37, detailing the budget trading program to reduce mercury emissions. Ms. Watson explained that the rule is being repealed as inconsistent with a federal appellate court decision, pending alternative action by the EPA. Mr. Garvin inquired whether the Rule repealed two years ago would be reinstated upon revocation of the current version, to which Ms. Watson and Mr. Franks replied that it would not, if there had indeed been a previous rule in place, which was somewhat in question. Mr. Mason explained that mercury emissions would be monitored and regulated as usual, except that budget trading would not be available as a method of reduction. He also stated that there have been discussions on a national level as to whether to reinstate the federal mercury monitoring requirements.

The Council then turned its attention to the Water and Waste Management Rules. Ms. Watson presented 33 CSR 20, governing hazardous waste management systems. Ms. Watson explained that the Rule incorporated by reference its federal counterpart, the most salient change to which is its attempt to reduce disposal by permitting facilities to stage hazardous waste for three days pending recycling. Mr. Raney asked whether three days was sufficient time, and Mr. Cather responded in the affirmative.

Mr. Franks presented 33 CSR 24, the Hazardous Waste Management Fee Rule. Mr. Franks explained that increases to the fee assessments are necessary to sustain the underlying Fund by ensuring sufficient matching revenue for federal grants. Ms. Price indicated her belief that, as part of the legislative compromise extending the fee's duration, no increases would be forthcoming until completion and review of the Fund's legislative audit. Secretary Huffman responded that the preliminary audit findings in no way indicate any misallocation within the Fund or contravene the agency's determination that fee increases are necessary. Ms. Lemmon was recognized, and she commented that the proposed increase was unfair to automobile and truck dealers, as well as other small generators. Ms. Lemmon suggested that a study be done to identify the industries causing DEP to incur program costs, with fee assessments to be made proportionately.

Ms. Watson presented 33 CSR 22 and 47 CSR 56, governing the assessment of civil administrative penalties for, respectively, hazardous and solid waste violations and violations relating to groundwater. Ms. Watson explained that the Rules were being modified for the first time since their initial promulgation, with the purpose of clarifying their application by listing additional factors to be considered in calculating penalties, providing ratings examples, and expanding facility categories.

Ms. Watson then presented 47 CSR 31, addressing the State Water Pollution Control Revolving Fund. Ms. Watson explained that the proposed changes include the creation of a state review process for sewer projects in lieu of a wholesale adoption of the federal requirements. Mr. Roberts observed that many of the eligibility criteria would be deleted, but Ms. Emery assured the Council that inasmuch as the criteria were not being uniformly met, the deletion would have no practical effect on the Fund's administration. Ms. Watson advised Mr. Roberts that if he continued to have concerns upon further review, he should submit written suggestions for changes during the formal comment period.

Mr. Franks presented 47 CSR 32, governing the certification of laboratories conducting analyses of waste and wastewater. Mr. Franks explained that the proposed changes are designed to modernize outdated procedures and protocols that have remained constant since 1995, and to increase program funding through increased certification fees and a new application fee. Mr. Raney asked whether the new fees would render the program self-sustaining, and Mr. Arnold replied that it would for the time-being. In response to further inquiry, Mr. Arnold stated that DEP conducts annual, on-site audits of commercial and industrial labs, with municipal labs typically audited every two years, depending on the experience of the support personnel.

Ms. Watson presented 47 CSR 34, the Dam Safety Rule. Ms. Watson explained that the Rule is being extensively augmented to govern disbursement and use of a new Revolving Fund to finance repair and rehabilitation of deficient dams. Secretary Huffman commented that it appeared imminent that the Legislature would approve a transfer of $350,000 from excess general revenue as seed money for the Fund.

Lastly, Ms. Watson presented 47 CSR 2, the Water Quality Standards Rule. Ms. Watson explained that the proposed revisions are designed to clarify the definition of Category A use, while providing specific standards to be applied in the permitting process to determine in a more streamlined fashion whether the use is unsuitable in cases of insufficient flow and hydrologic modification. Mr. Raney commented that the Category A determination process has always been a significant problem for the coal industry. Ms. Price also agreed for her members. Mr. Garvin noted that the environmental community had expressed some initial concern regarding the proposed streamlining mechanisms, but that there was some general support for taking the matter out of the legislative arena. Mr. Huffman affirmed that the revisions are designed solely for the benefit of the regulated public and that the revisions must include the clarification that Category A applies statewide.

Ms. Watson reported that the rules will proceed to be filed with the Secretary of State, some perhaps as early as the week following the Council meeting, and that some will have an extended 45-day comment period.

Mr. Franks requested closing comments from Council members and from the public. Following the cessation of discussion, Mr. Franks reminded the Council that the next meeting is scheduled for 1:30 p.m. on September 9, 2008.

Secretary Huffman declared the meeting adjourned at 3:25 p.m.

APPENDIX B

# *FISCAL NOTE FOR PROPOSED RULES*

Rule Title: 45CSR16 - "Standards of Performance for New Stationary Sources"

Type of Rule: ___X__ Legislative _____Interpretive _____Procedural

Agency: Division of Air Quality

Address: 601 57th Street SE

Charleston, WV 25304

Phone Number: 926-0475 Email: tmowrer@wvdep.org

## Fiscal Note Summary

Summarize in a clear and concise manner what impact this measure will have on costs and revenues of state government.

No impact above that resulting from currently applicable federal emission standards.

## Fiscal Note Detail

Show over-all effect in Item 1 and 2 and, in Item 3, give an explanation of Breakdown by fiscal year, including long-range effect.

**FISCAL YEAR**

| Effect of Proposal | 2009 Increase/Decrease (use "-") | 2010 Increase/Decrease (use "-") | Fiscal Year (Upon Full Implementation) |
|---|---|---|---|
| **1. Estimated Total Cost** | $ 0 | $ 0 | $ 0 |
| Personal Services | 0 | 0 | 0 |
| Current Expenses | 0 | 0 | 0 |
| Repairs & Alterations | 0 | 0 | 0 |
| Assets | 0 | 0 | 0 |
| Equipment | 0 | 0 | 0 |
| Other | 0 | 0 | 0 |
| **2. Estimated Total Revenues** | 0 | 0 | 0 |

Rule Title: 45CSR16 - "Standards of Performance for New Stationary Sources"

3. **Explanation of above estimates (including long-range effect):**
Please include any increase or decrease in fees in your estimated total revenues.

Costs anticipated to be incurred in the implementation of federal rules promulgated under 40 CFR Part 60 as of June 1, 2008 are included in prior cost estimates prepared for state implementation of Title V of the Clean Air Act, as amended, under 45CSR30. Full Title V program approval was issued by the U.S. Environmental Protection Agency on November 19, 2001.

## MEMORANDUM

Please identify any areas of vagueness, technical defects, reasons the proposed rule **would not** have a fiscal impact, and/or any special issues **not** captured elsewhere on this form.

# TITLE 45
# LEGISLATIVE RULE
# DEPARTMENT OF ENVIRONMENTAL PROTECTION
# ~~DIVISION OF~~ AIR QUALITY

## SERIES 16
## STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

### §45-16-1. General.

1.1. Scope. -- This rule establishes and adopts standards of performance for new stationary sources promulgated by the United States Environmental Protection Agency pursuant to section 111(b) of the federal Clean Air Act, as amended (CAA). This rule codifies general procedures and criteria to implement the standards of performance for new stationary sources set forth in 40 CFR Part 60. The Secretary hereby adopts these standards by reference. The Secretary also adopts associated reference methods, performance specifications and other test methods which are appended to these standards.

1.2. Authority. -- W.Va. Code §22-5-4.

1.3. Filing Date. -- ~~April 23, 2008~~.

1.4. Effective Date. -- ~~June 1, 2008~~.

1.5. Incorporation By Reference. -- Federal Counterpart Regulation. The Secretary has determined that a federal counterpart rule exists, and in accordance with the Secretary's recommendation, with limited exception, this rule incorporates by reference 40 CFR Parts 60 and 65, to the extent referenced in 40 CFR Part 60, ~~June 1, 2007~~ July 1, 2008.

1.6. Former Rules. -- This legislative rule amends 45CSR16 "Standards of Performance for New Stationary Sources ~~Pursuant to 40 CFR Part 60~~" which was filed ~~April 28, 2006~~ April 23, 2008, and which became effective ~~June 1, 2006~~ June 1, 2008.

### §45-16-2. Definitions.

2.1. "Administrator" means the Administrator of the United States Environmental Protection Agency or his or her authorized representative.

2.2. "Clean Air Act" ("CAA") means 42 U.S.C. §7401 et seq.

2.3. "Secretary" means the Secretary of the Department of Environmental Protection or other person to whom the Secretary has delegated authority or duties pursuant to W.Va. Code §§22-1-6 or 22-1-8.

2.4. Other words and phrases used in this rule, unless otherwise indicated, shall have the meaning ascribed to them in 40 CFR Part 60. Words and phrases not defined therein shall have the meaning given to them in the federal Clean Air Act.

### §45-16-3. Requirements.

3.1. No person may construct, reconstruct, modify, or operate or cause to be constructed, reconstructed, modified, or operated any source subject to the provisions of 40 CFR Part 60 which results or will result in a violation of this rule.

### §45-16-4. Adoption of Standards.

4.1. Standards. -- The Secretary hereby adopts and incorporates by reference the provisions of 40 CFR Parts 60 and 65, to the extent referenced in 40 CFR Part 60, including any reference methods, performance specifications and other test methods which are appended to

these standards and contained in 40 CFR Parts 60 and 65, effective ~~June 1, 2007~~ July 1, 2008, for the purposes of implementing a program for standards of performance for new stationary sources, except as follows:

4.1.a. 40 CFR §60.9 is amended to provide that information shall be available to the public in accordance with W.Va. Code §§22-5-1 et seq., 29B-1-1 et seq., and 45CSR31; and

4.1.b. Subparts B, C, Ca, Cb, Cc, Cd, Ce, Ea, Eb, Ec, WWW, AAAA, BBBB, CCCC, DDDD, EEEE, FFFF, and HHHH of 40 CFR Part 60 shall be excluded.

**§45-16-5. Secretary.**

5.1. Any and all references in 40 CFR Parts 60 and 65 to the "Administrator" are amended to be the "Secretary" except as follows:

5.1.a. where the federal regulations specifically provide that the Administrator shall retain authority and not transfer authority to the Secretary;

5.1.b. where provisions occur which refer to:

5.1.b.1. alternate means of emission limitations;

5.1.b.2. alternate control technologies;

5.1.b.3. innovative technology waivers;

5.1.b.4. alternate test methods;

5.1.b.5. alternate monitoring methods;

5.1.b.6. waivers/adjustments to recordkeeping and reporting;

5.1.b.7. emissions averaging;

5.1.b.8. applicability determinations; or

5.1.b.9. the authority to require testing under Section 114 of the Clean Air Act, as amended; or

5.1.c. where the context of the regulation clearly requires otherwise.

**§45-16-6. Permits.**

6.1. Nothing contained in this adoption by reference shall be construed or inferred to mean that permit requirements in accordance with applicable rules shall be in any way be limited or inapplicable.

**§45-16-7. Inconsistency Between Rules.**

7.1. In the event of any inconsistency between this rule and any other rule of the West Virginia Department of Environmental Protection, the inconsistency shall be resolved by the determination of the Secretary and the determination shall be based upon the application of the more stringent provision, term, condition, method or rule.

Federal Register

Tuesday,
June 24, 2008

Part IV

# Environmental Protection Agency

40 CFR Part 60
Standards of Performance for Petroleum Refineries; Final Rule

**ENVIRONMENTAL PROTECTION AGENCY**

**40 CFR Part 60**

**[EPA–HQ–OAR–2007–0011; FRL–8563–2]**

**RIN 2060–AN72**

## Standards of Performance for Petroleum Refineries

**AGENCY:** Environmental Protection Agency (EPA).

**ACTION:** Final rule.

**SUMMARY:** EPA is issuing final amendments to the current Standards of Performance for Petroleum Refineries. This action also promulgates separate standards of performance for new, modified, or reconstructed process units at petroleum refineries. The final standards for new process units include emissions limitations and work practice standards for fluid catalytic cracking units, fluid coking units, delayed coking units, fuel gas combustion devices, and sulfur recovery plants. These final standards reflect demonstrated improvements in emissions control technologies and work practices that have occurred since promulgation of the current standards.

**DATES:** These final rules are effective on June 24, 2008. The incorporation by reference of certain publications listed in the final rules is approved by the Director of the Federal Register as of June 24, 2008.

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

**SUPPLEMENTARY INFORMATION:**

### I. General Information

*A. Does this action apply to me?*

Categories and entities potentially regulated by 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 proposed 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 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 *http://www.epa.gov/ttn/oarpg.* The TTN provides information and technology exchange in various areas of air pollution control.

*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 August 25, 2008. 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 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.

*D. How is this document organized?*

The information presented in this preamble is organized as follows:

## II. Background Information

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

Section 111 of the CAA requires that NSPS reflect the application of the best system of emission reductions which (taking into consideration the cost of achieving such emission reductions, any non-air quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated. This level of control is commonly referred to as best demonstrated technology (BDT).

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. 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 (72 FR 27278, May 14, 2007). In response to several requests, we extended the 60-day comment period from July 13, 2007, to August 27, 2007 (72 FR 35375, June 28, 2007). We also issued a notice of data availability (NODA) (72 FR 69175, December 7, 2007) to notify the public that additional information had been added to the docket; the NODA also extended the public comment period on the proposed rule to January 7, 2008. We received a total of 38 comments from refineries, industry trade associations, and consultants; State and local environmental and public health agencies; environmental groups; and members of the public during the extended comment period, and 8 additional comments on the NODA. These final rules reflect our full consideration of all of the comments we received. Detailed responses to the comments not included in this preamble are contained in the Response to Comments document which is included in the docket for this rulemaking.

## III. Summary of the Final Rules and Changes Since Proposal

We are promulgating several amendments to provisions in the existing NSPS in 40 CFR part 60, subpart J. Many of these amendments are technical clarifications and corrections that are also included in the final standards in 40 CFR part 60, subpart Ja. For example, we are revising the definition of "fuel gas" to indicate that vapors collected and combusted to comply with certain wastewater and marine vessel loading provisions are not considered fuel gas. Consequently, these vapors are exempt from the sulfur dioxide ($SO_2$) treatment standard in 40 CFR 60.104(a)(1) and are not required to be monitored. We are also finalizing certain monitoring exemptions that we proposed for fuel gases that are identified as inherently low sulfur or demonstrated to contain a low sulfur content. See 40 CFR 60.105(a)(4)(iv). We are also revising the coke burn-off equation to account for oxygen ($O_2$)—enriched air streams. Other amendments include clarification of definitions and correction of grammatical and typographical errors.

The final standards in 40 CFR part 60, subpart Ja include emission limits for fluid catalytic cracking units (FCCU), fluid coking units (FCU), sulfur recovery plants (SRP), and fuel gas combustion devices. Subpart Ja also includes work practice standards for reducing emissions of volatile organic compounds (VOC) from flares, minimizing $SO_2$ emissions from fuel gas combustion devices and SRP, and for reducing emissions of VOC from delayed coking units. Only those affected facilities that commence construction, modification, or reconstruction after May 14, 2007 will be affected by the standards in subpart Ja. Units for which construction, modification, or reconstruction commenced on or before May 14, 2007 must continue to comply with the applicable standards under the current NSPS in 40 CFR part 60, subpart J, as amended.

### *A. What are the final amendments to the standards for petroleum refineries (40 CFR part 60, subpart J)?*

As proposed, we are amending the definition of "fuel gas" to specifically exclude vapors that are collected and combusted in an air pollution control device installed to comply with a specified wastewater or marine vessel loading emissions standard. The thermal combustion control devices themselves are still considered to be affected fuel gas combustion devices if they combust other gases that meet the definition of fuel gas, and all auxiliary fuel gas fired to these devices are subject to the fuel gas limit; however, continuous monitoring is not required for the vapors collected from wastewater or marine vessel loading operations that are being incinerated because these gases are not considered to be fuel gases under the definition of "fuel gas" in 40 CFR part 60, subpart J.

We are also finalizing exemptions for certain fuel gas streams from all continuous monitoring requirements. See 40 CFR 60.105(a)(4)(iv). Monitoring is not required for combustion in a flare of process upset gases or flaring of gases from relief valve leakage or emergency malfunctions since these streams are exempt from the standard under 40 CFR 60.104(a)(1). Additionally, monitoring is not required for inherently low sulfur fuel gas streams since the emissions generated by combusting such streams will necessarily be well below the standard. These streams include pilot gas flames, gas streams that meet commercial-grade product specifications with a sulfur content of 30 parts per million by volume (ppmv) or less, fuel gases produced by process

units that are intolerant to sulfur contamination, and fuel gas streams that an owner or operator can demonstrate are inherently low-sulfur. Owners and operators are required to document the exemption for which each fuel gas stream applies and ensure that the stream remains qualified for that exemption.

For accuracy in the calculation of the coke burn-off rate, we are revising the coke burn-off rate equation in 40 CFR 60.106(b)(3) to be consistent with the equation in 40 CFR 63.1564(b)(4)(i) of the National Emission Standards for Hazardous Air Pollutants for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units (40 CFR part 63, subpart UUU). This revision adds a fourth term to the coke burn-off rate equation to account for the use of $O_2$-enriched air. Other revisions to the equation change the constant values and the units of the resulting coke burn-off rate from Megagrams per hour (Mg/hr) and tons per hour (tons/hr) to kilograms per hour (kg/hr) and pounds per hour (lb/hr).

We proposed to amend the definition of "Claus sulfur recovery plant" in 40 CFR 60.101(i) to clarify that the SRP may consist of multiple units and that primary sulfur pits are considered part of the Claus SRP consistent with the Agency's current position. Commenters expressed concern that change to a 40 CFR part 60, subpart J definition that could lead to retroactive non-compliance. We disagree with those concerns as we believe the definition as currently written provides for such coverage. Nonetheless, we are not amending this definition in the final amendments for subpart J and will continue to address individual applicability issues under our applicability determination procedures. Similarly, we proposed revisions to the subpart J definitions of "oxidation control system" and "reduction control system" in 40 CFR 60.101(j) and 40 CFR 60.101(k), respectively, to clarify that these systems were intended to recycle the sulfur back to the Claus SRP. The proposed amendments needlessly limit the types of tail gas treatment systems that can be used; therefore, we are not amending these definitions in the final amendments for subpart J.

The final amendments also include technical corrections to fix references and other miscellaneous errors in 40 CFR part 60, subpart J. Table 1 of this preamble describes the miscellaneous technical corrections not previously described in this preamble that are included in the amendments to subpart J.

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

| Section | Technical correction and reason |
|---|---|
| 60.100 | Replace instances of "construction or modification" with "construction, reconstruction, or modification." |
| 60.100(a) | Replace "except Claus plants of 20 long tons per day (LTD) or less" with "except Claus plants with a design capacity for sulfur feed of 20 long tons per day (LTD) or less" to clarify that the size cutoff is based upon design capacity and sulfur content in the inlet stream rather than the amount of sulfur produced. |
| 60.100(b) | Insert ending date for applicability of 40 CFR part 60, subpart J (one date for flares and another date for all other affected facilities); sources beginning construction, reconstruction, or modification after this date will be subject to 40 CFR part 60, subpart Ja. |
| 60.102(b) | Replace "g/MJ" with "grams per Gigajoule (g/GJ)" to correct units. |
| 60.104(b)(1) | Replace "sulfur dioxide" with "$SO_2$" and replace "50 ppm by volume (vppm)" with "50 ppm by volume (ppmv)" for consistency in unit and acronym definition. |
| 60.104(b)(2) | Add "to reduce $SO_2$ emissions" to the end of the phrase "Without the use of an add-on control device" at the beginning of the paragraph to clarify the type of control device to which this paragraph refers; replace "sulfur dioxide" with "$SO_2$" for consistency in acronym definition. |
| 60.105(a)(3) | Add "either" before "an instrument for continuously monitoring" and replace "except where an $H_2S$ monitor is installed under paragraph (a)(4)" with "or monitoring as provided in paragraph (a)(4)" to more accurately refer to the requirements of § 60.105(a)(4) and clarify that there is a choice of monitoring requirements. |
| 60.105(a)(3)(iv) | Replace "accurately represents the $S_2$ emissions" with "accurately represents the $SO_2$ emissions" to correct a typographical error. |
| 60.105(a)(4) | Replace "In place" with "Instead" at the beginning of this paragraph and add "for fuel gas combustion devices subject to § 60.104(a)(1)" after "paragraph (a)(3) of this section" to clarify that there is a choice of monitoring requirements. |
| 60.105(a)(8) | Replace "seeks to comply with § 60.104(b)(1)" with "seeks to comply specifically with the 90-percent reduction option under § 60.104(b)(1)" to clearly identify the emission limit option to which the monitoring requirement in this paragraph refers. |
| 60.105(a)(8)(i) | Change "shall be set 125 percent" to "shall be set at 125 percent" to correct a grammatical error; replace "sulfur dioxide" with "$SO_2$" for consistency in acronym definition. |
| 60.106(e)(2) | Replace the incorrect reference to 40 CFR 60.105(a)(1) with a correct reference to 40 CFR 60.104(a)(1); add "The method ANSI/ASME PTC 19.10–1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 6 of Appendix A–4 to part 60." after the first sentence of this paragraph to include a voluntary consensus method. |
| 60.107(c)(1)(i) | Replace both occurrences of "50 vppm" with "50 ppmv" for consistency in unit definition. |
| 60.107(f) | Redesignate current 40 CFR 60.107(e) as 40 CFR 60.107(f) to allow space for a new paragraph (e). |
| 60.107(g) | Redesignate current 40 CFR 60.107(f) as 40 CFR 60.107(g) to allow space for a new paragraph (e). |
| 60.108(e) | Replace the incorrect reference to 40 CFR 60.107(e) with a correct reference to 40 CFR 60.107(f). |

*B. What are the final requirements for new fluid catalytic cracking units and new fluid coking units (40 CFR part 60, subpart Ja)?*

The final standards for new FCCU include emission limits for particulate matter (PM), $SO_2$, nitrogen oxides ($NO_X$), and carbon monoxide (CO). The final standards include no universal opacity limit because the opacity limit in 40 CFR part 60, subpart J is intended to ensure compliance with the PM limit. 40 CFR part 60, subpart Ja requires that sources use direct PM monitoring, bag leak detection systems, or parameter monitoring (along with annual emission tests) to ensure compliance with the PM limit. A provision for a site-specific opacity operating limit is provided for units that meet the PM emission limits using a cyclone.

For PM emissions from new FCCU and new FCU, we proposed a PM limit of 0.5 pounds (lb)/1,000 lb coke burnoff in the regenerator or (if a PM continuous emission monitoring system (CEMS) is

used), 0.020 grains per dry standard cubic feet (gr/dscf) corrected to 0 percent excess air. We have revised the final PM standards to establish separate limits for modified or reconstructed FCCU (1 lb/1,000 lb coke burn or 0.040 gr/dscf corrected to 0 percent excess air) and newly constructed FCCU (0.5 lb/1,000 lb coke burn or 0.020 gr/dscf corrected to 0 percent excess air). The final PM limit for new, modified, or reconstructed FCU is 1 lb/1,000 lb coke burn or 0.040 gr/dscf corrected to 0 percent excess air.

Initial compliance with the PM emission limits for FCCU and FCU is determined using EPA Method 5, 5B or 5F (40 CFR part 60, appendix A–3) instead of being restricted to only EPA Method 5 as previously proposed. Procedures for computing the PM emission rate using the total PM concentration, effluent gas flow rate, and coke burn-off rate are the same as in 40 CFR part 60, subpart J, as amended. To demonstrate ongoing compliance, an owner or operator must monitor PM emission control device operating parameters and conduct annual PM performance tests, use a PM CEMS, or operate bag leak detection systems and conduct annual PM performance tests. A new alternative allows refineries with wet scrubbers as PM control devices to use the approved alternative in 40 CFR 63.1573(a) for determining exhaust gas flow rate instead of a continuous parameter monitoring system (CPMS). An alternative to the requirements for monitoring the pressure drop from wet scrubbers that are equipped with jet ejectors or atomizing spray nozzles is to conduct a daily check of the air or water pressure to the nozzles and record the results of each inspection. The final rule also includes procedures for establishing an alternative opacity operating limit for refiners that use continuous opacity monitoring systems (COMS); this alternative is allowed only for units that choose to comply with the PM limit using cyclones. If operating parameters are used to demonstrate ongoing compliance, the owner or operator must monitor the same parameters during the initial performance test, and develop operating parameter limits for the applicable parameters. The operating limits must be based on the three-run average of the values for the applicable parameters measured over the three test runs. If ongoing compliance is demonstrated using a PM CEMS, the CEMS must meet the conditions in Performance Specification 11 (40 CFR part 60, appendix B) and the quality assurance (QA) procedures in Procedure 2, 40 CFR part 60, appendix F. The relative response audits must be conducted annually (in lieu of annual performance tests for units not employing a PM CEMS) and response correlation audits must be conducted once every 5 years.

For $NO_X$ emissions from the affected FCCU and FCU, we proposed a limit of 80 ppmv based on a 7-day rolling average (dry basis corrected to 0 percent excess air) and co-proposed having no limit for FCU. We are adopting the 80 ppmv $NO_X$ emission limits for FCCU and FCU as proposed. Initial compliance with the 80 ppmv emission limit is demonstrated by conducting a performance evaluation of the CEMS in accordance with Performance Specification 2 in 40 CFR part 60, appendix B, with Method 7 (40 CFR part 60, appendix A–4) as the reference method. Ongoing compliance with these emission limits is determined using the CEMS to measure $NO_X$ emissions as discharged to the atmosphere, averaged over 7-day periods.

No changes have been made to the proposed $SO_2$ emission limits for affected FCCU and FCU. The final $SO_2$ emission limits are to maintain $SO_2$ emissions to the atmosphere less than or equal to 50 ppmv on a 7-day rolling average basis, and less than or equal to 25 ppmv on a 365-day rolling average basis (both limits corrected to 0 percent moisture and 0 percent excess air). Initial compliance with the final $SO_2$ emission limits are demonstrated by conducting a performance evaluation of the $SO_2$ CEMS in accordance with Performance Specification 2 (40 CFR part 60, Appendix B) with Method 6, 6A, or 6C (40 CFR part 60, Appendix A–4) as the reference method. Ongoing compliance with both $SO_2$ emission limits is determined using the CEMS to measure $SO_2$ emissions as discharged to the atmosphere, averaged over the 7-day and 365-day averaging periods.

No changes have been made since proposal to the CO limits. The final CO emission limit for the affected FCCU and FCU is 500 ppmv (1-hour average, dry at 0 percent excess air). Initial compliance with this emission limit is demonstrated by conducting a performance evaluation for the CEMS in accordance with Performance Specification 4 (40 CFR part 60, appendix B) with Method 10 or 10A (40 CFR part 60, Appendix A–4) as the reference method. For Method 10 (40 CFR part 60, Appendix A–4), the integrated sampling technique is to be used. Ongoing compliance with this emission limit is determined on an hourly basis using the CEMS to measure CO emissions as discharged to the atmosphere. An exemption from monitoring may be requested for an FCCU or FCU if the owner or operator can demonstrate that "average CO emissions" are less than 50 ppmv (dry basis). As proposed, units that are exempted from the CO monitoring requirements must comply with control device operating parameter limits.

*C. What are the final requirements for new sulfur recovery plants (40 CFR part 60, subpart Ja)?*

For new, modified, and reconstructed SRP with a capacity greater than 20 long tons per day (LTD) (large SRP), we proposed a limit of 250 ppmv total sulfur (combined $SO_2$ and reduced sulfur compounds) as $SO_2$ (dry basis at 0 percent excess air determined on a 12-hour rolling average basis). The refinery could comply with the limit for each process train or release point or with a flow rate weighted average of 250 ppmv for all release points. For affected SRP with a capacity less than 20 LTD (small SRP), we proposed a mass emissions limit for total sulfur equal to 1 weight percent or less of sulfur recovered (determined hourly on a 12-hour rolling average basis).

In this final rule, we are adopting the current limits in subpart J (which include separate emission limits for oxidative and reductive systems) for affected large SRP. For these affected SRP, the final limits for SRP having an oxidation control system or a reduction control system followed by incineration is 250 ppmv (dry basis) of $SO_2$ at zero percent excess air. For an affected SRP with a reduction control system not followed by incineration, the final limit is 300 ppmv of reduced sulfur compounds and 10 ppmv of hydrogen sulfide ($H_2S$), each calculated as ppm $SO_2$ by volume (dry basis) at zero percent excess air. If the SRP consists of multiple process trains or release points, the refinery can comply with the limit for each process train or release point or with a flow rate weighted average of 250 ppmv for all release points. A new alternative allows refineries to use a correlation to calculate their effective emission limit for Claus SRP that use oxygen enrichment in the Claus burner. For a small affected SRP, the sulfur recovery efficiency standard is based on a sulfur recovery efficiency of 99 percent. However, due to the difficulties associated with on-going monitoring of SRP recovery efficiency, in this final rule, we are promulgating concentration limits that correlate with a sulfur recovery efficiency of 99 percent. For a Claus unit with an oxidative control system or any small SRP followed by an incinerator the emission limit is 2,500

ppmv (dry basis) of $SO_2$ at zero percent excess air. For all other small SRP, the emission limit is 3,000 ppmv reduced sulfur compound and 100 ppmv $H_2S$, each calculated as ppm $SO_2$ by volume (dry basis) at zero percent excess air. A similar correlation is provided for small Claus SRP that use oxygen enrichment, similar to that provided for large SRP. The standards for small SRP apply to all release points from the SRP combined (note that secondary sulfur storage units are not considered part of the SRP). We are not promulgating the $H_2S$ limit of 10 ppmv (dry basis, at 0 percent excess air determined on a 12-hour rolling average basis) or related operating limits that were included in § 60.102a(e) and (f) of the proposed rule.

Initial compliance with the emission limit for large SRP is demonstrated by conducting a performance evaluation for the $SO_2$ CEMS in accordance with either Performance Specification 2 (40 CFR part 60, Appendix B) for SRP with oxidation control systems or reduction control systems followed by incineration, or Performance Specification 5 (40 CFR part 60, Appendix B) for SRP with reduction control systems not followed by incineration. The owner or operator must operate and maintain oxygen monitors according to Performance Specification 3 (40 CFR part 60, Appendix B).

Ongoing compliance with the $SO_2$ limits for large SRP is determined using an $SO_2$ CEMS (for oxidative or reductive systems followed by incineration) or a CEMS that uses an air or $O_2$ dilution and oxidation system to convert the reduced sulfur to $SO_2$ and then measures the total resultant $SO_2$ concentration (for reductive systems not followed by incineration). An $O_2$ monitor is also required for converting the measured combined $SO_2$ concentration to the concentration at 0 percent $O_2$.

Initial and ongoing compliance requirements for small SRP are the same as for large SRP.

*D. What are the final requirements for new fuel gas combustion devices (40 CFR part 60, subpart Ja)?*

In the subpart Ja proposal, we divided fuel gas combustion devices into two separate affected sources: "process heaters" and "other fuel gas combustion devices." In response to comments, we have eliminated the proposed definition of "other fuel gas combustion devices" and revised the standards to either refer to fuel gas combustion devices, which include process heaters, or to refer specifically to process heaters. This revision makes the definition of "fuel gas combustion devices" consistent with subpart J. Based on public comments, we have also added a definition of "flare" as a subcategory of fuel gas combustion devices. The owner or operator of an affected flare must comply with the fuel gas combustion device requirements as well as specific provisions for flares as described in section III.E of this preamble.

We proposed a primary sulfur dioxide emission limit for fuel gas combustion devices of 20 ppmv or less $SO_2$ (dry at 0 percent excess air) on a 3-hour rolling average basis and 8 ppmv or less on a 365-day rolling average basis. We also proposed an alternative limit of 160 ppmv $H_2S$ or, in the case of coker-derived fuel gas, 160 ppmv total reduced sulfur (TRS), on a 3-hour rolling average basis and 60 ppmv or less on a 365-day rolling average basis. We are promulgating the 20 ppmv and 8 ppmv limits for $SO_2$ as proposed. We are also promulgating the alternative limit except that the limits are expressed and measured as $H_2S$ in all cases. The alternative $H_2S$ limit is 162 ppmv or less in the fuel gas on a 3-hour rolling average basis and 60 ppmv or less in the fuel gas on a 365-day rolling average basis. The alternative limit of 162 ppmv is based on standard conditions, which are defined in the NSPS General Provisions at 40 CFR 60.2 as being 68°F and 1 atmosphere. Using these as standard conditions, the subpart J emission limit is equivalent to 162 ppmv $H_2S$ rather than 160 ppmv. The final rule does not include an alternative TRS limit for $SO_2$.

Initial compliance with the 20 ppmv $SO_2$ limit or the 162 ppmv $H_2S$ concentration limits is demonstrated by conducting a performance evaluation for the CEMS. The performance evaluation for an $SO_2$ CEMS is conducted in accordance with Performance Specification 2 in 40 CFR part 60, Appendix B. The performance evaluation for an $H_2S$ CEMS is conducted in accordance with Performance Specification 7 in 40 CFR part 60, Appendix B. Ongoing compliance with the sulfur oxides emission limits is determined using the applicable CEMS to measure either $SO_2$ in the exhaust gas to the atmosphere or $H_2S$ in the fuel gas, averaged over the 3-hour and 365-day averaging periods.

Similar to clarifications for 40 CFR part 60, subpart J, the definition of "fuel gas" includes exemptions for vapors collected and combusted in an air pollution control device installed to comply with specified wastewater or marine vessel loading provisions. We are also streamlining the process for an owner or operator to demonstrate that a fuel gas stream not explicitly exempted from continuous monitoring is inherently low sulfur.

For new, modified, or reconstructed process heaters with a rated capacity greater than 20 million British thermal units per hour (MMBtu/hr), we proposed a $NO_X$ limit of 80 ppmv (dry basis, corrected to 0 percent excess air) on a 24-hour rolling average basis. The final $NO_X$ emission limit for affected process heaters is 40 ppmv on a 24-hour rolling average basis (dry at 0 percent excess air) for process heaters greater than 40 MMBtu/hr. For process heaters greater than 100 MMBtu/hr capacity, initial compliance with the 40 ppmv emission limit is demonstrated by conducting a performance evaluation of the CEMS in accordance with Performance Specification 2 in 40 CFR part 60, Appendix B. For process heaters between 40 MMBtu/hr and 100 MMBtu/hr capacity, initial compliance is demonstrated using EPA Method 7 (40 CFR part 60, Appendix A–4). For process heaters greater than 100 MMBtu/hr capacity, ongoing compliance with this emission limit is determined using the CEMS to measure $NO_X$ emissions as discharged to the atmosphere, averaged over 24-hour periods. For process heaters between 40 MMBtu/hr and 100 MMBtu/hr capacity, ongoing compliance with this emission limit is determined using biennial performance tests.

*E. What are the final work practice standards (40 CFR part 60, subpart Ja)?*

We proposed three work practice standards to reduce $SO_2$, VOC, and $NO_X$ emissions from flares and from startup, shutdown, and malfunction events and to reduce VOC and $SO_2$ emissions from delayed coking units. We also co-proposed to require only one of these work practice standards: the requirement to depressure delayed coking units. This proposed standard required new delayed coking units to depressure to 5 pounds per square inch gauge (psig) during reactor vessel depressuring and vent the exhaust gases to the fuel gas system.

We are promulgating a work practice standard for delayed coking units and modified requirements to reduce emissions from flares. The final work practice standard for delayed cokers requires affected delayed coking units to depressure to 5 pounds per square inch gauge (psig) during reactor vessel depressuring. We are requiring the exhaust gases to be vented to the fuel gas system as proposed or to a flare.

To reduce $SO_2$ emissions from the combustion of sour fuel gases, the final rule requires refineries to conduct a root

cause analysis of any emissions limit exceedance or process start-up, shutdown, upset, or malfunction that causes a discharge into the atmosphere, either directly or indirectly, from any fuel gas combustion device or sulfur recovery plant subject to the provisions of subpart Ja that exceeds 500 pounds per day (lb/day) of $SO_2$. Recordkeeping and reporting requirements apply in the event of such a discharge. Newly constructed and reconstructed flares must comply with these requirements immediately upon startup. Modified flares must comply no later than the first discharge that occurs after that flare has been an affected flare for 1 year.

In response to comments regarding the work practice standards for fuel gas producing units and associated difficulties with no routine flaring, we re-evaluated the work practice standards and have decided not to promulgate a work practice standard for fuel gas producing units. Rather, we have decided to define a flare as an affected facility and adopt regulations applicable to it. Therefore, we are not promulgating the proposed definition of "fuel gas producing unit" and the proposed requirement for "no routine flaring." Instead, we are promulgating the following requirements for flares that become affected facilities after June 24, 2008: (1) Flare fuel gas flow rate monitoring; (2) a flare fuel gas flow rate limit; and (3) a flare management plan. Affected flares cannot exceed a flow rate of 250,000 standard cubic feet per day (scfd) on a 30-day rolling average basis. In cases where the flow would exceed this value, the owner or operator would install a flare gas recovery system or implement other methods to reduce flaring from the affected flare. To demonstrate compliance with the flow rate limitations, flow rate monitors must be installed and operated. Newly constructed and reconstructed flares must comply with the flow rate limitations and the monitoring requirements immediately upon startup. Modified flares must comply with the flow rate limitations and the associated monitoring provisions no later than 1 year after the flare becomes an affected facility. A provision is provided for an exclusion from the flow limitation for times when the refinery can demonstrate that the refinery produces more fuel gas than it needs to fuel the refinery combustion devices (*i.e.*, it is fuel gas rich) or that the flow is due to an upset or malfunction, provided the refinery follows procedures outlined in the flare management plan. The flare management plan should address potential causes of fuel gas imbalances (*i.e.*, excess fuel gas) and records to be maintained to document these periods. As described in 40 CFR 60.103a(a), the flare management plan must include a diagram illustrating all connections to each affected flare, identification of the flow rate monitoring device and a detailed description of the manufacturer's specifications regarding quality assurance procedures, procedures to minimize flaring during planned start-up and shut down events, and procedures for implementing root cause analysis when daily flow to the flare exceeds 500,000 scfd. The root cause analysis procedures should address the evaluation of potential causes of upsets or malfunctions and records to be maintained to document the cause of the upset or malfunction. Newly constructed and reconstructed flares must comply with the flare management plan requirements immediately upon startup. Modified flares must comply with the flare management plan requirements no later than 1 year after the flare becomes an affected facility. Additionally, as described above, the owner or operator of a modified flare must conduct the first root cause analysis no later than the first discharge that occurs after that flare has been an affected flare for 1 year. Excess emission events for the flow rate limit of 250,000 scfd and the result of root cause analysis must be reported in the semi-annual compliance reports.

Because affected flares are also affected fuel gas combustion devices, the root cause analysis for $SO_2$ emissions exceeding 500 lbs/day also applies to all affected flares. However, compliance with the 500 lb/day root cause analysis will also require continuous monitoring of total reduced sulfur of all gases flared. Although all fuel gas combustion devices are required to comply with continuous $H_2S$ monitoring of fuel gas, flares routinely accept gases from upsets, malfunctions and startup and shutdown events, and $H_2S$ or sulfur monitoring is not specifically required for these gases. In subpart Ja, we explicitly require TRS monitoring for flares that become affected facilities after June 24, 2008 to ensure that the 500 lb/day $SO_2$ trigger is accurately measured. The owner or operator of a modified flare must install and operate the TRS monitoring instrument no later than 1 year after the flare becomes an affected facility. The owner or operator of a newly constructed or reconstructed flare must install and operate the TRS monitoring instrument no later than start-up of the flare.

*F. What are the modification and reconstruction provisions?*

Existing affected facilities that commence modification or reconstruction after May 14, 2007, are subject to the final standards in 40 CFR part 60, subpart Ja. A modification is any physical or operational change to an existing affected facility which results in an increase in the emission rate to the atmosphere of any pollutant to which a standard applies (see 40 CFR 60.14). Changes to an existing affected facility that do not result in an increase in the emission rate, as well as certain changes that have been exempted under the General Provisions (see 40 CFR 60.14(e)), are not considered modifications.

The intermittent operation of a flare makes it difficult to use the criteria of 40 CFR 60.14 to determine when a flare is modified; therefore, we have specified in the final rule the criteria that define a modification to a flare. A flare is considered to be modified if: (1) Any piping from a refinery process unit or fuel gas system is newly connected to the flare or (2) the flare is physically altered to increase flow capacity. See section IV.I of this preamble for further explanation on the change in affected source from a fuel gas producing unit to the flare.

Petroleum refinery process units are subject to the final standards in 40 CFR part 60, subpart Ja if they meet the criteria under the reconstruction provisions, regardless of changes in emission rate. Reconstruction means the replacement of components of an existing facility 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 facility; and (2) it is technologically and economically feasible to meet the applicable standards (40 CFR 60.15).

## IV. Summary of Significant Comments and Responses

As previously noted, we received a total of 46 comments during the public comment periods associated with the proposed rule and NODA. These comments were received from refineries, industry trade associations, and consultants; State and local environmental and public health agencies; environmental groups; and members of the public. In response to these public comments, most of the cost and emission reduction impact estimates were recalculated, resulting in several changes to the final amendments and new standards. The major comments and our responses are

summarized in the following sections. A summary of the remainder of the comments received during the comment period and responses thereto can be found in the docket for the final amendments and new standards (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 costs and cost-effectiveness of the control options and re-evaluated our BDT determinations. In our BDT determinations, we took all relevant factors into account consistent with other Agency decisions. It is important to note that, due to the different health and welfare effects associated with different pollutants, the acceptable cost-effectiveness value of a control option is pollutant dependent. These pollutant-specific factors were considered along with other factors in our BDT determinations.

*A. PM Limits for Fluid Catalytic Cracking Units*

*Comment:* Several commenters opposed the proposed tightening of the FCCU PM standards relative to subpart J and the concurrent change in PM monitoring methods. Some commenters supported the co-proposal to keep the 1 lb/1,000 lb coke burn PM emission limit based on Method 5B and/or 5F; other commenters either did not oppose or supported the 0.5 lb/1,000 lb coke burn emission limit for new "grassroots" units, provided EPA demonstrates it is cost-effective and that the limit is based on EPA Method 5B or 5F (40 CFR part 60, Appendix A–3).

Commenters stated that EPA should only impose the more stringent emission limits on new construction because it is much more difficult and costly to meet the proposed emission limits for modified or reconstructed equipment. Commenters suggested that if EPA does include more stringent limits on modifications, it should exclude certain actions (like projects implemented to meet consent decree requirements) from the definition of a modification.

Several commenters suggested that the costs in Table 11 of the proposal preamble are significantly underestimated. Commenters contended that the single "model plant" approach used in EPA's cost analysis does not realistically consider important factors such as the inherent sulfur content of the feed, partial-burn versus full-burn regeneration, FCCU/regenerator size, and sources that are already well-controlled due to other regulations. Commenters asserted that the purchased equipment costs escalated from estimates that are 20 to 30 years old are underestimated. Several commenters provided estimates of costs and emission reductions for several actual projects, which they stated indicate that EPA's costs are significantly underestimated and that the proposed standards are much less cost-effective than presented by EPA.

A number of commenters asserted that the PM standards should be based on EPA Methods 5B or 5F (40 CFR part 60, Appendix A–3), and not on EPA Method 5 of Appendix A–3 to part 60. According to these commenters, the achievability of the proposed 0.5 lb/1,000 lb coke burn PM limit based on EPA Method 5 is questionable because there are inadequate data on FCCU using EPA Method 5, and controlling combined condensable and filterable PM to the 0.5 lb/1,000 lb coke burn level has not been demonstrated to be cost-effective.

On the other hand, several commenters stated that any PM limit must include condensable and filterable PM as condensable PM account for a large portion of refinery PM emissions and all condensable PM is PM that is less than 2.5 micrometers in diameter ($PM_{2.5}$), which has more adverse health impacts than larger particles; the commenters therefore agreed with the use of EPA Method 5 to determine filterable PM and requested that EPA consider Method 202 (40 CFR part 51, Appendix M) for condensable PM. Commenters also stated that the limits for PM and $SO_2$ in subpart Ja should apply to all new, reconstructed, and modified FCCU. One commenter recommended that a total PM limit (filterable and condensable) be set at 1 lb/1,000 coke burn; another stated that the total PM limit, including both filterable and condensable PM, should be 0.5 lb/1,000 lb coke burn, and EPA has not demonstrated that current BDT cannot achieve this limit. Finally, one commenter suggested that EPA should evaluate the cost of removing each pollutant (PM and $SO_2$) separately.

*Response:* In response to these comments, we have revised our analysis to consider each unique existing FCCU in the United States. By doing so, we fully account for plant size, partial-burn versus full-burn regeneration, existing control configuration, and specific consent decree requirements. (Details on the specific revisions to the analysis can be found in the docket.) With a revised analysis, we were able to more directly assess the impacts of process modifications or reconstruction of existing equipment. We also assessed the effects of PM and $SO_2$ standards separately in this analysis.

In our revised analysis, we considered three options for PM: (1) Maintain the existing subpart J standard of 1.0 lb/1,000 lb of coke burn-off (filterable PM as measured by Method 5B or 5F); (2) 0.5 lb/1,000 lb of coke burn-off (filterable PM as measured by Method 5B or 5F of Appendix A–3 to part 60); and (3) 0.5 lb/1,000 lb of coke burn-off (filterable PM as measured by Method 5 of Appendix A–3 to part 60). Similar to the analysis for the proposed standards, costs and emission reductions for each option were estimated as the increment between complying with subpart J and subpart Ja. We note that none of the available data suggest that a 0.5 lb/1,000 lb coke burn emission limit that includes both filterable and condensable PM as measured using EPA Method 202 is achievable in practice for the full range of facilities using BDT controls, so we disagree with the comments suggesting this level is appropriate to consider as an option for a total PM limit in this rulemaking.

Option 1 includes the same emissions and requirements for PM as the current 40 CFR part 60, subpart J, so it will achieve no additional emissions reductions. The PM limit in Option 2 is the same numerical limit that was proposed in subpart Ja, but the PM emissions are determined using Methods 5B and 5F (40 CFR part 60, Appendix A–3). These test methods are commonly used for PM tests of FCCU and are the methods that were used to generate a majority of the test data we reviewed. Option 3 is a limit of 0.5 lb/1,000 lb coke burn using Method 5 and is the performance level that was proposed for subpart Ja. The impacts of these three options for new FCCU are presented in Table 2 to this preamble; the impacts for modified and reconstructed FCCU are presented in Table 3 to this preamble.

TABLE 2.—NATIONAL FIFTH YEAR IMPACTS OF OPTIONS FOR PM LIMITS CONSIDERED FOR NEW FLUID CATALYTIC CRACKING UNITS SUBJECT TO 40 CFR PART 60, SUBPART JA[a]

| Option | Capital cost ($1,000) | Total annual cost ($1,000/yr) | Emission reduction (tons PM/yr) | Cost effectiveness ($/ton) | |
|---|---|---|---|---|---|
| | | | | Overall | Incremental |
| 2 | 3,600 | 1,100 | 240 | 5,600 | 5,600 |
| 3 | 7,100 | 1,700 | 300 | 6,700 | 11,000 |

[a] PM cost-effectiveness calculated for PM-fine; 83.3 percent of the PM is PM-fine.

TABLE 3.—NATIONAL FIFTH YEAR IMPACTS OF OPTIONS FOR PM LIMITS CONSIDERED FOR RECONSTRUCTED AND MODIFIED FLUID CATALYTIC CRACKING UNITS SUBJECT TO 40 CFR PART 60, SUBPART JA[a]

| Option | Capital cost ($1,000) | Total annual cost ($1,000/yr) | Emission reduction (tons PM/yr) | Cost effectiveness ($/ton) | |
|---|---|---|---|---|---|
| | | | | Overall | Incremental |
| 2 | 75,000 | 12,000 | 690 | 21,000 | 21,000 |
| 3 | 100,000 | 15,000 | 810 | 23,000 | 37,000 |

[a] PM cost-effectiveness calculated for PM-fine; 83.3 percent of the PM is PM-fine.

The available data and impacts for the options considered suggest that BDT for new FCCU is different than BDT for modified and reconstructed FCCU. For new FCCU, the costs for Option 2 are reasonable compared to the emission reduction achieved. The incremental cost between Option 2 and Option 3 of $11,000 per ton PM-fine would generally be considered reasonable, but there are uncertainties in the achievability of Option 3. The estimated PM emission reduction achieved by Option 3 compared to Option 2 equals the amount of sulfates and other condensable PM between 250 °F and 320 °F that would be measured by Method 5 but not Method 5B or 5F (40 CFR part 60, Appendix A–3). Additionally, available test data indicate that electrostatic precipitators (ESP) and wet scrubbers can reduce total filterable PM to 0.5 lb/1,000 lb of coke burn or less, as measured by Method 5-equivalent test methods. Although there were few test data points using Method 5-equivalent test methods, we concluded at proposal that both electrostatic precipitators and wet scrubbers can achieve this level of PM emissions. However, the data supporting Option 3 are not extensive, and it is unclear at this time whether a limit of 0.5 kg/Mg of coke burn as measured by Method 5 (40 CFR part 60, Appendix A–3) could be met by all configurations of FCCU. In addition, while the Agency supports reducing condensable PM emissions, the amount of condensable PM captured by Method 5 is small relative to methods that specifically target condensable PM, such as Method 202 (40 CFR part 51, Appendix M). We prefer to develop a single performance standard that considers all condensable PM rather than implementing phased standards targeting different fractions of condensable PM. Such an approach would be costly and inefficient. Therefore, we conclude that Option 2, control of PM emissions (as measured by Methods 5B and 5F of Appendix A–3 to part 60) to 0.5 lb/1,000 lb of coke burn or less, is BDT for newly constructed FCCU. This option achieves PM emission reductions of 240 tons per year (tons/yr) from a baseline of 910 tons/yr at a cost of $5,600 per ton of PM.

For modified and reconstructed FCCU, Option 1 is the baseline level of control established by the existing requirements of subpart J. It will achieve no additional cost or emission reduction. The overall costs and the incremental costs for Options 2 and 3 are reasonable compared to the PM emission reduction; however, as with new FCCU, the performance of Option 3 has not been demonstrated, so it is rejected. Most of the existing FCCU that could become subject to subpart Ja through modification or reconstruction are either already subject to subpart J or are covered by the consent decrees. The consent decrees are generally based on the existing subpart J. Industry has made significant investments in complying with these subpart J requirements which may be abandoned if they become subject to subpart Ja. In addition, the additional costs could create a disincentive to modernize FCCU to make them more energy efficient or to produce more refined products. For these reasons, we reject Option 2 for modified or reconstructed FCCU and conclude that control of PM emissions (as measured by Methods 5B and 5F of Appendix A–3 to part 60) is 1.0 lb/1,000 lb of coke burn or less is BDT for reconstructed and modified FCCU.

*B. $SO_2$ Limits for Fluid Catalytic Cracking Units*

*Comment:* Several commenters supported the co-proposal for modified and reconstructed FCCU to meet subpart J and not the 25 ppmv 365-day rolling average limit for $SO_2$. Commenters provided data to suggest that the retrofits of existing sources are not cost effective, particularly if catalyst additives cannot be used. The current subpart J includes three compliance options: (1) If using an add-on control device, reduce $SO_2$ emissions by at least 90 percent or to less than 50 ppmv; (2) if not using an add-on control device, limit sulfur oxides emissions (calculated as $SO_2$) to no more than 9.8 kg/Mg of coke burn-off; or (3) process in the fluid catalytic cracking unit fresh feed that has a total sulfur content no greater than 0.30 percent by weight. Several commenters objected to the elimination of the additional compliance options in the existing subpart J for subpart Ja because: (1) There are no data to show that the $SO_2$ limits proposed in subpart Ja are BDT for all FCCU regenerator configurations; (2) the three options are already established as BDT and, therefore, the CAA requires that EPA make them available; and (3) the substantial cost and other burdens for a reconstructed or modified FCCU already complying with one of the alternative options in subpart J to change to daily monitoring by Method 8 (40 CFR part 60, Appendix A–4) or to install CEMS were not addressed in the proposal.

One commenter supported the proposed $SO_2$ limit under Ja for new "grassroots" FCCU if the standard is demonstrated to be cost-effective.

*Response:* As acknowledged in the previous response on PM standards for FCCU, we completely revised our impacts analysis to evaluate $SO_2$ standards for every existing FCCU that may become subject to subpart Ja through modification or reconstruction. We did not have access to the inherent sulfur content of the feed for each FCCU so $SO_2$ emissions are still estimated using average emission factors relevant to the type of control device used for FCCU not subject to consent decree requirements. Nonetheless, we significantly revised the impact analysis to fully account for FCCU-specific throughput, existing controls, and consent decree requirements. (Details on the specific revisions to the analysis can be found in Docket ID No. EPA–HQ–OAR–2007–0011.) We evaluated two options: (1) Current subpart J, including all three compliance options; and (2) 50 ppmv $SO_2$ on a 7-day average and 25 ppmv on a 365-day average. Data are not available on which to base a more stringent control level.

Option 1 includes the same emissions and requirements as the current 40 CFR part 60, subpart J, so it will achieve no additional emissions reductions. Based on information provided by vendors and data submitted by petroleum refiners, Option 2 can be met with catalyst additives or a wet scrubber. Of 38 FCCU currently subject to a 50/25 ppmv $SO_2$ limit through consent decrees, 26 used wet scrubbers and 12 used catalyst additives or other (unspecified) techniques. Given the number of FCCU currently meeting the 50/25 ppmv $SO_2$ emission limit, we conclude that this limit is technically feasible.

The data in the record suggest that all systems with wet scrubbers can meet the 50/25 ppmv $SO_2$ emission limit with no additional cost. Further, based on information from the consent decrees, we believe that the owner or operator of an existing FCCU that does not already have a wet scrubber and is modified or reconstructed such that it becomes subject to subpart Ja can use catalyst additives to meet the 50/25 ppmv $SO_2$ emission limit. Therefore, the cost of Option 2 is calculated using catalyst additives as the method facilities choose for meeting the standard. We reject the idea that the 90 percent control efficiency, the 9.8 kg/Mg coke burn-off limit, or the 0.3 weight percent sulfur content alternatives are equivalent to the 50/25 ppmv $SO_2$ emission limit. Based on the original background document for the subpart J standards, these alternatives are expected to have outlet $SO_2$ concentrations of 200 to 400 ppmv. In reality the currently used wet scrubbers and catalyst additives achieve much higher $SO_2$ removal efficiencies and much lower outlet $SO_2$ concentrations. The impacts of these options are presented in Table 4 of this preamble.

TABLE 4.—NATIONAL FIFTH YEAR IMPACTS OF OPTIONS FOR $SO_2$ LIMITS CONSIDERED FOR NEW, RECONSTRUCTED, AND MODIFIED FLUID CATALYTIC CRACKING UNITS SUBJECT TO 40 CFR PART 60, SUBPART JA

| Option | Capital cost ($1,000) | Total annual cost ($1,000/yr) | Emission reduction (tons $SO_2$/yr) | Cost effectiveness ($/ton) | |
|---|---|---|---|---|---|
| | | | | Overall | Incremental |
| 2 | 0 | 3,000 | 4,400 | 700 | 700 |

Based on the data we reviewed to select the options and the estimated impacts of those options, we conclude that Option 2, control of $SO_2$ emissions to 25 ppmv or less averaged over 365 days and 50 ppmv or less averaged over 7 days, is technically feasible and cost-effective for new, reconstructed, and modified fluid catalytic cracking units. This option has no capital cost and achieves $SO_2$ emission reductions of 4,400 tons/yr from a baseline of 5,900 tons/yr at a cost of $700 per ton of $SO_2$. Therefore, we conclude that control of $SO_2$ emissions to 25 ppmv or less averaged over 365 days and 50 ppmv or less averaged over 7 days is BDT for new, reconstructed, or modified fluid catalytic cracking units.

*C. $NO_X$ Limit for Fluid Catalytic Cracking Units*

*Comment:* Several commenters stated that they would support a $NO_X$ limit of 80 ppmv for new sources only, provided a corrected impact analysis considers the different characteristics of FCCU and demonstrates that the $NO_X$ limit for new sources is truly cost-effective. Commenters supported the co-proposal for modified and reconstructed FCCU to meet subpart J and not be subject to a $NO_X$ emission limit. A few commenters provided cost data showing the cost of $NO_X$ controls is high for modified and reconstructed units due to the high cost and space needed for add-on controls. The commenters also stated that a large number of existing FCCU in the U.S. are covered by consent decrees, so significant $NO_X$ reductions have already been (or will soon be) achieved, and an additional incremental reduction to 20 or 40 ppmv over a 365-day average are not widely demonstrated and would not be cost-effective.

One commenter stated that selective noncatalytic reduction (SNCR), selective catalytic reduction (SCR), and catalyst additives have not been demonstrated over significant periods of operational life. Commenters also cited environmental side-effects, such as the generation of ammonia compounds that contribute to condensable PM emissions, as a reason not to require these types of controls. Commenters also asserted that technologies like flue gas recirculation or advanced burner design are typically only cost-effective for new units and may be technically infeasible for existing FCCU.

One commenter suggested that if a limit is necessary for modified or reconstructed FCCU, recent catalyst additive trials support an emission limit of approximately 150 ppmv on a 7-day rolling average; this limit would only be achievable if a 24-hour CO averaging time was provided since lowering $NO_X$ tends to increase CO emissions in FCCU. The commenter noted that this limit is equivalent to the 0.15 pounds per million British thermal units (lb/MMBtu) standard for reconstructed and modified heaters and boilers in NSPS subpart Db.

Other commenters supported the inclusion of a $NO_X$ limit for FCCU and opposed the co-proposal of no $NO_X$ standard for modified and reconstructed FCCU. These commenters also recommended more stringent $NO_X$ limits for FCCU and stated that 80 ppmv does not represent an adequate level of control given the evolution of emerging technologies. In addition, a BDT of 80 ppmv on 7-day rolling average does not look "toward what may be fairly projected for the regulated future" as required by Portland Cement I (486 F. 2d 375 at 384 (D.C. Cir. 1973)) and other court decisions. The commenters disagreed with the feasibility and cost analyses for modified and reconstructed FCCU and stated that FCCU under a consent decree are achieving lower levels than the 80 ppmv proposed by EPA. Given the significant hazards to

human health and the environment posed by $NO_X$ emissions, the commenters recommended limits of 20 ppmv over a 365-day rolling average and 40 ppmv over a 7-day rolling average for all FCCU. The commenters noted that these limits have been successfully achieved under consent decrees and they are technically feasible on new units at reasonable costs without additional controls.

*Response:* As shown by the disparate comments received, many commenters suggest lower $NO_X$ emission limits are achievable, while other commenters do not believe the proposed $NO_X$ emission limits are cost-effective. While we do acknowledge that lower $NO_X$ emission limits are technically achievable, the incremental cost of achieving these lower limits was high when we evaluated options for the proposed standards. Therefore, we concluded at proposal that 20 or 40 ppmv $NO_X$ limits were not BDT. In our BDT assessment, we evaluated the various methods to meet alternative $NO_X$ limits as BDT rather than identifying one technology. One of the reasons for this is that each technology has its own advantages and limitations. While non-platinum oxidation promoters and advanced oxidation controls do not achieve the same reduction in $NO_X$ emissions as add-on control devices such as SCR, they do so without any significant secondary impacts. The added $NO_X$ reduction of SCR and SNCR must be balanced with these secondary impacts. Part of the basis for selecting control methods to achieve an 80 ppmv $NO_X$ emission limit as BDT included both cost and secondary impacts. This approach is necessary when conducting our BDT analysis, thus ensuring the best overall environmental benefit from the subpart Ja standards.

To ensure that we addressed the commenters' concerns, we re-evaluated the impacts for FCCU $NO_X$ controls. We also collected additional data from continuous $NO_X$ monitoring systems for a variety of FCCU $NO_X$ control systems. These data suggest that as refiners gain more experience with the $NO_X$ control systems (including catalyst additive improvements), $NO_X$ control performance has improved over the past year or two. These data suggest that the achievable level for combustion controls and catalyst additives is 80 ppmv and the achievable level for add-on control systems is 20 ppmv. Therefore, we evaluated three outlet $NO_X$ emission level options as part of the BDT determination: (1) 150 ppmv; (2) 80 ppmv; and (3) 20 ppmv. Each $NO_X$ concentration is averaged over 7 days. To estimate impacts for Option 1, we estimated that some units have current $NO_X$ emissions below 150 ppmv, and all other units can meet this level with combustion controls such as limiting excess $O_2$ or using non-platinum catalyst combustion promoters and other $NO_X$-reducing catalyst additives in a complete combustion catalyst regenerator or a combination of $NO_X$-reducing combustion promoters and catalyst additives with low-$NO_X$ burners (LNB) in a CO boiler after a partial combustion catalyst regenerator. Data collected from FCCU complying with consent decrees show that Option 2 can also be met using combustion controls; therefore, we estimated impacts for Option 2 using a similar method as Option 1. The main difference is that a larger number of FCCU must use combustion controls to meet the emission limit (*i.e.*, the FCCU with current $NO_X$ emissions between 150 and 80 ppmv would not need controls under Option 1 but would need controls under Option 2). Option 3 is the level at which we expect all units to install more costly control technology such as LoTOx™ or SCR. The estimated fifth-year emission reductions and costs for each option for new FCCU are summarized in Table 5 to this preamble; the impacts for modified and reconstructed FCCU are summarized in Table 6 to this preamble.

TABLE 5.—NATIONAL FIFTH YEAR IMPACTS OF OPTIONS FOR $NO_X$ LIMITS CONSIDERED FOR NEW FLUID CATALYTIC CRACKING UNITS SUBJECT TO 40 CFR PART 60, SUBPART JA

| Option | Capital cost ($1,000) | Total annual cost ($1,000/yr) | Emission reduction (tons $NO_X$/yr) | Cost effectiveness ($/ton) | |
|---|---|---|---|---|---|
| | | | | Overall | Incremental |
| 1 | 860 | 320 | 370 | 880 | 880 |
| 2 | 1,200 | 640 | 860 | 750 | 650 |
| 3 | 12,000 | 3,600 | 1,400 | 2,600 | 5,800 |

TABLE 6.—NATIONAL FIFTH YEAR IMPACTS OF OPTIONS FOR $NO_X$ LIMITS CONSIDERED FOR MODIFIED AND RECONSTRUCTED FLUID CATALYTIC CRACKING UNITS SUBJECT TO 40 CFR PART 60, SUBPART JA

| Option | Capital cost ($1,000) | Total annual cost ($1,000/yr) | Emission reduction (tons $NO_X$/yr) | Cost-effectiveness ($/ton) | |
|---|---|---|---|---|---|
| | | | | Overall | Incremental |
| 1 | 2,800 | 1,000 | 860 | 1,200 | 1,200 |
| 2 | 3,700 | 1,600 | 1,800 | 920 | 660 |
| 3 | 45,000 | 11,000 | 3,200 | 3,600 | 6,800 |

Options 1 and 2 provide cost-effective $NO_X$ control with limited or no secondary impacts. The costs of Option 1 and Option 2 are commensurate with the emission reductions for new FCCU as well as modified and reconstructed FCCU. Option 3 would impose compliance costs that are not warranted for the emissions reductions that would be achieved, as shown by the incremental cost-effectiveness values of about $6,000 per ton of $NO_X$ emission reduction between Option 2 and Option 3.

In evaluating these options, we also considered the secondary impacts. In addition to the direct PM impacts of SNCR and SCR, SCR and LoTOx™ units require additional electrical consumption. The increased energy consumption for Option 3 is 40,000 MW-hr/yr for new, modified, and reconstructed units. We also evaluated the secondary PM, $SO_2$, and $NO_X$ emission impacts of the additional electrical consumption for Option 3. Based on the energy impacts, Option 3 will generate secondary emissions of PM, $SO_2$, and $NO_X$ of 6, 150, and 57 tons/yr, respectively.

Based on the impacts shown in Table 5 and Table 6, and taking secondary impacts into account, we conclude that BDT is Option 2, a $NO_X$ emission limit of 80 ppmv, for all affected FCCU. For new FCCU, this option achieves $NO_X$ emission reductions of 860 tons/yr from a baseline of 1,500 tons/yr at a cost of $750 per ton of $NO_X$. For modified and reconstructed FCCU, this option achieves $NO_X$ emission reductions of 1,800 tons/yr from a baseline of 3,600 tons/yr at a cost of $920 per ton of $NO_X$.

*D. PM and $SO_2$ Limits for Fluid Coking Units*

*Comment:* Several commenters stated that EPA's proposed standards for FCU under subpart Ja are inappropriate and not cost-effective. Commenters asserted that based on the significant differences between FCU and FCCU operations, a separate BDT determination is needed for FCCU and FCU. Commenters stated that an FCU has higher particulate loading; a heavier feedstock that typically contains a higher concentration of sulfur, increasing the $SO_2$ and sulfur trioxide ($SO_3$) emissions; and a wider range of feedstocks with considerable variability in the nitrogen content.

The commenters noted that the impacts analysis performed for the FCU has shortcomings similar to those in the impacts analysis for FCCU (*e.g.*, the analysis did not properly consider the additional costs and technical difficulties of meeting the proposed emission limits for modified or reconstructed sources, existing units are already controlled and thus the emission reductions have already been achieved). One commenter provided site-specific engineering cost estimates to indicate that the PM controls are much less cost-effective than EPA estimates. The commenter requested that EPA consider instances when wastewater limitations require regenerative wet scrubbers and amend the impact estimates accordingly. One commenter stated that a newly installed regenerative wet scrubber system on an existing FCU could not meet the proposed Ja PM standards.

*Response:* As described in the preamble to the proposed standards, the original analysis assumed that one of the larger existing FCU will become a modified or reconstructed source in the next 5 years. However, the two larger FCU in the U.S. are both subject to consent decrees: one has installed controls and the other is in the process of installing controls. The remaining two FCU are significantly smaller than the original model FCU; therefore, a new analysis was conducted using a smaller model FCU indicative of the size of the two remaining FCU that are not subject to consent decree requirements. In our new analysis, this FCU has approximately one-half the sulfur content as the larger FCU for which we have data, based on information received regarding the variability in sulfur content across different FCU in the public comments.

In addition to revising our impact analysis, we also collected additional source test data from the one FCU operating a newly installed wet scrubber system to better characterize the control system's performance. At proposal, we had one FCU source test from this source, which suggested that the FCU wet scrubber could meet a PM limit of 0.5 lb/1,000 coke burn. However, following proposal, we received an additional performance test for this same FCU wet scrubber with an emission rate between 0.5 and 1.0 lb/1,000 lb coke burn. There was no indication of unusual performance during either of these two tests, so we conclude that these tests demonstrate the variability of the emission source and control system. Based on the available data, therefore, we conclude that an appropriate PM performance level to consider for a BDT analysis is 1.0 lb/1,000 lb coke burn using EPA Method 5B (40 CFR part 60, Appendix A–3) for a FCU with a wet scrubber. We also conclude that the PM emission limit initially proposed for FCU had not been adequately demonstrated as an emission limit with which one must comply at all times.

Using our revised model FCU and based on the additional source test data, we re-evaluated BDT for PM and $SO_2$ emissions from FCU based on two options: (1) No new standards, or current subpart J; and (2) a PM limit of 1.0 lb/1,000 lb coke burn (as measured using Methods 5B and 5F of 40 CFR part 60, Appendix A–3), a short-term $SO_2$ limit of 50 ppmv averaged over 7 days, and a long-term $SO_2$ limit of 25 ppmv averaged over 365 days. Unlike the FCCU, catalyst additives cannot be used in a FCU to reduce $SO_2$, so a wet scrubber is the most likely technology (and the one demonstrated technology) that would be used to meet the PM and $SO_2$ limits of Option 2. Therefore, we estimated costs for an enhanced wet scrubber to meet both the PM and $SO_2$ limits. The resulting emission reductions and costs for both of the options are shown in Table 7 of this preamble.

TABLE 7.—NATIONAL FIFTH YEAR IMPACTS OF OPTIONS FOR PM AND $SO_2$ LIMITS CONSIDERED FOR FLUID COKING UNITS SUBJECT TO 40 CFR PART 60, SUBPART JA

| Option | Capital cost ($1,000) | Total annual cost ($1,000/yr) | Emission reduction (tons PM/yr) | Emission reduction (tons $SO_2$/yr) | Cost effectiveness ($/ton PM and $SO_2$) |
|---|---|---|---|---|---|
| 2 | 10,000 | 3,200 | 1,000 | 5,900 | 460 |
| 2a | 100,000 | 18,600 | 1,000 | 5,900 | 2,700 |

One commenter indicated that we should consider the costs of a regenerative wet scrubber. This type of system is not needed in most applications; however, in the event such a system were needed, we estimated the cost of a regenerative wet scrubber to meet Option 2. The results of this analysis are also provided in Table 7 as Option 2a. As presented in Table 7, even under the most conservative assumptions the costs associated with the PM and $SO_2$ emission reductions are reasonable.

Based on the available technology and the costs presented in Table 7 to this preamble, we conclude that BDT is Option 2, which requires technology that reduces PM emissions to 1.0 lb/1,000 of coke burn and reduces $SO_2$ emissions to 50 ppmv averaged over 7 days and 25 ppmv averaged over 365 days. This option achieves PM emission reductions of 1,000 tons/yr from a baseline of 1,100 tons/yr and $SO_2$ emission reductions of 5,900 tons/yr from a baseline of 6,100 tons/yr at a cost of $460 per ton of PM and $SO_2$ combined.

*E. $NO_X$ Limit for Fluid Coking Units*

*Comment:* A number of commenters opposed the co-proposal of no $NO_X$ standard for FCU, and some disagreed with EPA's 80 ppmv $NO_X$ limit for FCU. These commenters recommended limits

of 20 ppmv as a 365-day rolling average and 40 ppmv as a 7-day rolling average for FCU, as has been successfully achieved under consent decrees. The commenters noted that these limits are achievable on new units without additional controls.

One commenter supported the co-proposal that no new $NO_X$ standard be established for FCU.

*Response:* Similar to the revised analysis for PM and $SO_2$ impacts, we re-evaluated BDT for the FCU $NO_X$ controls for a smaller modified or reconstructed FCU. We evaluated three options: (1) No new standards, which is the current subpart J; (2) outlet $NO_X$ concentration of 80 ppmv; and (3) outlet $NO_X$ concentration of 20 ppmv. Similar to the analysis for FCCU $NO_X$ and depending on the baseline emissions for the FCU, we anticipate that Option 2 can be met using combustion controls and Option 3 will require add-on control technology. The results of this analysis are shown in Table 8 to this preamble.

TABLE 8.—NATIONAL FIFTH YEAR IMPACTS OF OPTIONS FOR $NO_X$ LIMITS CONSIDERED FOR FLUID COKING UNITS SUBJECT TO 40 CFR PART 60, SUBPART JA

| Option | Capital cost ($1,000) | Total annual cost ($1,000/yr) | Emission/ reduction (tons $NO_X$ /yr) | Cost-effectiveness ($/ton) | |
|---|---|---|---|---|---|
| | | | | Overall | Incremental |
| 2 | 3,700 | 850 | 660 | 1,300 | 1,300 |
| 3 | 6,000 | 1,300 | 750 | 1,700 | 5,000 |

The costs for Option 1 and Option 2 are commensurate with the emission reductions, but the incremental impacts for Option 3 are not reasonable, as shown in Table 8. Option 3 achieves an additional 90 tons per year $NO_X$ reduction, but the incremental costs between options 2 and 3 of achieving this reduction is $5,000 per ton of $NO_X$ removed. The cost of achieving this 12 percent additional emission reduction nearly triples the total annualized cost of operating the controls. As with FCCU, the add-on $NO_X$ controls for FCU have increased energy requirements and secondary air pollution impacts. Based on these projected impacts, we support our original determination that BDT is Option 2, or technology needed to meet an outlet $NO_X$ concentration of 80 ppmv or less. This option achieves $NO_X$ emission reductions of 660 tons/yr from a baseline of 800 tons/yr at a cost of $1,300 per ton of $NO_X$.

*F. $SO_2$ Limit for Small Sulfur Recovery Plants*

*Comment:* One commenter stated that no new requirements should be added for SRP less than 20 LTD (small SRP) because the controls are not cost-effective. The commenter provided data on tail gas treatment projects but noted that these costs are for large SRP, and controls for small SRP will be less cost-effective. Several commenters noted that if EPA does establish standards for small SRP, the monitoring and compliance evaluation methods for the 99 percent control standard are not clearly specified in the rule and could create difficulties in documenting compliance for small Claus plants. Therefore, the small SRP should be allowed to comply with the 250 ppmv $SO_2$ emission limit provided to large SRP. One commenter suggested that non-Claus units should be subject to a 95 percent recovery efficiency standard.

*Response:* To ensure that we addressed the commenters' concerns regarding cost-effectiveness, we re-evaluated the impacts for small SRP. We adjusted our cost estimates upward based on capital costs provided by industry representatives. We evaluated three $SO_2$ control options as part of the BDT determination for small SRP: (1) No new standards, or current subpart J; (2) 99 percent sulfur recovery; and (3) 99.9 percent sulfur recovery. As noted in the preamble to the proposed standards (section V.D), the 99 percent and 99.9 percent recovery levels are achievable for SRP of all sizes by various types of SRP or tail gas treatments.

The estimated fifth-year emission reductions and costs for new SRP are summarized in Table 9 to this preamble; the impacts for modified and reconstructed SRP are summarized in Table 10 to this preamble. These values reflect the impacts only for small SRP; there are no additional cost impacts for large Claus units because they would already have to comply with the existing standards in subpart J.

TABLE 9.—NATIONAL FIFTH YEAR IMPACTS OF OPTIONS FOR $SO_2$ LIMITS CONSIDERED FOR NEW SMALL SULFUR RECOVERY PLANTS SUBJECT TO 40 CFR PART 60, SUBPART JA

| Option | Capital cost ($1,000) | Total annual cost ($1,000/yr) | Emission reduction (tons $SO_2$/yr) | Cost-effectiveness ($/ton) | |
|---|---|---|---|---|---|
| | | | | Overall | Incremental |
| 2 | 130 | 63 | 42 | 1,500 | 1,500 |
| 3 | 590 | 230 | 52 | 4,500 | 18,000 |

TABLE 10.—NATIONAL FIFTH YEAR IMPACTS OF OPTIONS FOR $SO_2$ LIMITS CONSIDERED FOR MODIFIED AND RECONSTRUCTED SMALL SULFUR RECOVERY PLANTS SUBJECT TO 40 CFR PART 60, SUBPART JA

| Option | Capital cost ($1,000) | Total annual cost ($1,000/yr) | Emission reduction (tons $SO_2$/yr) | Cost-effectiveness ($/ton) | |
|---|---|---|---|---|---|
| | | | | Overall | Incremental |
| 2 | 1,600 | 670 | 380 | 1,800 | 1,800 |

TABLE 10.—NATIONAL FIFTH YEAR IMPACTS OF OPTIONS FOR $SO_2$ LIMITS CONSIDERED FOR MODIFIED AND RECONSTRUCTED SMALL SULFUR RECOVERY PLANTS SUBJECT TO 40 CFR PART 60, SUBPART JA—Continued

| Option | Capital cost ($1,000) | Total annual cost ($1,000/yr) | Emission reduction (tons $SO_2$/yr) | Cost-effectiveness ($/ton) | |
|---|---|---|---|---|---|
| | | | | Overall | Incremental |
| 3 | 7,800 | 2,600 | 470 | 5,700 | 23,000 |

The costs for Option 2 are reasonable considering the emission reductions achieved, but the incremental impacts shown in Table 9 and Table 10 for Option 3 are beyond the costs that the Agency believes are reasonable for these small units to achieve an additional 100 tons per year of $SO_2$ emission reductions. The additional equipment needed to achieve these reductions quadruples the capital costs. These smaller units would also generally be found at small refineries. Based on these projected impacts and available performance data, we support our original determination that BDT is Option 2, or 99 percent sulfur recovery. For new SRP, this option achieves $SO_2$ emission reductions of 42 tons/yr from a baseline of 150 tons/yr at a cost of $1,500 per ton of $SO_2$. For modified and reconstructed SRP, this option achieves $SO_2$ emission reductions of 380 tons/yr from a baseline of 1,400 tons/yr at a cost of $1,800 per ton of $SO_2$.

We note that we are also revising the format of the standard in response to public comments in terms of sulfur outlet concentrations. Based on the Option 2 BDT selection of a recovery efficiency of 99 percent, the emission limit for small SRP is either 2,500 ppmv $SO_2$ or 3,000 ppmv reduced sulfur compounds and 100 ppmv of $H_2S$, both of which are determined on a dry basis, corrected to 0 percent $O_2$.

*G. $NO_X$ Limit for Process Heaters*

Comment: Several commenters stated that the 80 ppmv $NO_X$ limit for process heaters is not stringent enough. Commenters stated that considering recent settlement negotiations and regulation development, $NO_X$ emissions reductions well below 80 ppmv can be achieved cost effectively. The commenters stated that $NO_X$ emissions of less than 40 ppmv at 0 percent $O_2$ are achievable with combustion modifications such as LNB, ultra low—$NO_X$ burners (ULNB), and flue gas recirculation technologies; post-combustion controls such as SCR, SNCR, and LoTOx™ achieve $NO_X$ reductions an order of magnitude below those from combustion modifications. The commenters noted that Bay Area Air Quality Management District (BAAQMD) Regulation 9, Rule 10, requires process heaters to meet a 0.033 lb/MMBtu $NO_X$ limit (roughly 32 ppmv $NO_X$ at 0 percent oxygen). One commenter stated that 30 ppmv has been demonstrated under consent decrees to be an achievable level and ample technology exists. The commenters also noted that 7 to 10 ppmv $NO_X$ limits (at 3 percent oxygen) have been achieved in practice. One commenter stated that NSPS subparts J and Ja should impose $NO_X$ emission limits on all fuel gas combustion devices that are at least as stringent as the most stringent consent decree. Some consent decrees require next generation ULNB designed to achieve $NO_X$ emissions rates of 0.012 to 0.020 lb/MMBtu (12 to 20 ppmv $NO_X$ at 0 percent oxygen). Commenters recommending more stringent requirements suggested limits ranging from 7 ppmv $NO_X$ (at 3 percent oxygen) to 30 ppmv for new process heaters fueled by refinery fuel gas.

Other commenters stated that alternative monitoring options should be provided to small fuel gas combustion devices due to the high costs of CEMS relative to the emissions from the small devices. One commenter suggested an exemption from the fuel gas monitoring requirements for process heaters less than 50 MMBtu/hr. Another commenter recommended an exemption from the fuel gas monitoring requirements for process heaters less than 40 MMBtu/hr as used by South Coast Air Quality Management District (SCAQMD).

*Response:* We revisited the BDT determination based on the public comments and revised the methodology used to calculate the cost and emission reduction impacts for the proposed standards. We evaluated three options as part of the BDT determination. Each option consists of a potential $NO_X$ emission limit and applicability based on process heater size. These differ slightly from the proposal options based o n commenter suggestions. Option 1 would limit $NO_X$ emissions to 80 ppmv or less for all process heaters with a capacity greater than 20 MMBtu/hr (the proposed standards). Option 2 would limit $NO_X$ emissions to 40 ppmv or less for all process heaters with a capacity greater than 40 MMBtu/hr. This option is similar to many consent decrees that set an emission limit of 0.040 lb/MMBtu (roughly 40 ppmv $NO_X$ at 0 percent oxygen) for process heaters greater than 40 MMBtu/hr. Option 3 would limit $NO_X$ emissions to 20 ppmv or less for all process heaters with a capacity greater than 40 MMBtu/hr. In each option, the $NO_X$ concentration is based on a 24-hour rolling average.

The estimated fifth-year emission reductions and costs for each option for new process heaters are summarized in Table 11 of this preamble; impacts for modified and reconstructed process heaters are summarized in Table 12 of this preamble. Similar to the proposal analysis, we considered LNB, ULNB, flue gas recirculation, SCR, SNCR, and LoTOx™ as feasible technologies. We believe that nearly all process heaters at refineries that will become subject to subpart Ja can meet Option 1 or Option 2 using combustion controls (LNB or ULNB). Most process heaters would need to use more efficient control technologies, such as LoTOx™ or SCR, to meet the $NO_X$ concentration limit in Option 3. Per commenters' request to focus on the larger units, Options 2 and 3 do not include process heaters between 20 MMBtu/hr and 40 MMBtu/hr. We evaluated the cost-effectiveness of $NO_X$ control options for these units to achieve the proposed standard of 80 ppmv. For these process heaters with smaller capacities we found the cost-effectiveness ranged from $3,500/ton to $4,200/ton of $NO_X$ reduced, which was determined not to be reasonable for these small heaters, which would primarily be located at small refineries.

TABLE 11.—NATIONAL FIFTH YEAR IMPACTS OF OPTIONS FOR $NO_X$ LIMITS CONSIDERED FOR NEW PROCESS HEATERS SUBJECT TO 40 CFR PART 60, SUBPART JA

| Option | Capital cost ($1,000) | Total annual cost ($1,000/yr) | Emission reduction (tons $NO_X$/yr) | Cost-effectiveness ($/ton) | |
|---|---|---|---|---|---|
| | | | | Overall | Incremental |
| 1 | 9,000 | 7,300 | 4,800 | 1,500 | 1,500 |
| 2 | 9,000 | 7,500 | 5,200 | 1,400 | 500 |
| 3 | 110,000 | 30,000 | 5,900 | 5,100 | 37,000 |

TABLE 12.—NATIONAL FIFTH YEAR IMPACTS OF OPTIONS FOR $NO_X$ LIMITS CONSIDERED FOR MODIFIED AND RECONSTRUCTED PROCESS HEATERS SUBJECT TO 40 CFR PART 60, SUBPART JA

| Option | Capital cost ($1,000) | Total annual cost ($1,000/yr) | Emission reduction (tons $NO_X$/yr) | Cost-effectiveness ($/ton) | |
|---|---|---|---|---|---|
| | | | | Overall | Incremental |
| 1 | 12,000 | 4,000 | 2,100 | 1,900 | 1,900 |
| 2 | 14,000 | 4,300 | 2,200 | 1,900 | 2,100 |
| 3 | 64,000 | 15,000 | 2,500 | 5,900 | 39,000 |

Based on the impacts in Table 11 and Table 12, the costs of Options 1 and 2 are reasonable compared to the emission reductions. The incremental cost between Options 2 and 3 of almost $40,000/ton of $NO_X$ is not commensurate with the additional 1,000 tons of emission reduction achieved for new and modified or reconstructed process heaters. Moreover, the capital costs of Option 3 are about $150 million greater than the capital costs for Option 2, which are only $23 million. Therefore, we conclude that BDT for process heaters greater than 40 MMBtu/hr is technology that achieves an outlet $NO_X$ concentration of 40 ppmv or less, or Option 2. For new process heaters, this option achieves $NO_X$ emission reductions of 5,200 tons/yr from a baseline of 7,500 tons/yr at a cost of $1,400 per ton of $NO_X$. For modified and reconstructed process heaters, this option achieves $NO_X$ emission reductions of 2,200 tons/yr from a baseline of 3,200 tons/yr at a cost of $1,900 per ton of $NO_X$. Although we agree that lower $NO_X$ concentrations are achievable, we determined that the incremental cost to achieve these lower $NO_X$ concentrations was not reasonable.

*H. Fuel Gas Combustion Devices*

*Comment:* Several commenters contended that the proposed standards for fuel gas combustion devices were not stringent enough; EPA should ensure that the best demonstrated emission control technologies are installed as the industry is modernized. Given the significant hazards to human health and the environment posed by $SO_2$ emissions, the commenters suggested that the 365-day average limits should be 40 ppmv TRS and 5 ppmv $SO_2$. The commenters also recommended that EPA tighten the 3-hour concentration limit to 100 ppmv TRS. On the other hand, another commenter contended that although amine treatment applications for product gases can achieve $H_2S$ concentrations of 1 to 5 ppmv, a tighter standard is not BDT for refinery fuel gas.

Several commenters objected to the addition of the 60 ppmv $H_2S$ and 8 ppmv $SO_2$ limits (365-day rolling average) in the proposed subpart Ja standards for fuel gas combustion devices because they are infeasible and/or not cost-effective. According to commenters, EPA erroneously assumed that the additional reductions could be achieved with existing equipment. Although this may be true in some cases, commenters asserted that some refineries would need to add additional amine adsorber/regenerator capacity and some may also need to add additional sulfur recovery capacity (*e.g.*, an additional Claus train and tail gas treatment unit). One commenter requested an exemption be provided for refineries that cannot meet the tighter long-term standard by simply increasing their amine circulation rates. One commenter stated that there will be little incremental environmental benefit from the long-term limit, and it unnecessarily penalizes refineries that designed their amine systems to treat to levels near the proposed annual standard. The commenters provided cost data for examples of projects requiring new amine adsorption units to show that the proposed standards are not cost-effective.

A number of commenters particularly opposed the proposed revision to include TRS limits for fuel gas produced from coking units or any fuel gas mixed with fuel gas produced from coking units. One commenter noted that some State and local agencies have specific TRS standards, but these requirements were not based on a BDT assessment. According to commenters, EPA has included no technical basis for the achievability of the TRS fuel gas standard or explanation of why control of TRS is limited to fuel gas generated by coking units. The commenters recommended that EPA postpone adoption of a TRS limit until it has gathered and evaluated adequate data to conclude that the limit is technically feasible and cost effective.

Commenters stated that EPA did not address the cost-effectiveness and non-air quality impacts of the TRS standards and did not define BDT for the removal of TRS. One commenter stated that without an established *de minimis* level, an entire fuel gas system could be subject to the TRS limits if any amount of coker gas enters the fuel gas system. Amine scrubbing systems are selective to $H_2S$ and are not suitable to other TRS compounds such as mercaptans, according to the commenters. Commenters stated that the non-$H_2S$ TRS compounds are not amenable to amine treating and there is no technology readily in-place at refineries for reducing non-$H_2S$ TRS compounds. Therefore, according to the commenters, removing these other TRS compounds would require significant capital outlay for new equipment, costs that were not considered in the impacts analysis.

One commenter provided an example of a treatment system installed to meet a facility-wide fuel gas total sulfur standard of 40 ppmv; the commenter estimated the capital cost of the entire system to be $150 million. The commenter also indicated that low-BTU gas from flexicoking units would need to be specially treated at a capital cost of $61 million to achieve a total sulfur content of less than 150 ppmv, and the treatment would increase energy consumption, resulting in increases in $NO_X$ and CO emissions. Another commenter provided an order-of-magnitude engineering estimate of $50 million to treat TRS down to 45 ppmv (long-term average). Based on one commenter's experience with a new fuel gas treating facility, non-acidic TRS cannot be treated down to the proposed levels utilizing Merox-amine treatment. A cost-effective solution could be natural gas blending at the affected combustion device; however, this option has the negative effect of reducing the production of refinery fuel gas and therefore reducing the refinery's capacity for making gasoline.

Several commenters stated that the original BDT determination was based on amine scrubbing of $H_2S$ and not on $SO_2$; the $SO_2$ standard was simply a compliance option that was calculated to be equivalent to the $H_2S$ concentration limit at 0 percent excess air. They also asserted that EPA cannot use the $SO_2$ option as a basis for the TRS standard because the $SO_2$ option is not BDT. On the other hand, one commenter requested that EPA clarify the fuel gas standards in subpart J to expressly indicate that the 20 ppmv $SO_2$ limit is a valid compliance option (instead of including it only in the monitoring section). According to the commenter, focus has been on $H_2S$ due to the structure of the requirements of subpart J and permits rarely require that combustion sources demonstrate compliance with the 20 ppmv $SO_2$ limit. The commenter stated that refiners clearly should be allowed to comply with the broader, more comprehensive $SO_2$ limit.

A few commenters noted that, as $H_2S$ is part of TRS, the TRS standard is even more stringent than the $H_2S$ standard. One commenter recommended that no change in the fuel gas standards be made or that the standards focus on $H_2S$ only with an alternative emission limit for $SO_2$. One commenter stated that EPA developed the 160 ppmv $H_2S$ standard to be more stringent than the 20 ppmv $SO_2$ standard specifically because $H_2S$ did not represent all of the sulfur in the fuel gas. Commenters stated that using an F-factor approach (Method 19, 40 CFR part 60, Appendix A–7), the TRS limit that is equivalent to the 20 ppmv $SO_2$ emission limit is 260 ppmv and the TRS limit that is equivalent to the 8 ppmv $SO_2$ emission limit is 104 ppmv.

*Response:* We initially concluded that fuel gas generated by the coking unit was mixed with other fuel gases that were mostly $H_2S$ and that increasing the amine circulation rate would result in additional $H_2S$ removal that could be used to meet the proposed standard. However, based on a review of the available data, non-$H_2S$ sulfur content in coker fuel gas may be 300 to 500 ppmv. At these levels, specific treatment to reduce these other sulfur compounds would be needed. As indicated by one commenter, a plant-wide total sulfur limit of 40 ppmv has been achieved in practice in at least one refinery using a treatment train consisting of a Merox system, sponge oil absorbers, MEA absorbers, and caustic wash towers. Therefore, total sulfur fuel gas treatment methods are demonstrated. We evaluated the cost of this treatment based on information provided in the public comments.

Based on the public comments and additional data, we revisited the BDT determination and assessed three options for increasing $SO_2$ control of fuel gas combustion devices: (1) 20 ppmv $SO_2$ or 162 ppmv $H_2S$ averaged over 3 hours; (2) Option 1 plus 8 ppmv $SO_2$ or 60 ppmv $H_2S$ averaged over 365 days; and (3) a compliance option of 162 ppmv TRS averaged over 3 hours and 60 ppmv TRS averaged over 365 days for fuel gas combustion devices combusting fuel gas generated by a coking unit and Option 2 for combustion devices combusting fuel gas not generated by a coking unit. Option 1 includes the same limits that are in subpart J, so there are no additional costs or emission reductions beyond those expected from the application of subpart J. To address the commenters' concerns that not all facilities have available amine capacity to ensure compliance with the new long-term limits, we revised our proposal analysis to include additional costs for the estimated 10 percent of the affected facilities that would increase their amine capacity to achieve Option 2. We estimated costs for a separate treatment train that can treat TRS for Option 3 because, based on the public comments received, we have concluded that amine treatment systems are not effective for non-$H_2S$ components of TRS. The estimated fifth-year impacts of each of these options for new fuel gas combustion devices are presented in Table 13 of this preamble; the impacts for modified and reconstructed fuel gas combustion devices are presented in Table 14 of this preamble.

TABLE 13.—NATIONAL FIFTH YEAR IMPACTS OF OPTIONS FOR $SO_2$ LIMITS CONSIDERED FOR NEW FUEL GAS COMBUSTION DEVICES SUBJECT TO 40 CFR PART 60, SUBPART JA

| Option | Capital cost ($1,000) | Total annual cost ($1,000/yr) | Emission reduction (tons $SO_2$/yr) | Cost-effectiveness ($/ton) | |
|---|---|---|---|---|---|
| | | | | Overall | Incremental |
| 2 | 1,200 | 720 | 510 | 1,400 | 1,400 |
| 3 | 100,000 | 13,000 | 770 | 17,000 | 47,000 |

TABLE 14.—NATIONAL FIFTH YEAR IMPACTS OF OPTIONS FOR $SO_2$ LIMITS CONSIDERED FOR MODIFIED AND RECONSTRUCTED FUEL GAS COMBUSTION DEVICES SUBJECT TO 40 CFR PART 60, SUBPART JA

| Option | Capital cost ($1,000) | Total annual cost ($1,000/yr) | Emission reduction (tons $SO_2$/yr) | Cost-effectiveness ($/ton) | |
|---|---|---|---|---|---|
| | | | | Overall | Incremental |
| 2 | 33,000 | 11,000 | 4,700 | 2,400 | 2,400 |
| 3 | 1,700,000 | 200,000 | 7,600 | 26,000 | 63,000 |

Overall costs for Options 1 and 2 are reasonable compared to the emission reduction achieved for new, modified and reconstructed fuel gas combustion devices. We further evaluated the incremental costs and reductions between the three options and found that they were reasonable for Options 1 and 2, while the incremental cost for Option 3 is not. While Option 3 provides significant additional $SO_2$ emission reductions, the additional capital cost of $1.7 billion is high and could pose a significant barrier to future refinery upgrades and expansions. Based on these impacts and consideration of current operating practices, we conclude that BDT is use of technology that reduces the emissions from affected fuel gas combustion devices to 20 ppmv $SO_2$ or 162 ppmv $H_2S$ averaged over 3 hours and 8 ppmv $SO_2$ or 60 ppmv $H_2S$ averaged over 365 days, or Option 2. For new fuel gas combustion devices, this option achieves $SO_2$ emission reductions of 510 tons/yr from a baseline of 1,000 tons/yr at a cost of $1,400 per ton of $SO_2$. For modified and reconstructed fuel gas combustion devices, this option achieves $SO_2$ emission reductions of 4,700 tons/yr from a baseline of 10,000 tons/yr at a cost of $2,400 per ton of $SO_2$.

We note that although we have determined that Option 3 is not BDT and we will not limit the amount of $SO_2$ emissions from combustion of sulfur compounds other than $H_2S$ in subpart Ja, we plan to continue to work with the industry to understand the magnitude of these $SO_2$ emissions and to identify technologies that can be cost effectively applied to reduce the emissions. We have learned through this process that the $SO_2$ emissions from combustion of TRS in coker gas are generally not reflected in emission inventories and we plan to explore this issue in greater detail in the future to determine where $SO_2$ emissions are underestimated and the best way to correct the inventories.

*Comment:* Several commenters stated that it is impossible for a refinery owner or operator to specify, acquire, install, and calibrate a continuous monitoring system within 15 days of a change that increases the $H_2S$ concentration such that an exempt stream is no longer exempt. One commenter suggested quarterly stain tube sampling for 1 year prior to revoking an exemption from monitoring to confirm the change is permanent. The commenter suggested that after 1 year of confirmation, an additional 12 months be provided to specify, acquire, install, and calibrate the continuous monitoring system. One commenter suggested 1 year be provided for installing a CEMS, while another commenter suggested 180 days be provided (with an allowance for an additional extension) for installing a CEMS, rather than the 15 days proposed.

*Response:* We believe that in most cases, the process change would be a deliberate, planned act and that the potential consequences of this deliberate change would be evaluated. That is, before the equipment is modified, the refinery owner or operator is expected to assess the impacts of this change on the exempted fuel gas stream. If the change is expected to increase the sulfur content of the fuel gas, than the owner or operator can plan to install the required CEMS when modifying the process. We recognize that some process changes may have unexpected consequences, and a modification that was not expected to increase the sulfur content of the fuel gas can result in an increase in sulfur content. In this case, it may be impossible to install the required CEMS within 15 days. However, quarterly sampling does not provide any basis by which the refinery owner or operator can demonstrate compliance with the $H_2S$ concentration standard. Instead, we have added provisions that require an owner or operator to install a CEMS as soon as practicable and no later than 180 days after a change that makes the stream no longer exempt. Between the process change and the time a CEMS is installed, the owner or operator must conduct daily stain tube sampling to demonstrate compliance with the $H_2S$ concentration standard. During this time, a single daily sample exceeding 162 ppmv must be reported as an exceedance of the 3-hour $H_2S$ concentration limit and a rolling 365-day average concentration must be determined. A daily average $H_2S$ concentration of 5 ppmv is to be used for the days prior to the process change for the previously exempt stream in calculating the rolling 365-day average concentration.

*I. Flaring of Refinery Fuel Gas*

*Comment:* Several commenters supported the proposed work practice standards to eliminate routine flaring and develop startup, shutdown, and malfunction (SSM) plans; the commenters opposed the co-proposal of no standards. One commenter supported the determination that elimination of routine flaring is BDT, citing reductions in hydrocarbon, $NO_X$, $SO_2$, and carbon dioxide ($CO_2$) emissions. One commenter stated that both subparts J and Ja should explicitly require that flaring be used only as a last resort in unusual circumstances, such as emergencies, and not on a routine basis. Commenters asserted that monitoring on an ongoing basis is needed to verify that no flaring of nonexempt gases occurs. Commenters stated that subpart Ja should also require refiners to install a flare gas recovery system, although such requirements should not preclude monitoring requirements. One commenter stated that the NSPS should require a SSM plan to eliminate venting or flaring during such planned start-up, shutdown, and maintenance activities and explicitly prohibit venting or flaring during these planned activities; proper operation and maintenance practices should completely eliminate the need to use flares during these activities. One commenter noted that those refineries that have evaluated their startup and shutdown procedures to reduce or eliminate direct venting or flaring during planned startup and shutdown events have demonstrated the best technology; therefore, their actions represent BDT and should be adopted in the NSPS. The commenters also supported conducting a root cause analysis (RCA) in the event of flaring and other venting releases of 500 lb/day $SO_2$.

A number of commenters generally supported the intent to reduce flaring and the idea of SSM plans to address flaring during planned startups and shutdowns (one commenter also included combustion of high sulfur-containing fuel gases during a malfunction), flare management plans, and RCA for flare events in excess of 500 lb/day. However, they opposed the work practice standard for elimination of routine flaring and the proposed creation of fuel gas producing units for subpart Ja. The commenters stated that the definition of "fuel gas producing unit" is overly broad, making it difficult to determine what constitutes a modification or reconstruction, and the proposed work practice standard for these units is infeasible, unnecessary, and not cost-effective. Facility operators and regulators would have difficulty discerning if a flaring event was caused by an affected fuel gas producing unit or a unit not subject to the standard. One commenter indicated that there is no *de minimis* level by which units that produce insignificant quantities of fuel gas can be excluded from the extensive work practice standards.

Commenters recommended that the affected source be the flare which is already subject to the standard as a fuel gas combustion device. The commenters suggested that for each affected flare, the facility would develop a written Flare Management Plan designed to minimize

flaring of fuel gas during all periods of operation. This plan, along with the RCA, would ensure that all flaring events with potential excess emissions will be minimized. One commenter noted that EPA could require a flare management plan for any flare tied to a fuel gas system that has an affected fuel gas combustion device as a better alternative to "fuel gas producing units." One commenter noted that an exemption from the notification requirements for modified or reconstructed units could be provided as an incentive for early adoption of the flare management plan; another commenter suggested that regulatory incentives such as exemptions from monitoring and developing flare management plans should be provided for facilities that have installed flare gas recovery systems. One commenter supported this type of requirement for flares currently subject to subpart J, assuming a minimum of 9 months is provided for plan development and implementation. On the other hand, one commenter noted that the definitions of the affected facility under subparts J and Ja are different and recommended that the distinction be made stronger so that it is clear that existing process unit facilities are "grandfathered" and exempt from the flaring minimization standards.

One commenter suggested that the work practices language should be clarified to indicate that routing offgas to the flare system would be acceptable if the system was equipped with a flare gas recovery system. The prohibition should be specific to the flare itself as some flare systems are equipped with recovery compressors, the use of which should be encouraged rather than discouraged.

Commenters stressed the need for flares as safety devices; any flare minimization program must not interfere with the ability of the refinery owner or operator to use flares for safety reasons. The commenters stated that "routine" flaring cannot be adequately defined in practice; therefore, restrictions on "routine" flaring will lead to unsafe operations in attempts to avoid enforcement actions. The commenters requested that EPA include language in the regulation, consistent with the preamble discussion, that: "Nothing in this rule should be construed to compromise refinery operations and practices with regard to safety."

One commenter indicated that the proposed work practice standards for "no routine flaring" interfere with flare minimization plans implemented in response to consent decrees. The proposed work practice standard could be interpreted as prohibiting flaring during start-up and shutdown, and EPA has not determined this to be BDT. The commenter stated that the BAAQMD analysis applies to eliminating flaring during normal operation [similar to proposed § 60.103a(b)], not during start-up and shutdown as in proposed § 60.103a(a). The commenter provided cost estimates for one refinery to install a recovery system to eliminate flaring during start-up and shutdowns; the costs ranged from $200,000 to $800,000 per ton of VOC reduced and higher for other criteria pollutants. Therefore, they contend § 60.103a(a) should clearly exclude start-up and shutdown gases.

A few commenters provided overall project costs for flare gas recovery projects indicating the annual costs are higher than those in the analysis supporting the proposed work practice. One commenter stated that EPA underestimated the cost of flare gas recovery systems and, given the uncertainty in emission reductions, contended that flare gas recovery systems for the no-flaring option are not cost-effective within the NSPS context. The commenter also stated that the regulation should include maintenance provisions for flare gas recovery systems (that allow flaring) during times of routine and non-routine maintenance, as no redundant capacity within the flare system exists.

A number of commenters provided an alternative to EPA's proposed work practice standards. The suggestions included a 500 lb/day $SO_2$ standard tied with a flare management plan as an alternative compliance option (to the $H_2S$ concentration limit) for flares. The commenters recommended that this alternative compliance option be provided in both subparts J and Ja and noted that it could be used as an incentive for the flare management plan to cover all flares. One commenter also noted that these requirements should be applicable to flares that receive process gas, fuel gas, or process upset gas; they should not be applicable to flares used solely as an air pollution control device, such as a flare used exclusively to control emissions from a gasoline loading rack. Another commenter clarified that if the refinery elects to comply with this alternative for any flare, all flares at the refinery would need a flare management plan. The commenter noted that EPA could choose to set the 500 lb/day $SO_2$ limit as a total for all flares for which the alternative compliance option is chosen (*i.e.*, if the alternative compliance option is selected for two flares at a refinery, the total emissions from both flares would be limited to 500 lb/day).

*Response:* Although commenters suggested that certain provisions be made applicable to facilities subject to subpart J, the following provisions are only applicable to facilities subject to subpart Ja as CAA section 111 provides that new requirements apply only to new sources. We considered these comments and agree that the standards are more straightforward when the affected facility is defined as the flare. Therefore, we have eliminated "fuel gas producing units" as an affected facility in this final rule, and we specifically define a flare as a subset of fuel gas combustion device, which is an affected facility in this final rule. A "flare" means "an open-flame fuel gas combustion device used for burning off unwanted gas or flammable gas and liquids. The flare includes the foundation, flare tip, structural support, burner, igniter, flare controls including air injection or steam injection systems, flame arrestors, knockout pots, piping and header systems."

There are three general work practice standards that were proposed for "fuel gas producing units," which may be summarized as follows: (1) The "no routine flaring" requirement; (2) flare minimization plan for start-up, shutdown, and malfunction events; and (3) a root-cause analysis for $SO_2$ releases exceeding 500 lb/day (which was proposed for all affected fuel gas producing units). The "no routine flaring" work practice was not intended to prohibit flaring during SSM events; the provisions were intended to apply only during normal operating conditions. We agree with the commenter that suggested that nothing in this rule should be construed to compromise refinery operations and practices with regard to safety. Additionally, as discussed in the preamble to the proposed rule, we specifically rejected a prohibition on flaring for planned start-up and shutdown events. We agree with the commenters that noted that numerous refineries have demonstrated that flare minimization during planned start-up and shutdown activities can greatly reduce flaring during these events. We do believe, however, that a complete elimination of flaring during these events is very site-specific and although it is reported to have been achieved at a limited number of refineries, we do not have information to suggest that it has been adequately demonstrated for universal application. As "no routine flaring" is difficult to define in practice, we have re-evaluated BDT using more specific options.

Option 1 is no additional standards for flares. In Option 2, any routine emissions event or any process start-up, shutdown, upset or malfunction that causes a discharge into the atmosphere more than 500 pounds per day of $SO_2$ (in excess of the allowable emission limit) from an affected fuel gas combustion device or sulfur recovery plant would require a root cause analysis to be performed. This approach is similar to what is included in most consent decrees. We are also including a requirement for continuous monitoring of TRS for all gases flared (including those from upsets, startups, shutdowns, and malfunction events), in order to accurately measure $SO_2$ emissions from affected flares.

Option 3 includes: (1) The $SO_2$ root cause analysis in Option 2; (2) a limit on the fuel gas flow rate to the flare of 250,000 scfd; and (3) a flare management plan for SSM events. The flow limit of 250,000 scfd is based on our cost analysis that indicates that for typical gas streams in quantities above this limit, the value of recovered fuel completely offsets the costs of installing and operating recovery systems. Many refineries have implemented flare gas recovery to reduce energy needs and save money. The flare management plan must: (1) Include a diagram illustrating all connections to each affected flare; (2) identify the flow rate monitoring device and a detailed description of manufacturer's specifications regarding quality assurance procedures; (3) include standard operating procedures for planned start-ups and shutdowns of refinery process units that vent to the flare (such as staging of process shutdowns) to minimize flaring during these events; (4) include procedures for a root cause analysis of any process upset or equipment malfunction that causes a discharge to the flare in excess of 500,000 scfd; and (5) include an evaluation of potential causes of fuel gas imbalances (*i.e.*, excess fuel gas), upsets or malfunctions and procedures to minimize their occurrence and records to be maintained to document periods of excess fuel gas. Excess emission events for the flow rate limit of 250,000 scfd and the result of root cause analysis must be reported in the semi-annual compliance reports.

Option 4 is identical to Option 3 except that flaring is limited to 50,000 scfd. This level is estimated to be a baseline level that accounts for the flow requirement needed to maintain safe operations of the flare (*i.e.*, flow of sweep gas and compressor cycle gas). For both Option 3 and Option 4, the limit on the flow rate does not apply during malfunctions and unplanned startups and shutdowns. The flow rate limits in Options 3 and 4 were developed to reduce VOC, $SO_2$, and $NO_X$ emissions; the limits are based on 30-day rolling average flow rate values.

It is anticipated that a flare gas recovery system will be used to comply with Options 3 and 4 when a flare is currently used on a continuous basis, and the recovered flare gas offsets natural gas purchases. The cost-effectiveness of the flare gas recovery system is primarily dependent on the quantity of gas that the system can recover. Many refineries have already implemented similar work practices through consent decrees and local rules (BAAQMD and SCAQMD), and these requirements have had a demonstrated reduction in flaring events. Flare gas recovery will reduce $SO_2$, $NO_X$, and VOC emissions. However, if a refinery produces more fuel gas than the refinery needs to power its equipment, there is no place the refinery can use the recovered fuel gas and there is no additional natural gas purchases to offset. In these cases, flare gas recovery is not considered technically feasible because the excess fuel gas will have to be flared. Therefore, we have included specific provision within the flare management plan to address instances of excess fuel gas. For periods when the refinery owner or operator can demonstrate, through records of natural gas purchases or other means as described in their flare management plan, that the refinery is fuel gas rich, compliance with the flow limit is demonstrated by implementing the procedures described in the flare management plan.

Impacts for each of the four options are based on estimates of current flaring quantities and include the root cause analysis, flare management plan, and flare gas recovery systems when needed. The impacts for each option for new flares are presented in Table 15 to this preamble; impacts for modified and reconstructed flares are presented in Table 16 to this preamble.

TABLE 15.—NATIONAL FIFTH YEAR IMPACTS OF OPTIONS FOR WORK PRACTICES CONSIDERED FOR NEW FLARING DEVICES SUBJECT TO 40 CFR PART 60, SUBPART JA

| Option | Capital cost ($1,000) | Total annual cost ($1,000/yr) | Emission reduction (tons $SO_2$/yr) | Emission reduction (tons $NO_X$/yr) | Emission reduction (tons VOC/yr) | Cost-effectiveness ($/ton) | |
|---|---|---|---|---|---|---|---|
| | | | | | | Overall | Incremental |
| 2 | 0 | 23 | 15 | 0 | 0 | 1,600 | 1,600 |
| 3 | 8,800 | (1,300) | 16 | 1 | 41 | (23,000) | (31,000) |
| 4 | 15,000 | (840) | 16 | 1 | 52 | (12,000) | 43,000 |

TABLE 16.—NATIONAL FIFTH YEAR IMPACTS OF OPTIONS FOR WORK PRACTICES CONSIDERED FOR MODIFIED AND RECONSTRUCTED FLARING DEVICES SUBJECT TO 40 CFR PART 60, SUBPART JA

| Option | Capital cost ($1,000) | Total annual cost ($1,000/yr) | Emission reduction (tons $SO_2$/yr) | Emission reduction (tons $NO_X$/yr) | Emission reduction (tons VOC/yr) | Cost-effectiveness ($/ton) | |
|---|---|---|---|---|---|---|---|
| | | | | | | Overall | Incremental |
| 2 | 0 | 92 | 59 | 0 | 0 | 1,600 | 1,600 |
| 3 | 35,000 | (5,300) | 64 | 4 | 165 | (23,000) | (31,000) |
| 4 | 59,000 | (3,300) | 66 | 6 | 207 | (12,000) | 43,000 |

Based on these impacts and consideration of technically feasible operating practices, we conclude that BDT is Option 3. Option 3 includes a set of work practice standards that requires root cause analysis for a discharge into the atmosphere in excess of 500 pounds per day of $SO_2$ (over the allowable emission limit) from a fuel gas combustion device or sulfur recovery plant or in excess of 500,000 scfd flow to a flare. It also includes a flare

management plan. Finally, fuel gas flow to the flare is limited to 250,000 scfd. To support implementation of these requirements, monitoring and reporting of the flow rate and sulfur content is required. For new flaring devices, this option achieves $SO_2$ emission reductions of 16 tons/yr from a baseline of 32 tons/yr, $NO_X$ emission reductions of 1 tons/yr from a baseline of 2 tons/yr, and VOC emission reductions of 41 tons/yr from a baseline of 67 tons/yr with a net fuel savings of $23,000 per ton of combined $SO_2$, $NO_X$, and VOC. For modified and reconstructed flaring devices, this option achieves $SO_2$ emission reductions of 64 tons/yr from a baseline of 129 tons/yr, $NO_X$ emission reductions of 4 tons/yr from a baseline of 7 tons/yr, and VOC emission reductions of 165 tons/yr from a baseline of 266 tons/yr with a net fuel savings of $23,000 per ton of combined $SO_2$, $NO_X$, and VOC.

The flare gas minimization requirements included in the final standards are important to reduce criteria pollutant emissions and conserve energy. However, we recognize that owners and operators also need to be able to make quick changes to existing process units or flare systems to avoid unsafe conditions. It could take an owner or operator more time to implement the flare requirements, especially flow monitoring and any physical changes needed to comply with the limit on flow to the flare, than it took to implement the change to the flare that caused it to be an affected facility. There is the potential for serious safety concerns if the owner or operator must wait until compliance has been achieved with all of the flare gas minimization requirements prior to venting explosive vapors to the flare or modifying the flare system, such as adding a knockout pot for safety reasons. Moreover, avoiding unsafe conditions by requiring immediate shutdown of all process units connected to the potentially affected flare while the owner or operator takes steps to comply with the final provisions specific to flare gas minimization results in additional emissions, significant costs, and large lost production of refined products. By providing 1 year for modified flares to comply with these flare gas minimization provisions, refinery owners and operators have sufficient time to coordinate the installation of the flow rate and sulfur content monitors, to take whatever steps necessary to meet the flow limitations, to develop and implement the flare management plan, and to make other modifications, if needed, regarding safety and maintenance considerations for other process equipment tied to the flare.

Considering the cost and the energy penalty from the reduction in refined products (*e.g.*, the need to shut down the refinery until the flare gas minimization requirements can be met) and emissions associated with the immediate application of these requirements of the rule to modified flares, we determined that BDT was to phase in the requirements. The owner or operator of a modified flare would have to comply with the applicable $H_2S$ limit immediately and would have 1 year to implement the flare gas minimization requirements. Therefore, the final standards specify that for modified flares, the $H_2S$ limits for fuel gas combustion units apply immediately and the flare gas minimization requirements apply no later than 1 year after the flare becomes an affected facility. For newly constructed and reconstructed flares, the $H_2S$ limits and all of the flare gas minimization requirements apply immediately upon start-up of the affected flare.

*Comment:* Several commenters requested clarification of how one would assess a flare "modification." Questions included: (1) How the emission basis of a flare should be calculated; (2) if the modification determination would be based on flare capacity or increase in discharge capability of units connected to the flare; (3) whether the modification determination would include all possible flaring events or just non-emergency flaring; (4) whether adding a new line to a flare is considered to increase the capacity of the flare and cause a modification; (5) whether flare tip replacements are considered routine maintenance instead of a modification of the flare, even if the new flare tip has a different geometry (*e.g.*, a larger diameter to reduce noise); and (6) how SSM streams are considered when calculating baseline emissions for a modification determination. The commenters also suggested that EPA should clarify whether and how the exemption in § 60.14(e)(2) applies to a flare, including how the production rate for a flare would be defined.

*Response:* Section 60.14(a) defines modification as follows: "Except as provided in paragraphs (e) and (f) of this section, any physical or operational change to an existing facility which results in an increase in the emission rate to the atmosphere of any pollutant to which a standard applies shall be considered a modification." Section 60.14(e) provides exclusions for maintenance activities, increased production rates, increased hours of operation, etc. However, except for the maintenance exclusion, the other exemptions are either not applicable or ambiguous when applied to a flare. More importantly, § 60.14(f) states that "Applicable provisions set forth under an applicable subpart of this part shall supersede any conflicting provisions of this section." Therefore, to eliminate ambiguity, we specifically define what constitutes a flare modification in subpart Ja.

A flare is considered to be modified in one of two ways. First, a flare is considered to be modified when any piping from a refinery process unit or fuel gas system is newly connected to the flare. This new piping could allow additional gas to be sent to the flare, consequently increasing emissions from the flare. Second, a flare is considered to be modified if that flare is physically altered to increase flow capacity.

While in most cases an affected facility must comply with the final standard if it commences construction, reconstruction or modification after the proposal date, section 111(a)(2) of the CAA also provides that in certain circumstances such a source only need comply with the standard if it commences construction after the final date. Given the number of changes between proposal and final, we have concluded that this is one of the rare cases in which the final, rather than proposal, date applies.

In this case, we are promulgating a newly defined affected facility, adding a new provision specifically defining what constitutes a modification of a flare, adding several new requirements, and adding a definition of a flare. All of these changes significantly alter what would be an affected facility and the obligations of the affected facility for purposes of reducing flaring. Furthermore, while some of the requirements that were proposed for the fuel gas producing unit were transferred to the flare as an affected source, the scope of these requirements changed significantly when they were applied to a flare rather than a fuel gas producing unit. Specifically, under the proposal, only the gas stream from the modified fuel gas producing unit was barred from routine flaring. Under the final rule, however all of the units connected to the flare are now addressed, not just the fuel gas producing unit that was new, modified, or reconstructed.

Accordingly, we are providing in the final standards that only those flares commencing construction, reconstruction, or modification after June 24, 2008 must meet the requirements in subpart Ja. Flares

commencing construction, reconstruction, or modification after June 11, 1973, and on or before June 24, 2008 must meet the requirements in subpart J regarding fuel gas combustion devices (*i.e.*, the $H_2S$ fuel gas limit).

*J. Delayed Coking Units*

*Comment:* Several commenters supported the proposal that requires delayed coking units to depressure the coke drums to the fuel gas system down to 5 psig. One commenter supported venting the delayed coker gas to a flare or to the atmosphere at pressures less than 5 psig; at pressures greater than 5 psig, the commenter suggested that the rule should only prohibit gases from being sent to a flare and allow any other disposition. That is, the commenter stated that EPA should not restrict the disposition of the coker depressurization gas to only the fuel gas system.

One commenter supported inclusion of a coke drum pressure limit above which the coke drum exhaust gases must be sent to a recovery system, disagreed that it is technically infeasible to divert emissions for recovery at pressures below 5 psig, and urged EPA to require venting until the pressure drops below 2 psig. The commenter recently issued a permit including the 2 psig level, and although the modification has not been completed, the commenter believes the requirement is technically feasible.

A number of commenters objected to the finding that BDT is to depressure delayed coking units to the fuel gas system down to 5 psig. Commenters provided examples of coking units whose current mode of operations (*e.g.*, set points or timed cycles) may divert to a flare or to the atmosphere at pressures of approximately 10 to 20 psig and that it would not be cost-effective to modify these units to comply with the proposed work practice standard. One commenter supported the premise that it is cost-effective for delayed coking discharge to be routed to fuel gas blowdown, but depressurization down to 5 psig may not be feasible with existing equipment; the commenter recommended that the work practice simply require a closed blow down system following procedures described in the facility's SSM plan. At a minimum, an alternative is needed for existing units that would require capital expenditure to meet the 5 psig proposal. One commenter stated that compressors cannot recover blowdown system gases at pressures below the fuel gas recovery compressor suction pressure. The minimum pressure at which a suction compressor can operate depends on the design of the coking unit and the blowdown management system. Because there is uncertainty surrounding the available emission information, the costs are not minimal in most cases, and the emissions are difficult to measure, the commenter stated that EPA cannot determine that controls on coker vents is BDT.

*Response:* Based on the public comments, we re-evaluated BDT for delayed coking units. We considered three options: (1) Depressurization down to 15 psig; (2) depressurization down to 5 psig; and (3) depressurization down to 2 psig. We estimated that the baseline is, on average, depressurization down to 15 psig and then venting to the atmosphere. Therefore, there are no impacts for Option 1. Impacts for Options 2 and 3 were estimated based on the baseline conditions, the size of typical coke drums, and cost information provided in public comments. We also collected emissions test data to support and verify the projected emissions and emission reductions. The impacts for each option for new delayed coking units are presented in Table 17 to this preamble; impacts for modified and reconstructed delayed coking units are presented in Table 18 to this preamble.

TABLE 17.—NATIONAL FIFTH YEAR IMPACTS OF OPTIONS FOR WORK PRACTICES CONSIDERED FOR NEW DELAYED COKING UNITS SUBJECT TO 40 CFR PART 60, SUBPART JA

| Option | Capital cost ($1,000) | Total annual cost ($1,000/yr) | Emission reduction (tons $SO_2$/yr) | Emission reduction (tons VOC/yr) | Cost-effectiveness ($/ton) | |
|---|---|---|---|---|---|---|
| | | | | | Overall | Incremental |
| 2 | 2,400 | 230 | 170 | 2 | 1,300 | 1,300 |
| 3 | 24,000 | 2,300 | 230 | 3 | 9,900 | 38,000 |

TABLE 18.—NATIONAL FIFTH YEAR IMPACTS OF OPTIONS FOR WORK PRACTICES CONSIDERED FOR MODIFIED AND RECONSTRUCTED DELAYED COKING UNITS SUBJECT TO 40 CFR PART 60, SUBPART JA

| Option | Capital cost ($1,000) | Total annual cost ($1,000/yr) | Emission reduction (tons $SO_2$/yr) | Emission reduction (tons VOC/yr) | Cost-effectiveness ($/ton) | |
|---|---|---|---|---|---|---|
| | | | | | Overall | Incremental |
| 2 | 14,000 | 1,400 | 260 | 4 | 5,100 | 5,100 |
| 3 | 54,000 | 5,100 | 340 | 5 | 15,000 | 47,000 |

Based on these impacts and consideration of technically feasible operating practices, we confirmed our conclusion at proposal that BDT is depressurization down to 5 psig, or Option 2. For new delayed coking units, this option achieves $SO_2$ emission reductions of 170 tons/yr from a baseline of 520 tons/yr and VOC emission reductions of 2 tons/yr from a baseline of 7 tons/yr at a cost of $1,300 per ton of combined $SO_2$ and VOC. For modified and reconstructed delayed coking units, this option achieves $SO_2$ emission reductions of 260 tons/yr from a baseline of 780 tons/yr and VOC emission reductions of 4 tons/yr from a baseline of 11 tons/yr at a cost of $5,100 per ton of combined $SO_2$ and VOC. Although Option 3 has been established in one refiner's permit, this level of depressurization has not been demonstrated in practice. Additionally, the difference in the quantity of gas released when the set point is 2 psig rather than 5 psig is relatively small, 80 tons of $SO_2$ and 4 tons of VOC, and the resulting incremental cost-effectiveness from Option 2 to Option 3 is about $40,000/ton, which is much greater. Therefore, Option 3, or depressurization down to 2 psig, is not BDT.

*K. Other Comments*

*Comment:* One commenter contested the criteria EPA used in its Regulatory Flexibility Act/Small Business Regulatory Enforcement Fairness Act (RFA/SBREFA) analysis for defining a

small refiner as one with no more than 1,500 employees or more than 125,000 barrels per day (BPD) average crude capacity and requested that EPA use what the commenter alleged is the commonly recognized definition in other EPA programs of no more than 1,500 employees or more than 155,000 BPD average crude capacity. The commenter noted that EPA did not make any effort in the Regulatory Impact Analysis or in the proposal preamble to support its selection or explain why it adopted this definition.

*Response:* Under the SBA regulations, a small refiner is defined as a refinery with no more than 1,500 employees. See Table in 13 CFR 121.201, NAICS code 324110. Additionally, for government procurement purposes only, footnote 4 to that Table further provides that a small refinery must meet a certain capacity threshold as follows: "For purposes of Government procurement, the petroleum refiner must be a concern that has no more than 1,500 employees nor more than 125,000 barrels per calendar day total Operable Atmospheric Crude Oil Distillation capacity." After reviewing our analysis, we realized that we inadvertently used the capacity limit to evaluate the impacts on small refiners; the definition that should have been used is 1,500 employees with no capacity limit. We have recalculated the economic impact on the small entities using the corrected definition of small refiner, and our conclusion that the rule will not have a significant economic impact on a substantial number of small entities has not changed. See section VI.C of this preamble and the Regulatory Impacts Analysis (RIA) in the docket for additional details.

The commenter is incorrect in asserting that EPA uses any other definition for small refiner than the SBA definition when conducting its RFA/SBREFA analysis in other rulemakings. EPA consistently uses the SBA definition of a small refiner for such purposes. However, in promulgating regulations, EPA may define a small refiner differently when deciding what standards and requirements apply to these facilities. For example, in the fuel standards promulgated by EPA (*e.g.*, Control of Air Pollution From New Motor Vehicles: Tier 2 Motor Vehicle Emissions Standards and Gasoline Sulfur Control Requirements (65 FR 6698)), EPA set different requirements for small refiners than for all other refiners, and the 155,000 BPD capacity cutoff cited by the commenter is one of the criteria used to define a small refiner in those standards. See 40 CFR 80.225. However, the RFA/SBREFA analysis conducted in that rulemaking regarding whether those rules had a significant economic impact on a substantial number of small entities was not conducted based on any capacity cutoff. See 65 FR 6817.

*Comment:* One commenter stated that EPA is required under section 111 of the CAA to promulgate NSPS for each of the pollutants emitted by the source category that cause or contribute significantly to air pollution which may reasonably be anticipated to endanger public health or welfare. The commenter stated that there is scientific consensus that greenhouse gases are a leading cause of global warming, and anthropogenic emissions of greenhouse gases (GHG) such as $CO_2$ and methane ($CH_4$) are increasing and driving the warming. Petroleum refineries are a significant source of fossil fuel $CO_2$ emissions because they consume large quantities of energy, and in fact, U.S. petroleum refineries consume over 3.2 percent of the total U.S. energy consumption. Petroleum refineries also emit $CH_4$ and are responsible for an additional 0.6 teragrams of $CO_2$ equivalence via $CH_4$ emissions. Therefore, the commenter believes that EPA must set NSPS for $CO_2$ and $CH_4$ because petroleum refineries' emissions of $CO_2$ and $CH_4$ cause and contribute significantly to air pollution which may reasonably be anticipated to endanger public health and welfare.

Two commenters cited the Supreme Court decision in *Massachusetts* v. *EPA*, where the Court found that carbon dioxide and other GHG fit into the statutory definition of "air pollutant" in the CAA. Commenter 0128 stated that in *Massachusetts* v. *EPA*, the Supreme Court rejected EPA's overly narrow interpretation that greenhouse gases do not fall under the definition. The Court also voided EPA's term "air pollution" and noted that because greenhouse gases both enter the ambient air and warm the atmosphere, they are unquestionably agents of air pollution.

Another commenter contended that while the decision in *Massachusetts* v. *EPA* states that GHG are "air pollutants" as that term is used in CAA section 111, section 111 does not require EPA to address all air pollutants in NSPS. Therefore, the Supreme Court's decision does not mean that EPA necessarily must regulate GHG through NSPS. Instead of beginning to address GHG in specific NSPS, the commenter stated that EPA should develop a comprehensive plan for addressing GHG that ensures that "any necessary reductions in GHG emissions are achieved in a consistent and equitable manner across all industry sectors." The commenter further stated that since the issue of GHG emissions was not raised in the proposal preamble for subparts J and Ja, it would be inappropriate for EPA to promulgate GHG standards in those subparts without first proposing the new standards.

*Response:* While section 111(b)(1)(B) of the CAA permits EPA, under appropriate circumstances, to add new standards of performance for additional pollutants concurrent with the 8-year review of existing standards, for the reasons set forth below, EPA declines to promulgate performance standards for GHG, including $CO_2$ and $CH_4$, from petroleum refineries as part of this 8-year review cycle.

Section 111(b)(1)(B) imposes two obligations upon EPA for a source category listed under section 111(b)(1)(A). First, within 1 year of listing a source category, section 111(b)(1)(B) requires the Administrator to "publish proposed regulations, establishing Federal standards of performance for new sources" within such category. After providing "interested persons an opportunity for written comment on such proposed regulations," EPA must then "promulgate, within one year after such publication, such standards" as the Administrator "deems appropriate." The Agency has always interpreted this initial requirement as providing the Administrator with significant flexibility in determining which pollutants are appropriate for regulation under section 111(b)(1)(B). See *National Lime Assoc.* v. *EPA*, 627 F.2d 416, 426 (DC Cir. 1980) (explaining reasons for not promulgating standards for $NO_x$, $SO_2$, and CO from lime plants); see also *National Assoc. of Clean Air Agencies* v. *EPA*, 489 F.3d 1221, 1228–1230 (DC Cir. 2007) (finding that the "deems appropriate" language in CAA section 231 provides a "delegation of authority" that is "both explicit and extraordinarily broad," giving EPA's regulation "controlling weight unless it is manifestly contrary to the statute").

Second, the statute requires that:

> "The Administrator shall, at least every 8 years, review and, if appropriate, revise such standards following the procedure required by this subsection for promulgation of such standards. Notwithstanding the requirements of the previous sentence, 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 such standard."

Nothing in the 8-year review provision mandates that EPA include a new standard of performance for an air pollutant not already covered by the

standard of performance under review. Instead, the 8-year review provision can be reasonably understood as requiring "review" of only "such standards" [1] as were previously promulgated. As there would be no standard to review for an air pollutant not already subject to the standard, there would be no requirement for promulgating a new standard of performance since the "review" requirement in section 111(b)(1)(B) cannot be transformed into a "promulgation" requirement.[2] Moreover, as noted above, even if the 8-year review provision were a "promulgation" requirement, such a requirement still would not mandate that EPA set performance standards for all air pollutants emitted from the source category. In the 1990 CAA Amendments, Congress amended the definition of "standard of performance" to be "a standard for emissions of air pollutants," specifically deleting the word "any" from the phrase "any air pollutant" that was contained in the 1977 definition. This amendment restored the definition to the 1970 version. This deliberate change demonstrates that Congress was aware that the 1970 definition did not require EPA to cover all air pollutants emitted from a source category. Additionally, by reinstating the 1970 definition through the 1990 CAA amendments, Congress was also indicating its understanding that EPA is not required to regulate all air pollutants emitted from a source under section 111.

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, EPA is promulgating a new standard of performance for $NO_X$ emissions from certain affected facilities at refineries in this rulemaking. However, contrary to commenters' assertions,[3] these actions were discretionary; EPA may, but is not required to, promulgate new standards of performance concurrent with its 8-year review. While it may often be appropriate for EPA to exercise its discretion by promulgating new standards of performance concurrent with an 8-year review, because it is in the process of gathering information and reviewing controls for an industry, for the reasons set forth above, EPA reasonably interprets section 111(b)(1)(B) to not mandate such a result.

In this instance, it is reasonable for EPA not to promulgate performance standards for GHG emissions as part of this 8-year review cycle. We believe that the nature of GHG emissions renders them readily distinguishable from other air pollutants for which we have previously promulgated new performance standards concurrent with an 8-year review of the existing standards. Indeed, GHG emissions present issues that we have never had to address in the context of even an initial NSPS rulemaking for a source category. These differences warrant proceeding initially through a more deliberate process, *i.e.*, the announced advanced notice of proposed rulemaking (ANPR), than in this source category-specific rulemaking. While commenters correctly note that we have previously exercised our discretion to promulgate new performance standards concurrent with an 8-year review, and indeed are doing so here with respect to $NO_X$, the exercise of that discretion had limited impact as those air pollutants were either already regulated elsewhere under the Act or were emitted by a sufficiently limited subset of source categories. Here, promulgating new performance standards for these air pollutants in this one source category could potentially mandate regulation for numerous other source categories under several other parts of the Act. Similarly, our initial decision to regulate non-National Ambient Air Quality Standards (NAAQS) air pollutants in an NSPS has generally raised issues limited to the source category before us. For example, with the exception of landfill related air pollutants,[4] our decisions to regulate non-NAAQS air pollutants were reached at a time prior to the enactment of the statutory Prevention of Significant Deterioration (PSD) program and accordingly did not implicate the many complexities that we are struggling with today and which we intend to address in the ANPR discussed below. *See* 45 FR 52,676, 52,708–10 (Aug. 7, 1980).

In contrast to those circumstances, the regulation of GHG emissions raises numerous issues that are not well suited to initial resolution in a rulemaking directed at an individual source category. To that end, as Administrator Johnson announced on March 27, 2008, in letters to Senator Barbara Boxer and Representative John Dingell, it is his intent to issue an ANPR in the very near future that explores and seeks public comment on the many complex interconnections between the relevant sections of the Clean Air Act, including section 111, and lays the foundation for a comprehensive path forward with respect to regulation of all GHG.

We have previously noted that at this stage it is most appropriate to address these complexities in an ANPR addressing a variety of interconnected statutory provisions. In his April 10, 2008, testimony before the Subcommittee on Energy and Air Quality, Committee on Energy and Commerce, U.S. House of Representatives, Robert J. Meyers, Principal Deputy Assistant Administrator of the Office of Air and Radiation, further elaborated on the reasons for and anticipated content of an ANPR and discussed some of these complexities. For example, he noted the potential complexities resulting from implementation of the PSD preconstruction review permitting program:

> For PSD purposes, major stationary sources are those with the potential to emit 100 tons per year of a regulated air pollutant in the case of certain statutorily-listed source categories, and 250 tons per year in the case of all other source categories. New large schools, nursing homes, and hospitals could be considered a "major source" under this section of the Clean Air Act. For modifications, only those that increase

[1] Commenters assert that "the term 'such standards' incorporates the inclusive 'any' air pollutant language in the definition of a 'standard of performance'" and therefore contemplates new standards of performance during the 8-year review. See Comments, pg. 3. However, the word "any" does not appear in the definition of "standard of performance" in the manner quoted by commenters. See CAA section 111(a)(1).

[2] Commenters assert that EPA must develop performance standards during the 8-year review "for *any* air pollutant" emitted by a source "provided that EPA finds those emissions cause or contribute to air pollution" that may endanger public health or welfare. See Comments, pg. 2. To the extent any such finding were required, EPA notes that no such finding has been made regarding GHG emitted from refineries. Indeed, 111(b)(1)(A), which contains the only endangerment finding requirement in section 111, gives the Administrator significant discretion on the timing of endangerment findings after the initial set of source category listings ("from time to time thereafter shall revise"). Nothing in the statute ties the endangerment and 8-year review requirements. Hence, commenters' own arguments lack merit and EPA is under no obligation for promulgating GHG performance standards for refineries.

[3] Commenters again predicate their assertions on a prerequisite endangerment finding. See Comments, pg. 4. As explained in footnote 2, EPA has made no such finding and therefore under petitioners' interpretation is under no obligation to promulgate GHG performance standards for this source category.

[4] Because of the unique nature of landfill related air pollutants the Agency determined it was appropriate to define the air pollutants at issue as emissions from landfills and thus limited the potential implications for other programs. *See* 56 FR 24468, 24470 (May 30, 1991). In other words, only landfills emit these particular air pollutants; thus, it was appropriate that only this source category was subject to the PSD program for this air pollutant.

emissions above a tonnage threshold established by EPA for each regulated pollutant through rulemaking triggers PSD. Until EPA establishes this so-called "significance" level, however, any increase in a regulated pollutant at a major stationary source undergoing a modification would trigger PSD permitting.

As noted previously, PSD sources are required to install best available control technology (BACT). BACT must be at least as stringent as any applicable NSPS, and is to reflect the maximum degree of emissions reduction achievable for such a facility, taking into account energy, environment and economic impacts and other costs.

Controlling GHG emissions under any section of the Clean Air Act could significantly increase the number of stationary sources subject to PSD permitting.

Because $CO_2$ is typically emitted in larger quantities than criteria and other traditional air pollutants from combustion sources, facilities not previously subject to Clean Air Act permitting—such as large commercial and residential buildings heated by natural gas boilers—could qualify as major stationary sources for PSD purposes. In addition, some small industrial sources not now covered by PSD could be expected to become subject to PSD due to their GHG emissions.

Currently, our best estimate of the potential impact of including GHG in the PSD program is that the number of PSD permits issued annually nationwide could rise by an order of magnitude above the current 200–300 a year. Such estimates are subject to significant uncertainty. At present, we do not have comprehensive information on GHG emissions from the many categories of stationary sources of such emissions; instead we have relied on available information and general engineering estimates.

Such a broadening of the PSD program could pose significant implementation issues for covered facilities (particularly newly covered facilities) and permitting agencies. EPA is examining the scope of these potential difficulties and whether, for GHG, the program could be limited to larger sources, at least temporarily, in view of the very substantial increase in administrative burden that might otherwise occur. However, at present it is unclear as to whether EPA has the legal discretion to exempt sources above the statutory thresholds. In addition, EPA is exploring concepts for streamlining implementation of the PSD program for smaller sources, such as guidance on general permits or source definitions for BACT determinations and model permits for use by permitting agencies. EPA will address permitting issues in greater detail in the planned ANPR.

Given the complexity of PSD issues arising from regulation of GHG emissions, among other complex issues of regulating a pollutant—particularly a pollutant global in nature—for the first time under the CAA, it is reasonable for the Agency to proceed first by evaluating these issues, and other potential complexities, in the previously announced ANPR rather than by taking action to promulgate performance standards for GHG emissions in this rulemaking.

In addition to the reasons set forth above, it is appropriate for EPA to decline to promulgate performance standards for GHG emissions concurrent with this 8-year review as section 111(b)(1)(B) does not require that the Agency revise the standards when essential information becomes available too late in the review period. The 8-year review provision itself conditions the need to review a standard on "readily available information on the efficacy of such standard." CAA section 111(b)(1)(B). The legislative history of the 1970 CAA predecessor for the review provision also states that the review obligation depends on the availability of "new technology processes or operating methods." 1970 Sen. Comm. Rep. at 17. Additionally, the *Massachusetts* decision, which held that GHG are air pollutants, was handed down merely four weeks before the court-ordered deadline to propose the standards for this 8-year review period. As explained above, section 111(b)(1)(B) contemplates a two-year period for NSPS promulgation, and, as noted below, the consent decree under which EPA was acting contemplated a two-and-a-half year period for this 8-year review; hence, EPA did not have sufficient time within this rulemaking for proposing and promulgating performance standards for GHG emissions from refineries. The following discussion provides more information regarding the timeline of events for this particular rulemaking's review period.

EPA entered into a consent decree with the Sierra Club and Our Children's Earth Foundation on October 31, 2005, that required EPA to conduct its review of 40 CFR part 60, subpart J and propose revisions by April 30, 2007, and to promulgate a final rule by April 30, 2008. EPA began its review of subpart J and drafted a proposal package. Shortly before EPA sent the proposed rule package to OMB for its review, the U.S. Supreme Court, on April 2, 2007, issued its decision in *Massachusetts* v. *EPA*, holding that GHG are air pollutants under the CAA, and remanding the case for the Agency to take action consistent with the Court's opinion. Less than one month later, EPA was obligated under the terms of its consent decree to propose revisions to subpart J by April 30, 2007; this proposed rule did not include performance standards for GHG emissions. On August 27, 2007, EPA received comments from Earthjustice asserting that EPA, as part of its 8-year review under section 111(b)(1)(B), must promulgate GHG emissions limits for petroleum refineries. On September 14, 2007, the *Massachusetts* case was officially remanded to the Agency by the DC Circuit Court of Appeals. Under the terms of the consent decree, EPA was obligated to finalize its subpart J revisions by April 30, 2008. Considering this timeline of events, and the complexities of the issues involved, EPA would not have had sufficient time during this particular 8-year review of subpart J to propose and promulgate GHG performance standards for refineries even if the Agency had deemed such action appropriate. As explained above, the Agency will use the information it gathers through the ANPR for determining what may be appropriate for future rulemakings.

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

### *A. What are the impacts for petroleum refinery process units?*

We are presenting estimates of the impacts for the final requirements of subpart Ja that change the performance standards for the following: (1) The emission limits for fluid catalytic cracking units, sulfur recovery plants, fluid coking units, fuel gas combustion devices, and process heaters; and (2) the work practice standards for flares and delayed coking units. The final amendments to 40 CFR part 60, subpart J are clarifications to the existing rule and they have no emission reduction impacts. The cost, environmental, and economic impacts presented in this section are expressed as incremental differences between the impacts of petroleum refinery process units complying with the final subpart Ja and the current NSPS requirements of subpart J (*i.e.*, baseline). The impacts are presented for petroleum refinery process units that commence construction, reconstruction, or modification over the next 5 years. The analyses and the documents referenced below can be found in Docket ID No. EPA–HQ–OAR–2007–0011.

In order to determine the incremental costs and emission reductions of this final rule, we first estimated baseline impacts. For new sources, baseline costs and emission reductions were estimated for complying with subpart J; incremental impacts for subpart Ja were estimated as the costs to comply with subpart J subtracted from the costs to comply with final subpart Ja. Sources that are modified or reconstructed over the next 5 years must comply with subpart J in the absence of final subpart Ja. Prior to reconstruction or modification, these sources will either be subject to a consent decree

(equivalent to about 77 percent of the industry by capacity), complying with subpart J or equivalent limits, and/or complying with 40 CFR part 63, subpart UUU (MACT II). Baseline costs and emission reductions were estimated as the effort needed to comply with subpart J from one of those three starting points. The costs and emission reductions to comply with final subpart Ja were estimated from those starting points as well. For further detail on the methodology of these calculations, see Docket ID No. EPA–HQ–OAR–2007–0011.

When considering and selecting emission limits for the final rule, we evaluated the cost-effectiveness of each option for new sources separately from reconstructed and modified sources. In most cases, our selections for each process unit and pollutant were consistent for modified and reconstructed units and new units. In this section, we are presenting our costs and emission reductions for the overall rule. We estimate that the final amendments will reduce emissions of PM by 1,300 tons/yr, $SO_2$ by 17,000 tons/yr, $NO_X$ by 11,000 tons/yr, and VOC by 200 tons/yr from the baseline. The estimated increase in annual cost, including annualized capital costs, is about $31 million (2006 dollars). The overall cost-effectiveness is about $1,070 per ton of combined pollutants removed. The estimated nationwide 5-year incremental emissions reductions and cost impacts for the final standards are summarized in Table 19 of this preamble.

TABLE 19.—NATIONAL INCREMENTAL EMISSION REDUCTIONS AND COST IMPACTS FOR PETROLEUM REFINERY UNITS SUBJECT TO FINAL STANDARDS UNDER 40 CFR PART 60, SUBPART JA (FIFTH YEAR AFTER PROPOSAL)

| Process unit | Total capital cost ($1,000) | Total annual cost ($1,000/yr) | Annual emission reductions (tons PM/yr) | Annual emission reductions (tons $SO_2$/yr) | Annual emission reductions (tons $NO_X$/yr) | Annual emission reductions (tons VOC/yr) | Cost effectiveness ($/ton) |
|---|---|---|---|---|---|---|---|
| FCCU | 8,500 | 6,400 | 240 | 4,300 | 2,600 | ..... | 890 |
| FCU | 14,000 | 4,000 | 1,000 | 5,900 | 660 | ..... | 530 |
| SRP | 1,700 | 730 | ..... | 420 | ..... | ..... | 1,700 |
| Fuel gas combustion devices | 34,000 | 12,000 | ..... | 5,200 | ..... | ..... | 2,300 |
| Process heaters | 23,000 | 12,000 | ..... | ..... | 7,500 | ..... | 1,600 |
| Flaring | 40,000 | −7,000 | ..... | 80 | 6 | 200 | −23,000 |
| Delayed coking units | 17,000 | 1,600 | ..... | 440 | ..... | 25 | 3,400 |
| Sulfur pits | 8,300 | 1,000 | ..... | 300 | ..... | ..... | 3,400 |
| Total | 150,000 | 31,100 | 1,300 | 17,000 | 11,000 | 1,400 | 1,070 |

*B. What are the secondary impacts?*

Indirect or secondary air quality impacts of this final rule will result from the increased electricity usage associated with the operation of control devices. If plants purchase electricity from a power plant, we estimate that the final standards will increase secondary emissions of criteria pollutants, including PM, $SO_2$, $NO_X$, and CO from power plants. For new, modified or reconstructed sources, this final rule will increase secondary PM emissions by 56 Megagrams per year (Mg/yr) (62 tons/yr); secondary $SO_2$ emissions by about 1,400 Mg/yr (1,500 tons/yr); and secondary $NO_X$ emissions by about 530 Mg/yr (580 tons/yr) for the 5 years following proposal.

As explained earlier, we expect that affected facilities will control emissions from fluid catalytic cracking units by installing and operating ESP or wet gas scrubbers. We also expect that the emissions from the affected FCU will be controlled with a wet scrubber. For these process units, we estimated solid waste impacts for both types of control devices and water impacts for wet gas scrubbers. In addition, the controls needed by small sulfur recovery plants will generate condensate. We project that this final rule will generate 1.6 billion gallons of water per year for the 5 years following proposal. We also estimate that this final rule will generate 2,200 Mg/yr (2,400 tons/yr) of solid waste over those 5 years.

Energy impacts as defined in this preamble section consist of the electricity and steam needed to operate control devices and other equipment that would be required under the final rule. Our estimate of the increased energy demand includes the electricity needed to produce the required amounts of steam as well as direct electricity demand. We project that this final rule will increase overall energy demand by about 410 gigawatt-hours per year (1,400 billion British thermal units per year). An analysis of energy impacts that accounts for reactions in affected markets to the costs of this final rule can be found in the section on Executive Order 13211 found later in this preamble.

*C. What are the economic impacts?*

Our economic impact analysis estimated the impacts on product price and output that the final NSPS would have on five petroleum products—motor gasoline, jet fuel, distillate fuel oil, residual fuel oil, and liquefied petroleum gases. This analysis estimates in the fifth year after proposal that the price of these petroleum products will increase less than 0.01 percent nationally along with a corresponding reduction in output of less than 0.01 percent. The overall total annual social costs, which reflect changes in consumer and producer behavior in response to the compliance costs, are $27 million ($2006) in the fifth year after proposal or almost identical to the compliance costs incurred by affected producers of these petroleum products.

For more information, please refer to the regulatory impact analysis (RIA) that is in the docket for this final rule.

*D. What are the benefits?*

We estimate the monetized benefits of this final rule to be $220 million to $1.9 billion (2006$) in the fifth year after proposal. We base the benefits estimate derived from the $PM_{2.5}$ and $PM_{2.5}$ precursor emission reductions on the approach and methodology laid out in the Technical Support Document that accompanied the recently completed Regulatory Impact Analysis (RIA) for the revision to the National Ambient Air Quality Standard for Ground-level Ozone (NAAQS), March 2008. We generated estimates that represent the total monetized human health benefits (the sum of premature mortality and premature morbidity) of reducing one ton of $PM_{2.5}$ and $PM_{2.5}$ precursor

emissions. A summary of the range of benefits estimates at discount rates of 3% and 7% is in Table 20 of this preamble.

TABLE 20.—SUMMARY OF THE RANGE OF BENEFITS ESTIMATES FOR FINAL REFINERIES NSPS

| Pollutant | Monetized benefits per ton emission reduction (3% discount) | Monetized benefits per ton emission reduction (7% discount) | Emission reductions (tons) | Total monetized benefits (millions of 2006 dollars, 3% discount) [1] | Total monetized benefits (millions of 2006 dollars, 7% discount) [1] |
|---|---|---|---|---|---|
| Direct $PM_{2.5}$ | $68,000 to $570,000. | $63,000 to $520,000. | 1,054 | $72 to $600 | $66 to $540. |
| $PM_{2.5}$ Precursor: | | | | | |
| $SO_2$ | $8,000 to $68,000 | $7,400 to $62,000 | 16,714 | $130 to $1,100 | $120 to $1,000. |
| $NO_X$ | $1,300 to $11,000 | $1,200 to $9,600 | 10,786 | $14 to $110 | $13 to $100. |
| VOC | $210 to $1,700 | $190 to $1,500 | 230 | $0.05 to $.38 | $0.04 to $.35. |
| | | | Grand total | $220 to $1,900 | $200 to $1,700. |

[1] All estimates are for the analysis year (fifth year after proposal, 2012), and are rounded to two significant figures so numbers may not sum across columns. Emission reductions reflect the combination of selected options for both new and reconstructed/modified sources. The $PM_{2.5}$ fraction of total PM emissions is estimated at 83.3%, and only the reduction in the $PM_{2.5}$ fraction is monetized in this analysis. All fine particles are assumed to have equivalent health effects, but the benefit per ton estimates vary because each ton of precursor reduced has a different propensity to become $PM_{2.5}$. The monetized benefits incorporate the conversion from precursor emissions to ambient fine particles.

The specific estimates of benefits per ton of pollutant reductions included in this analysis are largely driven by the concentration response function for premature mortality, which is based on the PM Expert Elicitation study (Industrial Economics, Inc., September 2006. *Expanded Expert Judgment Assessment of the Concentration-Response Relationship Between $PM_{2.5}$ Exposure and Mortality.* Prepared for the U.S. EPA, Office of Air Quality Planning and Standards). The preamble for the proposal indicated that EPA would update the benefits estimates to incorporate the results of the expert elicitation for the final rule, and we have done so. The range of benefits estimates presented above represents the range from the lowest expert estimate to the highest expert estimate to characterize the uncertainty in the concentration response function. To generate the benefit-per-ton estimates, we used a model to convert emissions of direct $PM_{2.5}$ and $PM_{2.5}$ precursors into changes in $PM_{2.5}$ air quality and another model to estimate the changes in human health based on that change in air quality. Finally, the monetized health benefits were divided by the emission reductions to create the benefit-per-ton estimates. Even though all fine particles are assumed to have equivalent health effects, the benefit-per-ton estimates vary because each ton of precursor reduced has a different propensity to become $PM_{2.5}$. For example, $NO_X$ 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.

This analysis does not include the type of detailed uncertainty assessment found in the PM NAAQS RIA because we lack the necessary air quality input and monitoring data to run the benefits model. However, the 2006 PM NAAQS analysis provides an indication of the sensitivity of our results to the use of alternative concentration response functions, including those derived from the PM expert elicitation study.

The annualized costs of this rulemaking are estimated at $31 million (2006 dollars) in the fifth year after proposal, and the benefits are estimated at $220 million to $1.9 billion (2006 dollars) for that same year. Thus, net benefits of this rulemaking are estimated at $190 million to $1.8 billion (2006 dollars). EPA believes that the benefits are likely to exceed the costs by a significant margin even when taking into account the uncertainties in the cost and benefit estimates. It should be noted that the range of benefits estimates provided above does not include ozone-related benefits from the reductions in VOC and $NO_X$ emissions expected to occur as a result of this final rule, nor does this range include benefits from the portion of total PM emissions reduction that is not $PM_{2.5}$. We do not have sufficient information or modeling available to provide such estimates for this rulemaking. For more information, please refer to the RIA for this final rule that is available in the docket.

## VI. Statutory and Executive Order Reviews

### *A. Executive Order 12866: Regulatory Planning and 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, EPA submitted this action to the Office of Management and Budget (OMB) for review under Executive Order 12866 and any changes made in response to OMB recommendations have been documented in the docket for this action.

In addition, EPA prepared an analysis of the potential costs and benefits associated with this action. This analysis is contained in the RIA for the Final Petroleum Refinery NSPS. A copy of the analysis is available in the docket for this action and the analysis is briefly summarized here. The monetized benefits of this action are estimated as a range from $220 million to $1.9 billion (2006 dollars), and the annualized costs of this action are $31.1 million (2006 dollars). We also estimated the economic impacts, small business impacts, and energy impacts associated with this action. These analyses are included in the RIA and are summarized elsewhere in this preamble.

### *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 add a monitoring exemption for fuel gas streams combusted in a fuel gas combustion device that are inherently low in sulfur content. The exemption applies to fuel gas streams that meet specified criteria or that the owner or operator demonstrates are low sulfur according to the rule requirements. The owner or operator is required to submit a written application for the exemption containing information needed to document the low sulfur content. The application is not a mandatory requirement and the incremental reduction in monitoring burden that

will occur as a result of the exemption is not significant compared to the baseline burden estimates for the existing rule. Therefore, we have not revised the information collection request (ICR) for the existing rule. However, OMB has previously approved the information collection requirements 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, EPA ICR number 1054.09. The OMB control numbers for EPA's regulations are listed in 40 CFR part 9.

The information collection requirements in the final standards of performance for petroleum refineries (40 CFR part 60, subpart Ja) 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.

The information collection requirements in this final rule are needed by the Agency to determine compliance with the standards. These requirements are based on recordkeeping and reporting requirements in the NSPS General Provisions in 40 CFR part 60, subpart A, and on specific requirements in subpart J or subpart Ja which are mandatory for all operators subject to new source performance standards. These recordkeeping and reporting requirements are specifically authorized by section 114 of the CAA (42 U.S.C. 7414). All information submitted to EPA pursuant to the recordkeeping and reporting requirements for which a claim of confidentiality is made is safeguarded according to EPA policies set forth in 40 CFR part 2, subpart B.

The final standards of performance for petroleum refineries include work practice requirements for delayed coking reactor vessel depressuring and written plans to minimize emissions from flares. Plants also are required to analyze the cause of any exceedance that releases more than 500 pounds per day of $SO_2$ from an affected fuel gas combustion device. The final standards also include testing, monitoring, recordkeeping, and reporting provisions. Monitoring requirements include control device operating parameters, bag leak detection systems, or CEMS, depending on the type of process, pollutant, and control device. Exemptions are also included for small emitters.

The annual burden for this information collection averaged over the first 3 years of this ICR is estimated to total 5,340 labor-hours per year at a cost of $481,249 per year. The annualized capital costs are estimated at $2,052,000 per year and operation and maintenance costs are estimated at $1,117,440 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 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 EPA's regulations 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.

### *C. Regulatory Flexibility Act*

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 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 final action on small entities, small entity is defined as: (1) A small business whose parent company has no more than 1,500 employees, depending on the size definition for the affected NAICS code (as defined by Small Business Administration (SBA) size standards); (2) a small governmental jurisdiction that is a government of a city, county, town, school district, or special district with a population of less than 50,000; and (3) a small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field.

After considering the economic impact 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 the current standards of performance for petroleum refineries are small refineries. After reviewing the small business analysis for the proposed NSPS, we realized that we inadvertently used the capacity limit of 125,000 barrels/day production as part of the small business size standard to evaluate the impacts on small refiners; the definition that should have been used is 1,500 employees for an ultimate parent entity with no capacity limit in the United States. The effect of this change in the small business size standard for this analysis is one additional small refiner. This change in the small business size standard does not lead to any effect on the certification that there is no significant economic impact on a substantial number of small entities resulting from today's action. We have determined that, of the 58 entities that are in the affected industry, 25 of these (or 43 percent) are classified as small according to the SBA small business size standard listed previously. Of these 25 affected entities, three are expected to be affected by today's action. None of these three small entities is expected to incur an annualized compliance cost of more than 1.0 percent to comply with this final action. For more information, please refer to the economic impact analysis that is in the public docket for this rulemaking.

Although this final action will not have a significant economic impact on a substantial number of small entities, EPA nonetheless has tried to reduce the impact of this final action on small entities by incorporating specific standards for small sulfur recovery plants and streamlining procedures for exempting inherently low-sulfur fuel gases from continuous monitoring.

### *D. Unfunded Mandates Reform Act*

Title II of the Unfunded Mandates Reform Act (UMRA) of 1995, Public Law 104–4, establishes requirements for Federal agencies to assess the effects of their regulatory actions on State, local, and tribal governments and the private sector. Under section 202 of the UMRA, EPA generally must prepare a written statement, including a cost-benefit analysis, for proposed and final rules with "Federal mandates" that may result in expenditures by State, local, and tribal governments, in the aggregate, or to the private sector, of $100 million or more in any one year. Before promulgating an EPA rule for which a written statement is needed, section 205 of the UMRA generally requires EPA to identify and consider a reasonable number of regulatory alternatives and adopt the least costly, most cost-effective, or least burdensome alternative that achieves the objectives of the rule. The provisions of section

205 do not apply when they are inconsistent with applicable law. Moreover, section 205 allows EPA to adopt an alternative other than the least costly, most cost-effective, or least burdensome alternative if the Administrator publishes with the final rule an explanation why that alternative was not adopted. Before EPA establishes any regulatory requirements that may significantly or uniquely affect small governments, including tribal governments, it must have developed under section 203 of the UMRA a small government agency plan. The plan must provide for notifying potentially affected small governments, enabling officials of affected small governments to have meaningful and timely input in the development of EPA regulatory proposals with significant Federal intergovernmental mandates, and informing, educating, and advising small governments on compliance with the regulatory requirements.

EPA has determined that this final action 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, the estimated expenditures for the private sector in the fifth year after proposal are an annualized cost of $31.1 million (2006 dollars). Thus, this final action is not subject to the requirements of section 202 and 205 of the UMRA. In addition, EPA has determined that this final action 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 would not result in expenditures by them of $100 million or more in any one year or any disproportionate impacts on them. Therefore, this final action is not subject to the requirements of section 203 of the UMRA.

*E. Executive Order 13132: Federalism*

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

This 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 final action.

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

Executive Order 13175 (65 FR 67249, November 9, 2000) requires EPA to develop an accountable process to ensure "meaningful and timely input by tribal officials in the development of regulatory policies that have tribal implications." This final action does not have tribal implications, as specified in Executive Order 13175. 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. The final rules impose requirements on owners and operators of specified industrial facilities and not tribal governments. Thus, Executive Order 13175 does not apply to this final action.

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

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

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

This rule is not a "significant energy action" as defined in Executive Order 13211, "Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use" (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. We prepared an analysis of the impacts on energy markets as part of our RIA for this final action. This analysis accounts for the increase in electricity generation occurring due to additional control requirements associated with this final action. Our analysis shows that there is a reduction in gasoline output of less than 0.75 million gallons per year, or less than 50 barrels of gasoline production per day in the fifth year after proposal of this final action. In addition, our analysis shows that there is no increase in gasoline prices in the fifth year after proposal of this final action. With no increase in domestic gasoline prices, no significant increase in our dependence on foreign energy supplies should take place. Finally, this final action will have no adverse effect on crude oil supply, coal production, electricity production, and energy distribution. Further, we conclude that this final action is not likely to have any adverse energy effects. For more information on this analysis, please refer to the RIA available in the docket for this rulemaking.

*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 EPA to use voluntary consensus standards (VCS) 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 VCS bodies. NTTAA directs EPA to provide Congress, through OMB, explanations when the Agency decides not to use available and applicable VCS.

This rulemaking involves technical standards. EPA has decided to use the VCS ANSI/ASME PTC 19.10–1981, "Flue and Exhaust Gas Analyses," for its manual methods of measuring the content of the exhaust gas. These parts of ANSI/ASME PTC 19.10–1981 are acceptable alternatives to EPA Methods 3B, 6, 6A, 7, 7C, and 15A. This standard is available from the American Society of Mechanical Engineers (ASME), Three Park Avenue, New York, NY 10016–5990.

The EPA has also decided to use EPA methods 1, 2, 3, 3A, 3B, 5, 5B, 5F, 5I, 6, 6A, 6C, 7, 7A, 7C, 7D, 7E, 10, 10A, 10B, 11, 15, 15A, 16, and 17 (40 CFR part 60, Appendices A–1 through A6); Performance Specifications 1, 2, 3, 4, 4A, 5, 7, and 11 (40 CFR part 60, Appendix B); quality assurance procedures in 40 CFR part 60, Appendix F; and the Gas Processors Association Standard 2377–86, "Test for Hydrogen

Sulfide and Carbon Dioxide in Natural Gas Using Length of Stain Tubes," 1986 Revision. While the Agency has identified 22 VCS as being potentially applicable to this rule, we have decided not to use these VCS in this rulemaking. The use of these VCS would have been impractical because they do not meet the objectives of the standards cited in this rule. See the docket for this rule for the reasons for these determinations.

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

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

Executive Order 12898 (59 FR 7629, February 16, 1994) establishes Federal executive policy on environmental justice. Its main provision directs Federal agencies, to the greatest extent practicable and permitted by law, to make environmental justice part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority populations and low-income populations in the United States. EPA has determined that these final amendments to 40 CFR part 60, subpart J will not have disproportionately high and adverse human health or environmental effects on minority or low-income populations because they do not affect the level of protection provided to human health or the environment. The final amendments are clarifications which do not relax the control measures on sources regulated by the rule and, therefore, will not cause emissions increases from these sources.

*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 U.S. Senate, the U.S. 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 not a "major rule" as defined by 5 U.S.C. 804(2). This final rule will be effective on June 24, 2008.

**List of Subjects in 40 CFR Part 60**

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

Dated: April 30, 2008.

**Stephen L. Johnson,**

*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:

■ a. Revising paragraph (h)(4),

■ b. Revising the last sentence of paragraph (m) introductory text, and

■ c. Revising paragraph (m)(1) to read as follows:

**§ 60.17 Incorporations by reference.**

* * * * *

(h) * * *

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

* * * * *

(m) * * * You may inspect a copy at EPA's Air and Radiation Docket and Information Center, Room 3334, 1301 Constitution Ave., NW., Washington, DC 20460.

(1) Gas Processors Association Standard 2377–86, Test for Hydrogen Sulfide and Carbon Dioxide in Natural Gas Using Length of Stain Tubes, 1986 Revision, IBR approved for §§ 60.105(b)(1)(iv), 60.107a(b)(1)(iv), 60.334(h)(1), 60.4360, and 60.4415(a)(1)(ii).

* * * * *

## Subpart J—[Amended]

■ 3. Section 60.100 is amended by revising the first sentence in paragraph (a) and revising paragraphs (b) through (d) to read as follows:

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

(a) The provisions of this subpart are applicable to the following affected facilities in petroleum refineries: fluid catalytic cracking unit catalyst regenerators, fuel gas combustion devices, and all Claus sulfur recovery plants except Claus plants with a design capacity for sulfur feed of 20 long tons per day (LTD) or less. * * *

(b) Any fluid catalytic cracking unit catalyst regenerator or fuel gas combustion device under paragraph (a) of this section other than a flare as defined in § 60.101a 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 meets the definition of a flare as defined in § 60.101a 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) and (d) of this section.

(c) Any fluid catalytic cracking unit catalyst regenerator under paragraph (b) of this section which commences construction, reconstruction, or modification on or before January 17, 1984, is exempted from § 60.104(b).

(d) Any fluid catalytic cracking unit in which a contact material reacts with petroleum derivatives to improve feedstock quality and in which the contact material is regenerated by burning off coke and/or other deposits and that commences construction, reconstruction, or modification on or before January 17, 1984, is exempt from this subpart.

* * * * *

■ 4. 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 also 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 to comply with the wastewater provisions in § 60.692, 40 CFR 61.343 through 61.348, or 40 CFR 63.647, or the marine tank vessel loading provisions in 40 CFR 63.562 or 40 CFR 63.651.

* * * * *

■ 5. Section 60.102 is amended by revising paragraph (b) to read as follows:

**§ 60.102 Standard for particulate matter.**

* * * * *

(b) Where the gases discharged by the fluid catalytic cracking unit catalyst regenerator pass through an incinerator or waste heat boiler in which auxiliary or supplemental liquid or solid fossil fuel is burned, particulate matter in excess of that permitted by paragraph (a)(1) of this section may be emitted to the atmosphere, except that the incremental rate of particulate matter emissions shall not exceed 43 grams per Gigajoule (g/GJ) (0.10 lb/million British thermal units (Btu)) of heat input attributable to such liquid or solid fossil fuel.

■ 6. Section 60.104 is amended by revising paragraphs (b)(1) and (b)(2) to read as follows:

**§ 60.104 Standards for sulfur oxides.**

* * * * *

(b) * * *

(1) With an add-on control device, reduce $SO_2$ emissions to the atmosphere by 90 percent or maintain $SO_2$ emissions to the atmosphere less than or equal to 50 ppm by volume (ppmv), whichever is less stringent; or

(2) Without the use of an add-on control device to reduce $SO_2$ emissions, maintain sulfur oxides emissions calculated as $SO_2$ to the atmosphere less than or equal to 9.8 kg/Mg (20 lb/ton) coke burn-off; or

* * * * *

■ 7. Section 60.105 is amended by:

■ a. Revising the first sentence of paragraph (a)(3) introductory text;

■ b. Revising paragraph (a)(3)(iv);

■ c. Revising paragraph (a)(4) introductory text;

■ d. Adding paragraph (a)(4)(iv);

■ e. Revising paragraph (a)(8) introductory text;

■ f. Revising paragraph (a)(8)(i); and

■ g. Adding paragraph (b) to read as follows:

**§ 60.105 Monitoring of emissions and operations.**

(a) * * *

(3) For fuel gas combustion devices subject to § 60.104(a)(1), either an instrument for continuously monitoring and recording the concentration by volume (dry basis, zero percent excess air) of $SO_2$ emissions into the atmosphere or monitoring as provided in paragraph (a)(4) of this section). * * *

* * * * *

(iv) Fuel gas combustion devices having a common source of fuel gas may be monitored at only one location (i.e., after one of the combustion devices), if monitoring at this location accurately represents the $SO_2$ emissions into the atmosphere from each of the combustion devices.

(4) Instead of the $SO_2$ monitor in paragraph (a)(3) of this section for fuel gas combustion devices subject to § 60.104(a)(1), an instrument for continuously monitoring and recording the concentration (dry basis) of $H_2S$ in fuel gases before being burned in any fuel gas combustion device.

* * * * *

(iv) The owner or operator of a fuel gas combustion device is not required to comply with paragraph (a)(3) or (4) of this section for fuel gas streams that are exempt under § 60.104(a)(1) and fuel gas streams combusted in a fuel gas combustion device that are inherently low in sulfur content. Fuel gas streams meeting one of the requirements in paragraphs (a)(4)(iv)(A) through (D) of this section will be considered inherently low in sulfur content. If the composition of a fuel gas stream changes such that it is no longer exempt under § 60.104(a)(1) or it no longer meets one of the requirements in paragraphs (a)(4)(iv)(A) through (D) of this section, the owner or operator must begin continuous monitoring under paragraph (a)(3) or (4) of this section within 15 days of the change.

(A) Pilot gas for heaters and flares.

(B) Fuel gas streams that meet a commercial-grade product specification for sulfur content of 30 ppmv or less. In the case of a liquefied petroleum gas (LPG) product specification in the pressurized liquid state, the gas phase sulfur content should be evaluated assuming complete vaporization of the LPG and sulfur containing-compounds at the product specification concentration.

(C) Fuel gas streams produced in process units that are intolerant to sulfur contamination, such as fuel gas streams produced in the hydrogen plant, the catalytic reforming unit, the isomerization unit, and HF alkylation process units.

(D) Other fuel gas streams that an owner or operator demonstrates are low-sulfur according to the procedures in paragraph (b) of this section.

* * * * *

(8) An instrument for continuously monitoring and recording concentrations of $SO_2$ in the gases at both the inlet and outlet of the $SO_2$ control device from any fluid catalytic cracking unit catalyst regenerator for which the owner or operator seeks to comply specifically with the 90 percent reduction option under § 60.104(b)(1).

(i) The span value of the inlet monitor shall be set at 125 percent of the maximum estimated hourly potential $SO_2$ emission concentration entering the control device, and the span value of the outlet monitor shall be set at 50 percent of the maximum estimated hourly potential $SO_2$ emission concentration entering the control device.

* * * * *

(b) An owner or operator may demonstrate that a fuel gas stream combusted in a fuel gas combustion device subject to § 60.104(a)(1) that is not specifically exempted in § 60.105(a)(4)(iv) is inherently low in sulfur. A fuel gas stream that is determined to be low-sulfur is exempt from the monitoring requirements in paragraphs (a)(3) and (4) of this section until there are changes in operating conditions or stream composition.

(1) The owner or operator shall submit to the Administrator a written application for an exemption from monitoring. The application must contain the following information:

(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) to be considered;

(ii) A statement that there are no crossover or entry points for sour gas (high $H_2S$ content) to be introduced into the fuel gas stream/system (this should be shown in the piping diagrams);

(iii) An explanation of the conditions that ensure low amounts of sulfur in the fuel gas stream (i.e., control equipment or product specifications) at all times;

(iv) The supporting test results from sampling the requested fuel gas stream/system demonstrating that the sulfur content is less than 5 ppmv. Sampling data must include, at minimum, 2 weeks of daily monitoring (14 grab samples) for frequently operated fuel gas streams/systems; for infrequently operated fuel gas streams/systems,

seven grab samples must be collected unless other additional information would support reduced sampling. The owner or operator shall use detector tubes ("length-of-stain tube" type measurement) following the "Gas Processors Association Standard 2377–86, Test for Hydrogen Sulfide and Carbon Dioxide in Natural Gas Using Length of Stain Tubes," 1986 Revision (incorporated by reference—see § 60.17), with ranges 0–10/0–100 ppm (N = 10/1) to test the applicant fuel gas stream for $H_2S$; and

(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 (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).

(2) The effective date of the exemption is the date of submission of the information required in paragraph (b)(1) of this section).

(3) No further action is required unless refinery operating conditions change in such a way that affects the exempt fuel gas stream/system (e.g., the stream composition changes). If such a change occurs, the owner or operator will follow the procedures in paragraph (b)(3)(i), (b)(3)(ii), or (b)(3)(iii) of this section.

(i) If the operation change results in a sulfur content that is still within the range of concentrations included in the original application, the owner or operator shall conduct an $H_2S$ test on a grab sample and record the results as proof that the concentration is still within the range.

(ii) If the operation change results in a sulfur content that is outside the range of concentrations included in the original application, the owner or operator may submit new information following the procedures of paragraph (b)(1) of this section within 60 days (or within 30 days after the seventh grab sample is tested for infrequently operated process units).

(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 must determine a rolling 365-day average using the stain sampling results; an average $H_2S$ concentration of 5 ppmv must be used for days prior to the operation change.

* * * * *

■ 8. Section 60.106 is amended by revising paragraph (b)(3) introductory text and revising the first sentence of paragraph (e)(2) to read as follows:

**§ 60.106 Test methods and procedures.**

* * * * *

(b) * * *

(3) The coke burn-off rate ($R_c$) shall be computed for each run using the following equation:

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

Where:

$R_c$ = Coke burn-off rate, kilograms per hour (kg/hr) (lb/hr).

$Q_r$ = Volumetric flow rate of exhaust gas from fluid catalytic cracking unit regenerator before entering the emission control system, dscm/min (dscf/min).

$Q_a$ = Volumetric flow rate of air to fluid catalytic cracking unit regenerator, as determined from the fluid catalytic cracking unit control room instrumentation, dscm/min (dscf/min).

$Q_{oxy}$ = Volumetric flow rate of $O_2$ enriched air to fluid catalytic cracking unit regenerator, as determined from the fluid catalytic cracking unit control room instrumentation, dscm/min (dscf/min).

$\%CO_2$ = Carbon dioxide concentration in fluid catalytic cracking unit regenerator exhaust, percent by volume (dry basis).

%CO = CO concentration in FCCU regenerator exhaust, percent by volume (dry basis).

$\%O_2$ = $O_2$ concentration in fluid catalytic cracking unit regenerator exhaust, percent by volume (dry basis).

$\%O_{oxy}$ = $O_2$ concentration in $O_2$ enriched air stream inlet to the fluid catalytic cracking unit regenerator, 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)].

$K_3$ = Material balance and conversion factor, 0.0994 (kg-min)/(hr-dscm-%) [0.00624 (lb-min)/(hr-dscf-%)].

* * * * *

(e) * * *

(2) Where emissions are monitored by § 60.105(a)(3), compliance with § 60.104(a)(1) shall be determined using Method 6 or 6C and Method 3 or 3A. The method ANSI/ASME PTC 19.10–1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 6. * * *

* * * * *

■ 9. Section 60.107 is amended by:

■ a. Revising the first sentence of paragraph (c)(1)(i);

■ b. Redesignating paragraphs (e) and (f) as (f) and (g); and

■ c. Adding paragraph (e) to read as follows:

**§ 60.107 Reporting and recordkeeping requirements.**

* * * * *

(c) * * *

(1) * * *

(i) The average percent reduction and average concentration of sulfur dioxide on a dry, $O_2$-free basis in the gases discharged to the atmosphere from any fluid cracking unit catalyst regenerator for which the owner or operator seeks to comply with § 60.104(b)(1) is below 90 percent and above 50 ppmv, as measured by the continuous monitoring system prescribed under § 60.105(a)(8), or above 50 ppmv, as measured by the outlet continuous monitoring system prescribed under § 60.105(a)(9). * * *

* * * * *

(e) For each fuel gas stream combusted in a fuel gas combustion device subject to § 60.104(a)(1), if an owner or operator determines that one of the exemptions listed in § 60.105(a)(4)(iv) applies to that fuel gas stream, the owner or operator shall maintain records of the specific exemption chosen for each fuel gas stream. If the owner or operator applies for the exemption described in § 60.105(a)(4)(iv)(D), the owner or operator must keep a copy of the application as well as the letter from the Administrator granting approval of the application.

* * * * *

■ 10. Section 60.108 is amended by revising the last sentence of paragraph (e) to read as follows:

**§ 60.108 Performance test and compliance provisions.**

* * * * *

(e) * * * The owner or operator shall furnish the Administrator with a written notification of the change in the semiannual report required by § 60.107(f).

■ 11. Part 60 is amended by adding subpart Ja to read as follows:

**Subpart Ja—Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007**



## Subpart Ja—Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007

### § 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 flares and process heaters, 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, 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.

(c) For the purposes of this subpart, under § 60.14, a modification to a flare occurs if:

(1) Any new piping from a refinery process unit or fuel gas system is physically connected to the flare (e.g., for direct emergency relief or some form of continuous or intermittent venting); or

(2) A flare is physically altered to increase the flow capacity of the flare.

(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 May 14, 2007. For purposes of this paragraph, "commenced" means that an owner or operator has undertaken a continuous program of component replacement or that an owner or operator has entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of component replacement.

### § 60.101a Definitions.

Terms used in this subpart are defined in the Clean Air Act, in § 60.2, and in this section.

*Coke burn-off* means the coke removed from the surface of the FCCU catalyst by combustion in the catalyst regenerator. The rate of coke burn-off is calculated by the formula specified in § 60.104a.

*Contact material* means any substance formulated to remove metals, sulfur, nitrogen, or any other contaminant from petroleum derivatives.

*Delayed coking unit* means 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.

*Flare* means an open-flame fuel gas combustion device used for burning off unwanted gas or flammable gas and liquids. The flare includes the foundation, flare tip, structural support, burner, igniter, flare controls including air injection or steam injection systems, flame arrestors, knockout pots, piping and header systems.

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

*Fluid catalytic cracking* unit means a refinery process unit in which petroleum derivatives are continuously charged and hydrocarbon molecules in the presence of a catalyst suspended in a fluidized bed are fractured into smaller molecules, or react with a contact material suspended in a fluidized bed to improve feedstock quality for additional processing and the catalyst or contact material is continuously regenerated by burning off coke and other deposits. The unit includes the riser, reactor, regenerator, air blowers, spent catalyst or contact material stripper, catalyst or contact material recovery equipment, and regenerator equipment for controlling air pollutant emissions and for heat recovery. When *fluid catalyst cracking unit* regenerator exhaust from two separate fluid catalytic cracking units share a common exhaust treatment (e.g., CO boiler or wet scrubber), the *fluid catalytic cracking unit* is a single affected facility.

*Fluid coking unit* means one or more refinery process units 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 equipment for controlling air pollutant emissions and for heat recovery on the fluid coking burner exhaust vent.

*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, but does include gases from flexicoking unit gasifiers. *Fuel gas* does not include vapors that are collected and combusted to comply with the wastewater provisions in § 60.692, 40 CFR 61.343 through 61.348, 40 CFR 63.647, or the marine tank vessel loading provisions in 40 CFR 63.562 or 40 CFR 63.651.

*Fuel gas combustion device* means any equipment, such as process heaters, boilers, and flares, used to combust fuel gas, except facilities in which gases are combusted to produce sulfur or sulfuric acid.

*Fuel gas system* means a system of compressors, piping, knock-out pots, mix drums, and units used to remove sulfur contaminants from the fuel gas (e.g., amine scrubbers) that collects refinery fuel gas from one or more sources for treatment as necessary prior to combusting in process heaters or boilers. A *fuel gas system* may have an overpressure vent to a flare but the primary purpose for a fuel gas system is to provide fuel to the refinery.

*Oxidation control system* means an emission control system which reduces emissions from sulfur recovery plants by converting these emissions to sulfur dioxide ($SO_2$) and recycling the $SO_2$ to the reactor furnace or the first-stage catalytic reactor of the Claus sulfur recovery plant or converting the $SO_2$ to a sulfur product.

*Petroleum* means the crude oil removed from the earth and the oils derived from tar sands, shale, and coal.

*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.

*Process heater* means an enclosed combustion device used to transfer heat indirectly to process stream materials (liquids, gases, or solids) or to a heat transfer material for use in a process unit instead of steam.

*Process upset gas* means any gas generated by a petroleum refinery process unit as a result of upset or malfunction.

*Reduced sulfur compounds* means hydrogen sulfide ($H_2S$), carbonyl sulfide, and carbon disulfide.

*Reduction control system* means an emission control system which reduces emissions from sulfur recovery plants by converting these emissions to $H_2S$ and either recycling the $H_2S$ to the reactor furnace or the first-stage catalytic reactor of the Claus sulfur recovery plant or converting the $H_2S$ to a sulfur product.

*Refinery process unit* means any segment of the petroleum refinery in which a specific processing operation is conducted.

*Sulfur pit* means the storage vessel in which sulfur that is condensed after each Claus catalytic reactor is initially accumulated and stored. *A sulfur pit* does not include secondary sulfur storage vessels downstream of the initial Claus reactor sulfur pits.

*Sulfur recovery plant* means all process units which recover sulfur from $HS_2$ and/or $SO_2$ at a petroleum refinery. The *sulfur recovery plant* also includes sulfur pits used to store the recovered sulfur product, but it does not include secondary sulfur storage vessels downstream of the sulfur pits. For example, a Claus sulfur recovery plant includes: Reactor furnace and waste heat boiler, catalytic reactors, sulfur pits, and, if present, oxidation or reduction control systems, or incinerator, thermal oxidizer, or similar combustion device. Multiple sulfur recovery 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.

**§ 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 (h) 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.

(b) An owner or operator subject to the provisions of this subpart shall not discharge or cause the discharge into the atmosphere from any FCCU or FCU:

(1) Particulate matter (PM) in excess of the limits in paragraphs (b)(1)(i), (ii), or (iii) of this section.

(i) 1.0 kilogram per Megagram (kg/Mg)(1 pound (lb) per 1,000 lb) coke burn-off or, if a PM continuous emission monitoring system (CEMS) is used, 0.040 grain per dry standard cubic feet (gr/dscf) corrected to 0 percent excess air for each modified or reconstructed FCCU.

(ii) 0.5 gram per kilogram (g/kg) coke burn-off (0.5 lb PM/1,000 lb coke burn-off) or, if a PM CEMS is used, 0.020 gr/dscf corrected to 0 percent excess air for each newly constructed FCCU.

(iii) 1.0 kg/Mg (1 lb/1,000 lb) coke burn-off; or if a PM CEMS is used, 0.040 grain per dry standard cubic feet (gr/dscf) corrected to 0 percent excess air for each affected FCU.

(2) Nitrogen oxides ($NO_X$) in excess of 80 parts per million by volume (ppmv), dry basis corrected to 0 percent excess air, on a 7-day rolling average basis.

(3) Sulfur dioxide ($SO_2$) in excess of 50 ppmv dry basis corrected to 0 percent excess air, on a 7-day rolling average basis and 25 ppmv, dry basis corrected to 0 percent excess air, on a 365-day rolling average basis.

(4) Carbon monoxide (CO) in excess of 500 ppmv, dry basis corrected to 0 percent excess air, on an hourly average basis.

(c) The owner or operator of a FCCU or FCU that uses a continuous parameter monitoring system (CPMS) according to § 60.105a(b)(1) shall comply with the applicable control device parameter operating limit in paragraph (c)(1) or (2) of this section.

(1) If the FCCU or FCU is controlled using an electrostatic precipitator:

(i) The 3-hour rolling average total power and secondary current to the entire system must not fall below the level established during the most recent performance test; and

(ii) The daily average exhaust coke burn-off rate must not exceed the level established during the most recent performance test.

(2) If the FCCU or FCU is controlled using a wet scrubber:

(i) The 3-hour rolling average pressure drop must not fall below the level established during the most recent performance test; and

(ii) The 3-hour rolling average liquid-to-gas ratio must not fall below the level established during the most recent performance test.

(d) If an FCCU or FCU uses a continuous opacity monitoring system (COMS) according to the alternative monitoring option in § 60.105a(e), the 3-hour rolling average opacity of emissions from the FCCU or FCU as measured by the COMS must not exceed the site-specific opacity limit established during the most recent performance test.

(e) The owner or operator of a FCCU or FCU that is exempted from the requirement for a CO continuous emissions monitoring system under § 60.105a(h)(3) shall comply with the parameter operating limits in paragraph (e)(1) or (2) of this section.

(1) For a FCCU or FCU with no post-combustion control device:

(i) The hourly average temperature of the exhaust gases exiting the FCCU or FCU must not fall below the level established during the most recent performance test.

(ii) The hourly average oxygen ($O_2$) concentration of the exhaust gases exiting the FCCU or FCU must not fall below the level established during the most recent performance test.

(2) For a FCCU or FCU with a post-combustion control device:

(i) The hourly average temperature of the exhaust gas vent stream exiting the control device must not fall below the level established during the most recent performance test.

(ii) The hourly average $O_2$ concentration of the exhaust gas vent stream exiting the control device must not fall below the level established during the most recent performance test.

(f) Except as provided in paragraph (f)(3), each owner or operator of an affected sulfur recovery plant shall comply with the applicable emission limits in paragraphs (f)(1) or (2) of this section.

(1) For a sulfur recovery plant with a capacity greater than 20 long tons per day (LTD):

(i) For a sulfur recovery plant with an oxidation control system or a reduction control system followed by incineration, the owner or operator shall not discharge or cause the discharge of any gases into the atmosphere in excess of 250 ppm by volume (dry basis) of sulfur dioxide ($SO_2$) at zero percent excess air. If the sulfur recovery plant consists of multiple process trains or release points the owner or operator shall comply with the 250 ppmv limit for each process train or release point or comply with a flow rate weighted average of 250 ppmv for all release points from the sulfur recovery plant; or

(ii) For 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 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; or

(iii) For systems using oxygen enrichment, the owner or operator shall calculate the applicable emission limit using Equation 1 of this section:

$$E_{LS} = k_1 \times \left(-0.038 * (\%O_2)^2 + 11.53 * \%O_2 + 25.6\right) \quad \text{(Eq. 1)}$$

Where:

$E_{LS}$ = Emission rate of $SO_2$ for large sulfur recovery plant, ppmv;

$k_1$ = Constant factor for emission limit conversion: $k_1 = 1$ for converting to $SO_2$ limit and $k_1 = 1.2$ for converting to the reduced sulfur compounds limit; and

$\%O_2$ = $O_2$ concentration to the SRP, percent by volume (dry basis).

(2) For a sulfur recovery plant with a capacity of 20 LTD or less:

(i) For a sulfur recovery plant with an oxidation control system or a reduction control system followed by incineration, the owner or operator shall not discharge or cause the discharge of any gases into the atmosphere in excess of 2,500 ppm by volume (dry basis) of $SO_2$ at zero percent excess air. If the sulfur recovery plant consists of multiple process trains or release points the owner or operator shall comply with the 2,500 ppmv limit for each process train or release point or comply with a flow rate weighted average of 2,500 ppmv for all release points from the sulfur recovery plant; or

(ii) For 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 3,000 ppm by volume of reduced sulfur compounds and 100 ppm by volume of hydrogen sulfide ($H_2S$), each calculated as ppm $SO_2$ by volume (dry basis) at zero percent excess air; or

(iii) For systems using oxygen enrichment, the owner or operator shall calculate the applicable emission limit using Equation 2 of this section:

$$E_{SS} = k_1 \times \left(-0.38 * (\%O_2)^2 + 115.3 * \%O_2 + 256\right) \quad \text{(Eq. 2)}$$

Where:

$E_{SS}$ = Emission rate of $SO_2$ for small sulfur recovery plant, ppmv.

(3) Periods of maintenance of the sulfur pit, during which the emission limits in paragraphs (f)(1) and (2) shall not apply, shall not exceed 240 hours per year. The owner or operator must document the time periods during which the sulfur pit vents were not controlled and measures taken to minimize emissions during these periods. Examples of these measures include not adding fresh sulfur or shutting off vent fans.

(g) Each owner or operator of an affected fuel gas combustion device shall comply with the emission limits in paragraphs (g)(1) through (3) of this section.

(1) 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 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.

(2) For each process heater with a rated capacity of greater than 40 million British thermal units per hour (MMBtu/hr), the owner or operator shall not discharge to the atmosphere any emissions of $NO_X$ in excess of 40 ppmv (dry basis, corrected to 0 percent excess air) on a 24-hour rolling average basis.

(3) Except as provided in paragraphs (h) and (i) of this section, the owner or operator of an affected flare shall not allow flow to each affected flare during normal operations of more than 7,080 standard cubic meters per day ($m^3$/day) (250,000 standard cubic feet per day (scfd)) on a 30-day rolling average. The owner or operator of a newly constructed or reconstructed flare shall comply with the emission limit in this paragraph by no later than the date that flare becomes an affected flare subject to this subpart. The owner or operator of a modified flare shall comply with the emission limit in this paragraph by no later than 1 year after that flare becomes an affected flare subject to this subpart.

(h) 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 paragraph (g) of this section.

(i) In periods of fuel gas imbalance that are described in the flare management plan required in section 60.103a(a), compliance with the emission limit in paragraph (g)(3) of this section is demonstrated by following the procedures and maintaining records described in the flare management plan to document the periods of excess fuel gas.

**§ 60.103a Work practice standards.**

(a) Each owner or operator that operates a flare that is subject to this subpart shall develop and implement a written flare management plan. The owner or operator of a newly constructed or reconstructed flare must develop and implement the flare management plan by no later than the date that flare becomes an affected flare subject to this subpart. The owner or operator of a modified flare must develop and implement the flare management plan by no later than 1 year after the flare becomes an affected flare subject to this subpart. The plan must include:

(1) A diagram illustrating all connections to the flare;

(2) Methods for monitoring flow rate to the flare, including 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 for flare gas monitoring devices;

(3) Procedures to minimize discharges to the flare gas system during the planned start-up and shutdown of the refinery process units that are connected to the affected flare;

(4) Procedures to conduct a root cause analysis of any process upset or malfunction that causes a discharge to the flare in excess of 14,160 $m^3$/day (500,000 scfd);

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

(6) Explanation of procedures to follow during times that the flare must exceed the limit in § 60.102a(g)(3) (e.g., keep records of natural gas purchases to support assertion that the refinery is producing more fuel gas than needed to operate the processes).

(b) Each owner or operator that operates a fuel gas combustion device or sulfur recovery plant subject to this subpart shall conduct a root cause analysis of any emission limit exceedance or process start-up, shutdown, upset, or malfunction that causes a discharge to the atmosphere in excess of 227 kilograms per day (kg/day) (500 lb per day (lb/day)) of $SO_2$. For any root cause analysis performed, the owner or operator shall record the identification of the affected facility, the date and duration of the discharge, the results of the root cause analysis, and the action taken as a result of the root cause analysis. The first root cause analysis for a modified flare must be conducted no later than the first discharge that occurs after the flare has been an affected flare subject to this subpart for 1 year.

(c) Each owner or operator of a delayed coking unit shall depressure to 5 lb per square inch gauge (psig) during reactor vessel depressuring and vent the exhaust gases to the fuel gas system for combustion in a fuel gas combustion device.

**§ 60.104a Performance tests.**

(a) The owner or operator shall conduct a performance test for each FCCU, FCU, sulfur recovery plant, 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.

(b) The owner or operator of a FCCU or FCU that elects to monitor control device operating parameters according to the requirements in § 60.105a(b), to use bag leak detectors according to the requirements in § 60.105a(c), or to use COMS according to the requirements in § 60.105a(e) shall conduct a PM performance test at least once every 12 months and furnish the Administrator a written report of the results of each test.

(c) In conducting the performance tests required by this subpart (or as requested by the Administrator), the owner or operator shall use the test methods in 40 CFR part 60, Appendices A–1 through A–8 or other methods as specified in this section, except as provided in § 60.8(b).

(d) The owner or operator shall determine compliance with the PM, $NO_X$, $SO_2$, and CO emissions limits in § 60.102a(b) for FCCU and FCU using the following methods and procedures:

(1) Method 1 of Appendix A–1 to part 60 for sample and velocity traverses.

(2) Method 2 of Appendix A–1 to part 60 for velocity and volumetric flow rate.

(3) Method 3, 3A, or 3B of Appendix A–2 to part 60 for gas analysis. The method ANSI/ASME PTC 19.10–1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 3B of Appendix A–2 to part 60.

(4) Method 5, 5B, or 5F of Appendix A–3 to part 60 for determining PM emissions and associated moisture content from a FCCU or FCU without a wet scrubber subject to the emissions limit in § 63.102a(b)(1). Use Method 5 or 5B of Appendix A–3 to part 60 for determining PM emissions and associated moisture content from a FCCU or FCU with a wet scrubber subject to the emissions limit in § 63.102a(b)(1).

(i) The PM performance test consists of 3 valid test runs; the duration of each test run must be no less than 60 minutes.

(ii) The emissions rate of PM ($E_{PM}$) is computed for each run using Equation 3 of this section:

$$E = \frac{c_s \, Q_{sd}}{K \, R_c} \qquad \text{(Eq. 3)}$$

Where:

E = Emission rate of PM, g/kg, lbs per 1,000 lbs (lb/1,000 lbs) 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), lbs per hour (lbs/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 4 of this section:

$$R_c = K_1 Q_r (\%CO_2 + \%CO) + K_2 Q_a - K_3 Q_r \left(\%CO/2 + \%CO_2 + \%O_2\right) + K_3 Q_{oxy} (\%O_{oxy}) \qquad \text{(Eq. 4)}$$

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 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-dsc-%) [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-%)].

(iv) During the performance test, the volumetric flow rate of exhaust gas from catalyst regenerator ($Q_r$) before any emission control or energy recovery system that burns auxiliary fuel is measured using Method 2 of Appendix A–1 to part 60.

(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 in § 60.105a(b)(2), if applicable, using Equation 5 of this section:

$$Q_r = \frac{79 \times Q_a + (100 - \%Oxy) \times Q_{oxy}}{100 - \%CO_2 - \%CO - \%O_2} \qquad \text{(Eq. 5)}$$

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(g)(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).

(5) Method 6, 6A, or 6C of Appendix A–4 to part 60 for moisture content and for the concentration of $SO_2$; the duration of each test run must be no less than 4 hours. The method ANSI/ASME PTC 19.10–1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 6 or 6A of Appendix A–4 to part 60.

(6) Method 7, 7A, 7C, 7D, or 7E of Appendix A–4 to part 60 for moisture content and for the concentration of $NO_X$ calculated as nitrogen dioxide ($NO_2$); the duration of each test run must be no less than 4 hours. The method ANSI/ASME PTC 19.10–1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 7 or 7C of Appendix A–4 to part 60.

(7) Method 10, 10A, or 10B of Appendix A–4 to part 60 for moisture content and for the concentration of CO. The sampling time for each run must be 60 minutes.

(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 6 of this section:

$$C_{adj} = C_{meas}\left[20.9_c \Big/ (20.9 - \%O_2)\right] \qquad \text{(Eq. 6)}$$

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.

(e) The owner or operator of a FCCU or FCU that is controlled by an electrostatic precipitator or wet scrubber and that is subject to control device operating parameter limits in § 60.102a(c) shall establish the limits based on the performance test results according to the following procedures:

(1) Reduce the parameter monitoring data to hourly averages for each test run;

(2) Determine the hourly average operating limit for each required parameter as the average of the three test runs.

(f) The owner or operator of an FCCU or FCU that uses cyclones to comply with the PM limit in § 60.102a(b)(1) and elects to comply with the COMS alternative monitoring option in § 60.105a(d) shall establish a site-specific opacity operating limit according to the procedures in paragraphs (f)(1) through (3) of this section.

(1) Collect COMS data every 10 seconds during the entire period of the PM performance test and reduce the data to 6-minute averages.

(2) Determine and record the hourly average opacity from all the 6-minute averages.

(3) Compute the site-specific limit using Equation 7 of this section:

$$Opacity\ Limit = Opacity_{st} x \left(\frac{1lb/1{,}000\ lb\ coke\ burn}{PMEmR_{st}}\right) \qquad \text{(Eq. 7)}$$

Where:

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

$Opacity_{st}$ = Hourly average opacity measured during the source test runs, percent; and

$PMEmR_{st}$ = PM emission rate measured during the source test, lb/1,000 lbs coke burn.

(g) The owner or operator of a FCCU or FCU that is exempt from the requirement to install and operate a CO CEMS pursuant to § 60.105a(h)(3) and that is subject to control device operating parameter limits in § 60.102a(c) shall establish the limits based on the performance test results

using the procedures in paragraphs (g)(1) and (2) of this section.

(1) Reduce the temperature and $O_2$ concentrations from the parameter monitoring systems to hourly averages for each test run.

(2) Determine the operating limit for temperature and $O_2$ concentrations as the average of the average temperature and $O_2$ concentration for the three test runs.

(h) The owner or operator shall determine compliance with the $SO_2$ and $H_2S$ emissions limits for sulfur recovery plants in §§ 60.102a(f)(1)(i), 60.102a(f)(1)(iii), 60.102a(f)(1)(iii), 60.102a(f)(2)(i), and 60.102a(f)(2)(iii) and the reduced sulfur compounds and $H_2S$ emissions limits for sulfur recovery plants in § 60.102a(f)(1)(ii) and § 60.102a(f)(2)(ii) using the following methods and procedures:

(1) Method 1 of Appendix A–1 to part 60 for sample and velocity traverses.

(2) Method 2 of Appendix A–1 to part 60 for velocity and volumetric flow rate.

(3) Method 3, 3A, or 3B of Appendix A–2 to part 60 for gas analysis. The method ANSI/ASME PTC 19.10–1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 3B of Appendix A–2 to part 60.

(4) Method 6, 6A, or 6C of Appendix A–4 to part 60 to determine the $SO_2$ concentration. The method ANSI/ASME PTC 19.10–1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 6 or 6A of Appendix A–4 to part 60.

(5) Method 15 or 15A of Appendix A–5 to part 60 or Method 16 of Appendix A–6 to part 60 to determine the reduced sulfur compounds and $H_2S$ concentrations. The method ANSI/ASME PTC 19.10–1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 15A of Appendix A–5 to part 60.

(i) Each run consists of 16 samples taken over a minimum of 3 hours.

(ii) The owner or operator shall calculate the average $H_2S$ concentration after correcting for moisture and $O_2$ as the arithmetic average of the $H_2S$ concentration for each sample during the run (ppmv, dry basis, corrected to 0 percent excess air).

(iii) The owner or operator shall calculate the $SO_2$ equivalent for each run after correcting for moisture and $O_2$ as the arithmetic average of the $SO_2$ equivalent of reduced sulfur compounds for each sample during the run (ppmv, dry basis, corrected to 0 percent excess air).

(iv) The owner or operator shall use Equation 6 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:

(1) Method 1 of Appendix A–1 to part 60 for sample and velocity traverses;

(2) Method 2 of Appendix A–1 to part 60 for velocity and volumetric flow rate;

(3) Method 3, 3A, or 3B of Appendix A–2 to part 60 for gas analysis. The method ANSI/ASME PTC 19.10–1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 3B of Appendix A–2 to part 60;

(4) Method 6, 6A, or 6C of Appendix A–4 to part 60 to determine the $SO_2$ concentration. The method ANSI/ASME PTC 19.10–1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 6 or 6A of Appendix A–4 to part 60.

(i) The performance test consists of 3 valid test runs; the duration of each test run must be no less than 1 hour.

(ii) If a single fuel gas combustion device having a common source of fuel gas is monitored as allowed under § 60.107a(a)(1)(v), only one performance test is required. That is, performance tests are not required when a new affected fuel gas combustion device is added to a common source of fuel gas that previously demonstrated compliance.

(5) Method 7, 7A, 7C, 7D, or 7E of Appendix A–4 to part 60 for moisture content and for the concentration of $NO_X$ calculated as $NO_2$; the duration of each test run must be no less than 4 hours. The method ANSI/ASME PTC 19.10–1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 7 or 7C of Appendix A–4 to part 60.

(j) The owner or operator shall determine compliance with the $H_2S$ emissions limit in § 60.102a(g) for a fuel gas combustion device according to the following test methods and procedures:

(1) Method 1 of Appendix A–1 to part 60 for sample and velocity traverses;

(2) Method 2 of Appendix A–1 to part 60 for velocity and volumetric flow rate;

(3) Method 3, 3A, or 3B of Appendix A–2 to part 60 for gas analysis. The method ANSI/ASME PTC 19.10–1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 3B of Appendix A–2 to part 60;

(4) Method 11, 15, or 15A of Appendix A–5 to part 60 or Method 16 of Appendix A–6 to part 60 for determining the $H_2S$ concentration for affected plants using an $H_2S$ monitor as specified in § 60.107a(a)(2). The method ANSI/ASME PTC 19.10–1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 15A of Appendix A–5 to part 60. The owner or operator may demonstrate compliance based on the mixture used in the fuel gas combustion device or for each individual fuel gas stream used in the fuel gas combustion device.

(i) For Method 11 of Appendix A–5 to part 60, the sampling time and sample volume must be at least 10 minutes and 0.010 dscm (0.35 dscf). Two samples of equal sampling times must be taken at about 1-hour intervals. The arithmetic average of these two samples constitutes a run. For most fuel gases, sampling times exceeding 20 minutes may result in depletion of the collection solution, although fuel gases containing low concentrations of $H_2S$ may necessitate sampling for longer periods of time.

(ii) For Method 15 of Appendix A–5 to part 60, at least three injects over a 1-hour period constitutes a run.

(iii) For Method 15A of Appendix A–5 to part 60, a 1-hour sample constitutes a run. The method ANSI/ASME PTC 19.10–1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 15A of Appendix A–5 to part 60.

(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 is added to a common source of fuel gas that previously demonstrated compliance.

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

(a) *FCCU and FCU subject to PM emissions limit.* Each owner or operator subject to the provisions of this subpart shall monitor each FCCU and FCU subject to the PM emissions limit in § 60.102a(b)(1) according to the requirements in paragraph (b), (c), (d), or (e) of this section.

(b) *Control device operating parameters.* Each owner or operator of a FCCU or FCU subject to the PM per coke burn-off emissions limit in § 60.102a(b)(1) shall comply with the requirements in paragraphs (b)(1) through (3) 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 requirements in paragraph (b)(1)(i) through (iii) of this section.

(i) For units controlled using an electrostatic precipitator, the owner or operator shall use CPMS to measure and record the hourly average total power input and secondary voltage to the entire system.

(ii) For units controlled using a wet scrubber, the owner or operator shall use CPMS to measure and record the hourly average pressure drop, liquid feed rate, and exhaust gas flow rate. As an alternative to a CPMS, the owner or operator must comply with the requirements in either paragraph (b)(1)(ii)(A) or (B) of this section.

(A) As an alterative 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.

(B) As an alternative to exhaust gas flow rate, the owner or operator shall comply with the approved alternative for monitoring exhaust gas flow rate in 40 CFR 63.1573(a) of the National Emission Standards for Hazardous Air Pollutants for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units.

(iii) The owner or operator shall install, operate, and maintain each CPMS according to the manufacturer's specifications and requirements.

(iv) The owner or operator shall determine and record the average coke burn-off rate and hours of operation for each FCCU or FCU using the procedures in § 60.104a(d)(4)(iii).

(v) If you use a control device other than an electrostatic precipitator, wet scrubber, fabric filter, or cyclone, you may request approval to monitor parameters other than those required in paragraph (b)(1) of this section by submitting an alternative monitoring plan to the Administrator. The request must include the information in paragraphs (b)(1)(v)(A) through (E) of this section.

(A) A description of each affected facility and the parameter(s) to be monitored to determine whether the affected facility will continuously comply with the emission limitations and an explanation of the criteria used to select the parameter(s).

(B) A description of the methods and procedures that will be used to demonstrate that the parameter(s) can be used to determine whether the affected facility will continuously comply with the emission limitations and the schedule for this demonstration. The owner or operator must certify that an operating limit will be established for the monitored parameter(s) that represents the conditions in existence when the control device is being properly operated and maintained to meet the emission limitation.

(C) The frequency and content of the recordkeeping, recording, and reporting, if monitoring and recording are not continuous. The owner or operator also must include the rationale for the proposed monitoring, recording, and reporting requirements.

(D) Supporting calculations.

(E) Averaging time for the alternative operating parameter.

(2) For use in determining the coke burn-off rate for an FCCU or FCU, the owner or operator shall install, operate, calibrate, and maintain an instrument for continuously monitoring the concentrations of $CO_2$, $O_2$ (dry basis), and if needed, CO in the exhaust gases prior to any control or energy recovery system that burns auxiliary fuels.

(i) The owner or operator shall install, operate, and maintain each monitor according to Performance Specification 3 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 Specification 3 of Appendix B to part 60. The owner or operator shall use Method 3 of Appendix A–3 to part 60 for conducting the relative accuracy evaluations.

(iii) The owner or operator shall comply with the quality assurance requirements of procedure 1 of Appendix F to part 60, including quarterly accuracy determinations for $CO_2$ and CO monitors, annual accuracy determinations for $O_2$ monitors, and daily calibration drift tests.

(c) *Bag leak detection systems.* Each owner or operator shall install, operate, and maintain a bag leak detection system for each baghouse or similar fabric filter control device that is used to comply with the PM per coke burn-off emissions limit in § 60.102a(b)(1) for an FCCU or FCU according to paragraph (c)(1) of this section; prepare and operate by a site-specific monitoring plan according to paragraph (c)(2) of this section; take action according to paragraph (c)(3) of this section; and record information according to paragraph (c)(4) of this section.

(1) Each bag leak detection system must meet the specifications and requirements in paragraphs (c)(1)(i) through (viii) of this section.

(i) The bag leak detection system must be certified by the manufacturer to be capable of detecting PM emissions at concentrations of 0.00044 grains per actual cubic foot or less.

(ii) The bag leak detection system sensor must provide output of relative PM loadings. The owner or operator shall continuously record the output from the bag leak detection system using electronic or other means (e.g., using a strip chart recorder or a data logger).

(iii) The bag leak detection system must be equipped with an alarm system that will sound when the system detects an increase in relative particulate loading over the alarm set point established according to paragraph (c)(1)(iv) of this section, and the alarm must be located such that it can be heard by the appropriate plant personnel.

(iv) In the initial adjustment of the bag leak detection system, the owner or operator must establish, at a minimum, the baseline output by adjusting the sensitivity (range) and the averaging period of the device, the alarm set points, and the alarm delay time.

(v) Following initial adjustment, the owner or operator shall not adjust the averaging period, alarm set point, or alarm delay time without approval from the Administrator or delegated authority except as provided in paragraph (c)(1)(vi) of this section.

(vi) Once per quarter, the owner or operator may adjust the sensitivity of the bag leak detection system to account for seasonal effects, including temperature and humidity, according to the procedures identified in the site-specific monitoring plan required by paragraph (c)(2) of this section.

(vii) The owner or operator shall install the bag leak detection sensor downstream of the baghouse and upstream of any wet scrubber.

(viii) Where multiple detectors are required, the system's instrumentation and alarm may be shared among detectors.

(2) The owner or operator shall develop and submit to the Administrator for approval a site-specific monitoring plan for each baghouse and bag leak detection system. The owner or operator shall operate and maintain each baghouse and bag leak detection system according to the site-specific monitoring plan at all times. Each monitoring plan must describe the items in paragraphs (c)(2)(i) through (vii) of this section.

(i) Installation of the bag leak detection system;

(ii) Initial and periodic adjustment of the bag leak detection system, including how the alarm set-point will be established;

(iii) Operation of the bag leak detection system, including quality assurance procedures;

(iv) How the bag leak detection system will be maintained, including a routine maintenance schedule and spare parts inventory list;

(v) How the bag leak detection system output will be recorded and stored;

(vi) Procedures as specified in paragraph (c)(3) of this section. In approving the site-specific monitoring plan, the Administrator or delegated authority may allow owners and operators more than 3 hours to alleviate a specific condition that causes an alarm if the owner or operator identifies in the monitoring plan this specific condition as one that could lead to an alarm, adequately explains why it is not feasible to alleviate this condition within 3 hours of the time the alarm occurs, and demonstrates that the requested time will ensure alleviation of this condition as expeditiously as practicable; and

(vii) How the baghouse system will be operated and maintained, including monitoring of pressure drop across baghouse cells and frequency of visual inspections of the baghouse interior and baghouse components such as fans and dust removal and bag cleaning mechanisms.

(3) For each bag leak detection system, the owner or operator shall initiate procedures to determine the cause of every alarm within 1 hour of the alarm. Except as provided in paragraph (c)(2)(vi) of this section, the owner or operator shall alleviate the cause of the alarm within 3 hours of the alarm by taking whatever action(s) are necessary. Actions may include, but are not limited to the following:

(i) Inspecting the baghouse for air leaks, torn or broken bags or filter media, or any other condition that may cause an increase in particulate emissions;

(ii) Sealing off defective bags or filter media;

(iii) Replacing defective bags or filter media or otherwise repairing the control device;

(iv) Sealing off a defective baghouse compartment;

(v) Cleaning the bag leak detection system probe or otherwise repairing the bag leak detection system; or

(vi) Shutting down the process producing the particulate emissions.

(4) The owner or operator shall maintain records of the information specified in paragraphs (c)(4)(i) through (iii) of this section for each bag leak detection system.

(i) Records of the bag leak detection system output;

(ii) Records of bag leak detection system adjustments, including the date and time of the adjustment, the initial bag leak detection system settings, and the final bag leak detection system settings; and

(iii) The date and time of all bag leak detection system alarms, the time that procedures to determine the cause of the alarm were initiated, the cause of the alarm, an explanation of the actions taken, the date and time the cause of the alarm was alleviated, and whether the alarm was alleviated within 3 hours of the alarm.

(d) *Continuous emissions monitoring systems (CEMS).* An owner or operator subject to the PM concentration emission limit (in gr/dscf) in § 60.102a(b)(1) for an FCCU or FCU shall install, operate, calibrate, and maintain an instrument for continuously monitoring and recording the concentration (0 percent excess air) of PM in the exhaust gases prior to release to the atmosphere. The monitor must include an $O_2$ monitor for correcting the data for excess air.

(1) The owner or operator shall install, operate, and maintain each PM monitor according to Performance Specification 11 of appendix B to part 60. The span value of this PM monitor is 0.08 gr/dscf PM.

(2) The owner or operator shall conduct performance evaluations of each PM monitor according to the requirements in § 60.13(c) and Performance Specification 11 of appendix B to part 60. The owner or operator shall use EPA Methods 5 or 5I of Appendix A–3 to part 60 or Method 17 of Appendix A–6 to part 60 for conducting the relative accuracy evaluations.

(3) The owner or operator shall install, operate, and maintain each $O_2$ monitor according to Performance Specification 3 of appendix B to part 60. The span value of this $O_2$ monitor must be selected between 10 and 25 percent, inclusive.

(4) The owner or operator shall conduct performance evaluations of each $O_2$ monitor according to the requirements in § 60.13(c) and Performance Specification 3 of Appendix B to part 60. Method 3, 3A, or 3B of Appendix A–2 to part 60 shall be used for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10–1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 3B of Appendix A–2 to part 60.

(5) The owner or operator shall comply with the quality assurance requirements of Procedure 2 of Appendix B to part 60 for each PM CEMS and Procedure 1 of Appendix F to part 60 for each $O_2$ monitor, including quarterly accuracy determinations for each PM monitor, annual accuracy determinations for each $O_2$ monitor, and daily calibration drift tests.

(e) *Alternative monitoring option for FCCU and FCU—COMS.* Each owner or operator of an FCCU or FCU that uses cyclones to comply with the PM emission limit in § 60.102a(b)(1) shall monitor the opacity of emissions according to the requirements in paragraphs (e)(1) through (3) of this section.

(1) The owner or operator shall install, operate, and maintain an instrument for continuously monitoring and recording the opacity of emissions from the FCCU or the FCU exhaust vent.

(2) The owner or operator shall install, operate, and maintain each COMS according to Performance Specification 1 of Appendix B to part 60. The instrument shall be spanned at 20 to 60 percent opacity.

(3) The owner or operator shall conduct performance evaluations of each COMS according to § 60.13(c) and Performance Specification 1 of Appendix B to part 60.

(f) *FCCU and FCU subject to $NO_X$ limit.* Each owner or operator subject to the $NO_X$ emissions limit in § 60.102a(b)(2) for an FCCU or FCU shall install, operate, calibrate, and maintain an instrument for continuously monitoring and recording the concentration by volume (dry basis, 0 percent excess air) of $NO_X$ emissions into the atmosphere. The monitor must include an $O_2$ monitor for correcting the data for excess air.

(1) The owner or operator shall install, operate, and maintain each $NO_X$ monitor according to Performance Specification 2 of Appendix B to part 60. The span value of this $NO_X$ monitor is 200 ppmv $NO_X$.

(2) The owner or operator shall conduct performance evaluations of each $NO_X$ monitor according to the requirements in § 60.13(c) and Performance Specification 2 of Appendix B to part 60. The owner or operator shall use Methods 7, 7A, 7C, 7D, or 7E of Appendix A–4 to part 60 for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10–1981, "Flue and Exhaust Gas

Analyses," (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 7 or 7C of Appendix A–4 to part 60.

(3) The owner or operator shall install, operate, and maintain each $O_2$ monitor according to Performance Specification 3 of Appendix B to part 60. The span value of this $O_2$ monitor must be selected between 10 and 25 percent, inclusive.

(4) The owner or operator shall conduct performance evaluations of each $O_2$ monitor according to the requirements in § 60.13(c) and Performance Specification 3 of Appendix B to part 60. Method 3, 3A, or 3B of Appendix A–2 to part 60 shall be used for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10–1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 3B of Appendix A–2 to part 60.

(5) The owner or operator shall comply with the quality assurance requirements of Procedure 1 of Appendix F to part 60 for each $NO_X$ and $O_2$ monitor, including quarterly accuracy determinations for $NO_X$ monitors, annual accuracy determinations for $O_2$ monitors, and daily calibration drift tests.

(g) *FCCU and FCU subject to $SO_2$ limit.* The owner or operator subject to the $SO_2$ emissions limit in § 60.102a(b)(3) for an FCCU or an FCU shall install, operate, calibrate, and maintain an instrument for continuously monitoring and recording the concentration by volume (dry basis, corrected to 0 percent excess air) of $SO_2$ emissions into the atmosphere. The monitor shall include an $O_2$ monitor for correcting the data for excess air.

(1) The owner or operator shall install, operate, and maintain each $SO_2$ monitor according to Performance Specification 2 of Appendix B to part 60. The span value of this $SO_2$ monitor is 200 ppmv $SO_2$.

(2) The owner or operator shall conduct performance evaluations of each $SO_2$ monitor according to the requirements in § 60.13(c) and Performance Specification 2 of Appendix B to part 60. The owner or operator shall use Methods 6, 6A, or 6C of Appendix A–4 to part 60 for conducting the relative accuracy evaluations. The method ANSI / ASME PTC 19.10–1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 6 or 6A of Appendix A–4 to part 60.

(3) The owner or operator shall install, operate, and maintain each $O_2$ monitor according to Performance Specification 3 of Appendix B to part 60. The span value of this $O_2$ monitor must be selected between 10 and 25 percent, inclusive.

(4) The owner or operator shall conduct performance evaluations of each $O_2$ monitor according to the requirements in § 60.13(c) and Performance Specification 3 of Appendix B to part 60. Method 3, 3A, or 3B of Appendix A–2 to part 60 shall be used for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10–1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 3B of Appendix A–2 to part 60.

(5) The owner or operator shall comply with the quality assurance requirements in Procedure 1 of Appendix F to part 60 for each $SO_2$ and $O_2$ monitor, including quarterly accuracy determinations for $SO_2$ monitors, annual accuracy determinations for $O_2$ monitors, and daily calibration drift tests.

(h) *FCCU and fluid coking units subject to CO emissions limit.* Except as specified in paragraph (h)(3) of this section, the owner or operator shall install, operate, calibrate, and maintain an instrument for continuously monitoring and recording the concentration by volume (dry basis) of CO emissions into the atmosphere from each FCCU and FCU subject to the CO emissions limit in § 60.102a(b)(4).

(1) The owner or operator shall install, operate, and maintain each CO monitor according to Performance Specification 4 or 4A of Appendix B to part 60. The span value for this instrument is 1,000 ppm CO.

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

(3) A CO CEMS need not be installed if the owner or operator demonstrates that all hourly average CO emissions are and will remain less than 50 ppmv (dry basis) corrected to 0 percent excess air. The Administrator may revoke this exemption from monitoring upon a determination that CO emissions on an hourly average basis have exceeded 50 ppmv (dry basis) corrected to 0 percent excess air, in which case a CO CEMS shall be installed within 180 days.

(i) The demonstration shall consist of continuously monitoring CO emissions for 30 days using an instrument that meets the requirements of Performance Specification 4 or 4A of Appendix B to part 60. The span value shall be 100 ppm CO instead of 1,000 ppm, and the relative accuracy limit shall be 10 percent of the average CO emissions or 5 ppm CO, whichever is greater. For instruments that are identical to Method 10 of Appendix A–4 to part 60 and employ the sample conditioning system of Method 10A of Appendix A–4 to part 60, the alternative relative accuracy test procedure in section 10.1 of Performance Specification 2 of Appendix B to part 60 may be used in place of the relative accuracy test.

(ii) The owner or operator must submit the following information to the Administrator:

(A) The measurement data specified in paragraph (h)(3)(i) of this section along with all other operating data known to affect CO emissions; and

(B) Descriptions of the CPMS for exhaust gas temperature and $O_2$ monitor required in paragraph (h)(4) of this section and operating limits for those parameters to ensure combustion conditions remain similar to those that exist during the demonstration period.

(iii) The effective date of the exemption from installation and operation of a CO CEMS is the date of submission of the information and data required in paragraph (h)(3)(ii) of this section.

(4) The owner or operator of a FCCU or FCU that is exempted from the requirement to install and operate a CO CEMS in paragraph (h)(3) of this section shall install, operate, calibrate, and maintain CPMS to measure and record the operating parameters in paragraph (h)(4)(i) or (ii) of this section. The owner or operator shall install, operate, and maintain each CPMS according to the manufacturer's specifications.

(i) For a FCCU or FCU with no post-combustion control device, the temperature and $O_2$ concentration of the exhaust gas stream exiting the unit.

(ii) For a FCCU or FCU with a post-combustion control device, the temperature and $O_2$ concentration of the exhaust gas stream exiting the control device.

(i) *Excess emissions.* For the purpose of reports required by § 60.7(c), periods of excess emissions for a FCCU or FCU subject to the emissions limitations in § 60.102a(b) are defined as specified in paragraphs (i)(1) through (6) of this section. Note: Determine all averages, except for opacity, as the arithmetic average of the applicable 1-hour averages, *e.g.*, determine the rolling 3-hour average as the arithmetic average of three contiguous 1-hour averages.

(1) If a CPMS is used according to § 60.105a(b)(1), all 3-hour periods during which the average PM control device operating characteristics, as measured by the continuous monitoring systems under § 60.105a(b)(1), fall below the levels established during the performance test.

(2) If a PM CEMS is used according to § 60.105a(d), all 7-day periods during which the average PM emission rate, as measured by the continuous PM monitoring system under § 60.105a(d) exceeds 0.040 gr/dscf corrected to 0 percent excess air for a modified or reconstructed FCCU, 0.020 gr/dscf corrected to 0 percent excess air for a newly constructed FCCU, or 0.040 gr/dscf for an affected fluid coking unit.

(3) If a COMS is used according to § 60.105a(e), all 3-hour periods during which the average opacity, as measured by the COMS under § 60.105a(e), exceeds the site-specific limit established during the most recent performance test.

(4) All rolling 7-day periods during which the average concentration of $NO_X$ as measured by the $NO_X$ CEMS under § 60.105a(f) exceeds 80 ppmv for an affected FCCU or FCU.

(5) Except as provided in paragraph (i)(7) of this section, 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.

(6) All 1-hour periods during which the average CO concentration as measured by the CO continuous monitoring system under §1A60.105a(h) exceeds 500 ppmv or, if applicable, all 1-hour periods during which the average temperature and $O_2$ concentration as measured by the continuous monitoring systems under § 60.105a(h)(4) fall below the operating limits established during the performance test.

**§ 60.106a Monitoring of emissions and operations for sulfur recovery plants.**

(a) The owner or operator of a sulfur recovery plant that is subject to the emissions limits in § 60.102a(f)(1) or § 60.102a(f)(2) shall:

(1) For sulfur recovery plants subject to the $SO_2$ emission limit in § 60.102a(f)(1)(i) or § 60.102a(f)(2)(i), the owner or operator shall install, operate, calibrate, and maintain an instrument for continuously monitoring and recording the concentration (dry basis, zero percent excess air) of any $SO_2$ emissions into the atmosphere. The monitor shall include an oxygen monitor for correcting the data for excess air.

(i) The span values for this monitor are two times the applicable $SO_2$ emission limit and between 10 and 25 percent $O_2$, inclusive.

(ii) The owner or operator shall install, operate, and maintain each $SO_2$ CEMS according to Performance Specification 2 of Appendix B to part 60.

(iii) The owner or operator shall conduct performance evaluations of each $SO_2$ monitor according to the requirements in § 60.13(c) and Performance Specification 2 of Appendix B to part 60. The owner or operator shall use Methods 6 or 6C of Appendix A–4 to part 60 and Method 3 or 3A of Appendix A–2 of part 60 for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10–1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 6.

(2) For sulfur recovery plants that are subject to the reduced sulfur compound and $H_2S$ emission limit in § 60.102a(f)(1)(ii) or § 60.102a(f)(2)(ii), the owner or operator shall install, operate, calibrate, and maintain an instrument for continuously monitoring and recording the concentration of reduced sulfur, $H_2S$, and $O_2$ emissions into the atmosphere. The reduced sulfur emissions shall be calculated as $SO_2$ (dry basis, zero percent excess air).

(i) The span values for this monitor are two times the applicable reduced sulfur emission limit, two times the $H_2S$ emission limit, and between 10 and 25 percent $O_2$, inclusive.

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

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

(iv) The owner or operator shall install, operate, and maintain each $H_2S$ CEMS according to Performance Specification 7 of Appendix B to part 60.

(v) The owner or operator shall conduct performance evaluations of each reduced sulfur monitor according to the requirements in § 60.13(c) and Performance Specification 5 of Appendix B to part 60. The owner or operator shall use Methods 11, 15, or 15A of Appendix A–5 to part 60 or Method 16 of Appendix A–6 to part 60 for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10–1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 15A of Appendix A–5 to part 60.

(vi) The owner or operator shall install, operate, and maintain each $O_2$ monitor according to Performance Specification 3 of Appendix B to part 60.

(vii) The span value for the $O_2$ monitor must be selected between 10 and 25 percent, inclusive.

(viii) The owner or operator shall conduct performance evaluations for the $O_2$ monitor according to the requirements of § 60.13(c) and Performance Specification 3 of Appendix B to part 60. The owner or operator shall use Methods 3, 3A, or 3B of Appendix A–2 to part 60 for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10–1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 3B of Appendix A–2 to part 60.

(ix) The owner or operator shall comply with the applicable quality assurance procedures of Appendix F to part 60 for each monitor, including annual accuracy determinations for each $O_2$ monitor, and daily calibration drift determinations.

(3) In place of the reduced sulfur monitor required in paragraph (a)(2) of this section, the owner or operator shall install, calibrate, operate, and maintain an instrument using an air or $O_2$ dilution and oxidation system to convert any reduced sulfur to $SO_2$ for continuously monitoring and recording the concentration (dry basis, 0 percent excess air) of the total resultant $SO_2$. The monitor must include an $O_2$ monitor for correcting the data for excess $O_2$.

(i) The span value for this monitor is two times the applicable $SO_2$ emission limit.

(ii) The owner or operator shall conduct performance evaluations of each $SO_2$ monitor according to the requirements in § 60.13(c) and Performance Specification 5 of Appendix B to part 60. The owner or operator shall use Methods 15 or 15A of

Appendix A–5 to part 60 for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10–1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 15A of Appendix A–5 to part 60.

(iii) The owner or operator shall install, operate, and maintain each $O_2$ monitor according to Performance Specification 3 of Appendix B to part 60.

(iv) The span value for the $O_2$ monitor must be selected between 10 and 25 percent, inclusive.

(v) The owner or operator shall conduct performance evaluations for the $O_2$ monitor according to the requirements of § 60.13(c) and Performance Specification 3 of Appendix B to part 60. The owner or operator shall use Methods 3, 3A, or 3B of Appendix A–2 to part 60 for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10–1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 3B of Appendix A–2 to part 60.

(vi) The owner or operator shall comply with the applicable quality assurance procedures of Appendix F to part 60 for each monitor, including quarterly accuracy determinations for each $SO_2$ monitor, annual accuracy determinations for each $O_2$ monitor, and daily calibration drift determinations.

(b) *Excess emissions.* For the purpose of reports required by § 60.7(c), periods of excess emissions for sulfur recovery plants subject to the emissions limitations in § 60.102a(f) are defined as specified in paragraphs (b)(1) through (3) of this section. **Note:** Determine all averages as the arithmetic average of the applicable 1-hour averages, e.g., determine the rolling 12-hour average as the arithmetic average of 12 contiguous 1-hour averages.

(1) All 12-hour periods 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 the applicable emission limit (dry basis, zero percent excess air); or

(2) All 12-hour periods during which the average concentration of reduced sulfur (as $SO_2$) as measured by the reduced sulfur continuous monitoring system required under paragraph (a)(2) of this section exceeds the applicable emission limit; or

(3) All 12-hour periods 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 the applicable emission limit (dry basis, 0 percent excess air).

**§ 60.107a Monitoring of emissions and operations for fuel gas combustion devices.**

(a) *Fuel gas combustion devices subject to $SO_2$ or $H_2S$ limit.* The owner or operator of a fuel gas combustion device that is subject to the requirements in § 60.102a(g) shall comply with the requirements in paragraph (a)(1) of this section for $SO_2$ emissions or paragraph (a)(2) of this section for $H_2S$ emissions.

(1) The owner or operator of a fuel gas combustion device subject to 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.

(i) The owner or operator shall install, operate, and maintain each $SO_2$ monitor according to Performance Specification 2 of Appendix B to part 60. The span value for the $SO_2$ monitor is 50 ppm $SO_2$.

(ii) The owner or operator shall conduct performance evaluations for the $SO_2$ monitor according to the requirements of § 60.13(c) and Performance Specification 2 of Appendix B to part 60. The owner or operator shall use Methods 6, 6A, or 6C of Appendix A–4 to part 60 for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10–1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 6 or 6A of Appendix A–4 to part 60. Samples taken by Method 6 of Appendix A–4 to part 60 shall be taken at a flow rate of approximately 2 liters/min for at least 30 minutes. The relative accuracy limit shall be 20 percent or 4 ppm, whichever is greater, and the calibration drift limit shall be 5 percent of the established span value.

(iii) The owner or operator shall install, operate, and maintain each $O_2$ monitor according to Performance Specification 3 of Appendix B to part 60. The span value for the $O_2$ monitor must be selected between 10 and 25 percent, inclusive.

(iv) The owner or operator shall conduct performance evaluations for the $O_2$ monitor according to the requirements of § 60.13(c) and Performance Specification 3 of Appendix B to part 60. The owner or operator shall use Methods 3, 3A, or 3B of Appendix A–2 to part 60 for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10–1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 3B of Appendix A–2 to part 60.

(v) The owner or operator shall comply with the applicable quality assurance procedures in Appendix F to part 60, including quarterly accuracy determinations for $SO_2$ monitors, annual accuracy determinations for $O_2$ monitors, and daily calibration drift tests.

(vi) Fuel gas combustion devices having a common source of fuel gas may be monitored at only one location (i.e., after one of the combustion devices), if monitoring at this location accurately represents the $SO_2$ emissions into the atmosphere from each of the combustion devices.

(2) The owner or operator of a fuel gas combustion device subject to the $H_2S$ concentration limits in § 60.102a(g)(1)(ii) 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.

(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 320 ppmv $H_2S$.

(ii) The owner or operator shall conduct performance evaluations for each $H_2S$ monitor according to the requirements of § 60.13(c) and Performance Specification 7 of Appendix B to part 60. The owner or operator shall use Method 11, 15, or 15A of Appendix A–5 to part 60 or Method 16 of Appendix A–6 to part 60 for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10–1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 15A of Appendix A–5 to part 60.

(iii) The owner or operator shall comply with the applicable quality assurance procedures in Appendix F to part 60 for each $H_2S$ monitor.

(iv) Fuel gas combustion devices 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.

(3) The owner or operator of a fuel gas combustion device is not required to comply with paragraph (a)(1) or (2) of this section for fuel gas streams that are

exempt under § 60.102a(h) and fuel gas streams combusted in a process heater or other fuel gas combustion device 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.

(i) Pilot gas for heaters and flares.

(ii) Fuel gas streams that meet a commercial-grade product specification for sulfur content of 30 ppmv or less. In the case of a liquefied petroleum gas (LPG) product specification in the pressurized liquid state, the gas phase sulfur content should be evaluated assuming complete vaporization of the LPG and sulfur containing-compounds at the product specification concentration.

(iii) Fuel gas streams produced in process units that are intolerant to sulfur contamination, such as fuel gas streams produced in the hydrogen plant, catalytic reforming unit, isomerization unit, and HF alkylation process units.

(iv) Other fuel gas streams that an owner or operator demonstrates are low-sulfur according to the procedures in paragraph (b) of this section.

(4) If the composition of an exempt fuel gas stream changes, the owner or operator must follow the procedures in paragraph (b)(3) of this section.

(b) *Exemption from $H_2S$ monitoring requirements for low-sulfur fuel gas streams.* The owner or operator of a fuel gas combustion device 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) The owner or operator shall submit to the Administrator a written application for an exemption from monitoring. The application must contain the following information:

(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) to be considered;

(ii) A statement that there are no crossover or entry points for sour gas (high $H_2S$ content) to be introduced into the fuel gas stream/system (this should be shown in the piping diagrams);

(iii) An explanation of the conditions that ensure low amounts of sulfur in the fuel gas stream (i.e., control equipment or product specifications) at all times;

(iv) The supporting test results from sampling the requested fuel gas stream/system demonstrating that the sulfur content is less than 5 ppm $H_2S$. Sampling data must include, at minimum, 2 weeks of daily monitoring (14 grab samples) for frequently operated fuel gas streams/systems; for infrequently operated fuel gas streams/systems, seven grab samples must be collected unless other additional information would support reduced sampling. The owner or operator shall use detector tubes ("length-of-stain tube" type measurement) following the "Gas Processors Association Standard 2377–86, Test for Hydrogen Sulfide and Carbon Dioxide in Natural Gas Using Length of Stain Tubes," 1986 Revision (incorporated by reference—see § 60.17), with ranges 0–10/0–100 ppm (N = 10/1) to test the applicant fuel gas stream for $H_2S$; and

(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 (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).

(2) The effective date of the exemption is the date of submission of the information required in paragraph (b)(1) of this section.

(3) No further action is required unless refinery operating conditions change in such a way that affects the exempt fuel gas stream/system (e.g., the stream composition changes). If such a change occurs, the owner or operator shall follow the procedures in paragraph (b)(3)(i), (b)(3)(ii), or (b)(3)(iii) of this section.

(i) If the operation change results in a sulfur content that is still within the range of concentrations included in the original application, the owner or operator shall conduct an $H_2S$ test on a grab sample and record the results as proof that the concentration is still within the range.

(ii) If the operation change results in a sulfur content that is outside the range of concentrations included in the original application, the owner or operator may submit new information following the procedures of paragraph (b)(1) of this section within 60 days (or within 30 days after the seventh grab sample is tested for infrequently operated process units).

(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 must determine a rolling 365-day average using the stain sampling results; an average $H_2S$ concentration of 5 ppmv must be used for days prior to the operation change.

(c) *Process heaters subject to $NO_X$ limit.* The owner or operator of a process heater subject to the $NO_X$ emission limit in § 60.102a(g)(2) 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. The monitor must include an $O_2$ monitor for correcting the data for excess air.

(1) The owner or operator shall install, operate, and maintain each $NO_X$ monitor according to Performance Specification 2 of Appendix B to part 60. The span value of this $NO_X$ monitor is 200 ppmv $NO_X$.

(2) The owner or operator shall conduct performance evaluations of each $NO_X$ monitor according to the requirements in § 60.13(c) and Performance Specification 2 of Appendix B to part 60. The owner or operator shall use Methods 7, 7A, 7C, 7D, or 7E of Appendix A–4 to part 60 for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10–1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 7 or 7C of Appendix A–4 to part 60.

(3) The owner or operator shall install, operate, and maintain each $O_2$ monitor according to Performance Specification 3 of Appendix B to part 60. The span value of this $O_2$ monitor must be selected between 10 and 25 percent, inclusive.

(4) The owner or operator shall conduct performance evaluations of each $O_2$ monitor according to the requirements in § 60.13(c) and

Performance Specification 3 of Appendix B to part 60. Method 3, 3A, or 3B of Appendix A–2 to part 60 shall be used for conducting the relative accuracy evaluations. The method ANSI/ASME PTC 19.10–1981, "Flue and Exhaust Gas Analyses," (incorporated by reference—see § 60.17) is an acceptable alternative to EPA Method 3B of Appendix A–2 to part 60.

(5) The owner or operator shall comply with the quality assurance requirements in Procedure 1 of Appendix F to part 60 for each $NO_X$ and $O_2$ monitor, including quarterly accuracy determinations for $NO_X$ monitors, annual accuracy determinations for $O_2$ monitors, and daily calibration drift tests.

(6) The owner or operator of a process heater that has a rated heating capacity of less than 100 MMBtu and is equipped with low-$NO_X$ burners (LNB) or ultra low-$NO_X$ burners (ULNB) is not subject to the monitoring requirements in paragraphs (c)(1) through (5) of this section. The owner or operator of such a process heater must conduct biennial performance tests to demonstrate compliance.

(d) *Sulfur monitoring for affected flares.* The owner or operator of an affected flare subject to § 60.103a(b) shall install, operate, calibrate, and maintain an instrument for continuously monitoring and recording the concentration of reduced sulfur in flare gas. The owner or operator of a modified flare shall install this instrument by no later than 1 year after the flare becomes an affected flare subject to this subpart.

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

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

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

(e) *Flow monitoring for flares.* The owner or operator of an affected flare subject to § 60.102a(g)(3) shall install, operate, calibrate, and maintain CPMS to measure and record the exhaust gas flow rate. The owner or operator of a modified flare shall install this instrument by no later than 1 year after the flare becomes an affected flare subject to this subpart.

(1) The CPMS must be able to correct for the temperature and pressure of the system and output flow in standard conditions as defined in § 60.2.

(2) The owner or operator shall install, operate, and maintain each CPMS according to the manufacturer's specifications and requirements.

(f) *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) are defined as specified in paragraphs (f)(1) through (4) of this section. **Note:** Determine all averages as the arithmetic average of the applicable 1-hour averages, e.g., determine the rolling 3-hour average as the arithmetic average of three contiguous 1-hour averages.

(1) All rolling 3-hour periods 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 all rolling 365-day periods during which the average concentration as measured by the $SO_2$ continuous monitoring system required under paragraph (a)(1) of this section exceeds 8 ppmv; or

(2) All rolling 3-hour periods 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, all days in which the concentration of $H_2S$ as measured by daily stain tube sampling required under paragraph (b)(3)(iii) of this section exceeds 162 ppmv, and all rolling 365-day periods during which the average concentration as measured by the $H_2S$ continuous monitoring system under paragraph (a)(2) of this section exceeds 60 ppmv.

(3) All rolling 24-hour periods during which the average concentration of $NO_X$ as measured by the $NO_X$ continuous monitoring system required under paragraph (c) of this section exceeds 40 ppmv.

(4) All rolling 30-day periods during which the average flow rate to an affected flare as measured by the monitoring system required under paragraph (e) of this section exceeds 250,000 scfd.

**§ 60.108a Recordkeeping and reporting requirements.**

(a) Each owner or operator subject to the emissions limitations in § 60.102a shall comply with the notification, recordkeeping, and reporting requirements in § 60.7 and other requirements as specified in this section.

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

(c) The owner or operator shall maintain the following records:

(1) A copy of the flare management plan and each root cause analysis of a discharge;

(2) Records of information to document conformance with bag leak detection system operation and maintenance requirements in § 60.105a(c).

(3) Records of bag leak detection system alarms and actions according to § 60.105a(c).

(4) For each FCCU and fluid coking unit subject to the monitoring requirements in § 60.105a(b)(1), records of the average coke burn-off rate and hours of operation.

(5) For each fuel gas stream to which one of the exemptions listed in § 60.107a(a)(3) applies, records of the specific exemption determined to apply for each fuel stream. If the owner or operator applies for the exemption described in § 60.107a(a)(3)(iv), the owner or operator must keep a copy of the application as well as the letter from the Administrator granting approval of the application.

(6) The owner or operator shall record and maintain records of discharges greater than 500 lb/day $SO_2$ from any affected fuel gas combustion device or sulfur recovery plant and discharges to an affected flare in excess of 500,000 scfd. These records shall include:

(i) A description of the discharge.

(ii) For discharges greater than 500 lb/day $SO_2$, 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. Engineering calculations are allowed for fuel gas combustion devices other than flares.

(iv) For discharges greater than 500 lb/day $SO_2$, the measured or estimated

concentration of $H_2S$, TRS and $SO_2$ of the stream discharged. Process knowledge can be used to make these estimates for fuel gas combustion devices other than flares.

(v) For discharges greater than 500 lb/day $SO_2$, 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 to $SO_2$. For other fuel gas combustion devices, assume 99 percent conversion of $H_2S$ to $SO_2$.

(vi) Results of any root-cause analysis conducted as required in § 60.103a(a)(4) and § 60.103a(b).

(d) Each owner or operator subject to this subpart shall submit an excess emissions report for all periods of excess emissions according to the requirements of § 60.7(c) except that the report shall contain the information specified in paragraphs (d)(1) through (7) of this section.

(1) The date that the exceedance occurred;

(2) An explanation of the exceedance;

(3) Whether the exceedance was concurrent with a startup, shutdown, or malfunction of an affected facility or control system; and

(4) A description of the action taken, if any.

(5) A root-cause summary report that provides the information described in paragraph (e)(6) of this section for all discharges for which a root-cause analysis was required by § 60.103a(a)(4) and § 60.103a(b).

(6) For any periods for which monitoring data are not available, any changes made in operation of the emission control system during the period of data unavailability which could affect the ability of the system to meet the applicable emission limit. Operations of the control system and affected facility during periods of data unavailability are to be compared with operation of the control system and affected facility before and following the period of data unavailability.

(7) A written statement, signed by a responsible official, certifying the accuracy and completeness of the information contained in the report.

**§ 60.109a Delegation of authority.**

(a) This subpart can be implemented and enforced by the U.S. EPA or a delegated authority such as a State, local, or tribal agency. You should contact your U.S. EPA Regional Office to find out if this subpart is delegated to a State, local, or tribal agency within your State.

(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 (3) of this section are retained by the Administrator of the U.S. EPA and are not transferred to the State, local, or tribal agency.

(1) Approval of a major change to test methods under § 60.8(b). A "major change to test method" is defined in 40 CFR 63.90.

(2) Approval of a major change to monitoring under § 60.13(i). A "major change to monitoring" is defined in 40 CFR 63.90.

(3) Approval of a major change to recordkeeping/reporting under § 60.7(b) through (f). A "major change to recordkeeping/reporting" is defined in 40 CFR 63.90.

[FR Doc. E8–13498 Filed 6–23–08; 8:45 am]

BILLING CODE 6560–50–P

high water and 33 feet at mean low water. The existing drawbridge operation regulations are listed at 33 CFR 117.224.

The waterway has seasonal recreational vessels, fishing vessels, and U.S. Navy vessels of various sizes. The U.S. Navy and other marine facilities were notified regarding this deviation and no objections were received.

The owner of the bridge, National Railroad Passenger Corporation (Amtrak), requested a temporary deviation to facilitate rehabilitation construction at the bridge.

Under this temporary deviation the Amtrak Bridge, mile 3.0, across the Thames River at New London may remain in the closed position from June 1, 2008, through June 13, 2008, and from June 18, 2008, through June 20, 2008.

From June 21, 2008, through June 30, 2008, the draw may remain in the closed position; except that, the draw shall open for the passage of vessel traffic during the following time periods:

Monday through Friday from: 5 a.m. to 5:40 a.m.; 11:20 a.m. to 11:55 a.m.; 3:35 p.m. to 4:15 p.m.; and 8:30 p.m. to 8:55 p.m.

Saturday from: 8:30 a.m. to 9:10 a.m.; 12:35 p.m. to 1:05 p.m.; 3:40 p.m. to 4:10 p.m.; 5:35 p.m. to 6:05 p.m.; and 7:35 p.m. to 8:40 p.m.

Sunday from: 8:30 a.m. to 9:20 a.m.; 11:35 a.m. to 12:15 p.m.; 1:30 p.m. to 1:55 p.m.; 6:30 p.m. to 7:10 p.m.; and 8:30 p.m. to 9:15 p.m.

The draw shall open on signal at any time for U.S. Navy submarines and their associated escort vessels.

Vessels that can pass under the bridge without a bridge opening may do so at all times.

In accordance with 33 CFR 117.35(e), the bridge must return to its regular operating schedule immediately at the end of the designated time period. This deviation from the operating regulations is authorized under 33 CFR 117.35.

Dated: May 9, 2008.

**Gary Kassof,**

*Bridge Program Manager, First Coast Guard District.*

[FR Doc. E8–11437 Filed 5–21–08; 8:45 am]

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## ENVIRONMENTAL PROTECTION AGENCY

### 40 CFR Part 51

### Requirements for Preparation, Adoption, and Submittal of Implementation Plans

*CFR Correction*

In title 40 of the Code of Federal Regulations, parts 50 to 51, revised as of July 1, 2007, on page 296, in § 51.357, remove paragraphs (b)(1)(i) and (b)(1)(ii).

[FR Doc. E8–11525 Filed 5–21–08; 8:45 am]

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## ENVIRONMENTAL PROTECTION AGENCY

### 40 CFR Part 52

### Approval and Promulgation of Implementation Plans; Mississippi

*CFR Correction*

In title 40 of the Code of Regulations, part 52.1019 to End, revised as of July 1, 2007, on page 222, in section 52.1270, in the table in paragraph (c), under APC-S-2, the entry for Section VI, is corrected in the column titled "EPA approval date", is corrected to read "7/10/2006, 71 FR 38775".

[FR Doc. E8–11526 Filed 5–21–08; 8:45 am]

BILLING CODE 1505–01–D

## ENVIRONMENTAL PROTECTION AGENCY

### 40 CFR Part 60

**[EPA–HQ–OAR–2002–0071; FRL–8568–7]**

**RIN 2060–AP13**

### Update of Continuous Instrumental Test Methods: Technical Amendments

**AGENCY:** Environmental Protection Agency (EPA).

**ACTION:** Final rule.

**SUMMARY:** EPA is taking final action to correct errors in a final rule published May 15, 2006, that updated five continuous instrumental test methods. As published, the rule contained inadvertent errors and provisions that needed to be clarified. We published a direct final rule with a parallel proposed rule on September 7, 2007 to correct the errors and to add clarifying language. However, we received an adverse comment on the direct final rule, and it was subsequently withdrawn on November 5, 2007. This action finalizes the parallel proposal. In this final rule, EPA corrects errors, clarifies certain provisions, and responds to the adverse comment received on the direct final rule published on September 7, 2007.

**DATES:** This final rule is effective on May 22, 2008.

**ADDRESSES:** EPA has established a docket for this action under Docket ID No. EPA–HQ–OAR–2002–0071. 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.*, 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 through *www.regulations.gov* or in hard copy at the Update of Continuous Instrumental Test Methods Docket, Docket ID No. EPA–OAR–2002–0071, EPA Docket Center, EPA/DC, EPA West, Room 3334, 1301 Constitution Ave., NW., Washington, DC. This Docket Facility is open from 8:30 a.m. to 4:30 p.m. Monday through Friday excluding legal holidays. The Docket telephone number is (202) 566–1742. 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.

**FOR FURTHER INFORMATION CONTACT:** Mr. Foston Curtis, Air Quality Assessment Division, Office of Air Quality Planning and Standards (E143–02), Environmental Protection Agency, Research Triangle Park, North Carolina 27711; telephone number (919) 541–1063; fax number (919) 541–0516; e-mail address: *curtis.foston@epa.gov.*

**SUPPLEMENTARY INFORMATION:**

**Table of Contents**

## I. Does This Action Apply to Me?

This rule applies to certain sources that are subject to New Source Performance Standards (40 CFR part 60), are required to conduct continuous emission monitoring pursuant to 40 CFR Part 75, or are subject to other regulations that require the use of Method 3A, of Appendix A–1, Methods 6C, 7E of Appendix A–4, and Method 20 of Appendix A–7 to 40 CFR Part 60.

Regulated Entities. Categories and entities potentially affected include the following:

| Category | NAICS[a] | Examples of regulated entities |
|---|---|---|
| Industry | 332410 | Fossil Fuel Steam Generators. |
| Industry | 332410 | Industrial, Commercial, Institutional Steam Generating Units. |
| Industry | 332410 | Electric Generating Units. |
| Industry | 333611 | Stationary Gas Turbines. |
| Industry | 324110 | Petroleum Refineries. |
| Industry | 562213 | Municipal Waste Combustors. |
| Industry | 322110 | Kraft Pulp Mills. |
| Industry | 325188 | Sulfuric Acid Plants. |

[a] North American Industry Classification System.

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. This table lists examples of the types of entities EPA is now aware could potentially be affected by the final rule. Other types of entities not listed could also be affected. If you have any questions regarding the applicability of this action to a particular entity, consult the person listed in the preceding **FOR FURTHER INFORMATION CONTACT** section.

## II. Where Can I Obtain a Copy of This Action?

In addition to being available in the docket, an electronic copy of this rule will also be available on the Worldwide Web (www) through the Technology Transfer Network (TTN). Following the Administrator's signature, a copy of the final rule will be placed 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.

## III. Background

Methods 3A, 6C, 7E, 10, and 20 measure oxygen, carbon dioxide, sulfur dioxide, nitrogen oxides, and carbon monoxide emissions from stationary sources. They are prescribed for use in determining compliance with a number of Federal, State, and local regulations. The EPA published updates to simplify, harmonize, and update these test methods on May 15, 2006 (71 FR 28081). The rule promulgating these updates became effective August 14, 2006. As published, the rule contained inadvertent errors and provisions that needed clarification.

On September 7, 2007, EPA simultaneously published a proposed rule (72 FR 51392) and a direct final rule (72 FR 51365) to correct errors and clarify certain provisions in the May 15, 2006 rule. Because EPA received one adverse comment during the public comment period, EPA withdrew the direct final rule on November 5, 2007 (72 FR 62414). EPA is taking final action on the corrections and clarifications proposed for approval on September 7, 2007, and is responding to the adverse comment received in response to that proposal.

## IV. This Action

In this final rule, EPA corrects errors and clarifies portions of the May 15, 2006 rule to reflect the intent of the rule and to make it more understandable.

Specifically, EPA is taking the following actions:

### *A. Method 3A—40 CFR Part 60, Appendix A–1*

1. We are clearly stating that pre-cleaned or scrubbed air may be used for the high-level calibration gas provided no interfering gases are present.

2. An incorrect reference in Section 8.1 to Section 8.2 of Method 3 for sampling to determine gas molecular weight is corrected to reference Section 8.2.1 of Method 3.

### *B. Method 6C—40 CFR Part 60, Appendix A–4*

In Section 6.2, a reference to Section 6.2.8.1 for dual-range analyzers is expanded to include Section 6.2.8.2 which also applies.

### *C. Method 7E—40 CFR Part 60, Appendix A–4*

1. Under the descriptions for calibration gases in Section 3.3, the quality of zero gas allowed for instrument calibration is clarified. The current requirement is that all calibration gases be of EPA traceability protocol quality. However, the traceability protocol does not have a specification for zero gas. Therefore, we are adopting the specification for "zero air material" in 40 CFR 72.2 for zero gas in place of the traceability protocol.

2. In Section 3.4, we recommend the instrument calibration span be chosen such that emission concentrations are between 20 to 100 percent of the calibration span, "to the extent practicable." We are adding a note, as an example, that meeting this 20 to 100 percent criterion may not be practicable when emissions are low relative to the emission limit and the purpose of the test is to show compliance with the emission limit.

3. Section 3.9 is clarified to note that drift is the difference between the pre- and post-run system bias checks instead of the difference between the measurement system readings for the pre- and post-run bias checks.

4. Section 3.12 is corrected to remove erroneous citations to 40 CFR 53.55 and 53.56 which have nothing to do with the manufacturer's stability test (MST).

5. In Section 6.2.2, we are specifically stating that the particulate media must be included in the system bias test only when using out-of-stack filters.

6. In Section 6.2.6, the description of the calibration gas manifold is clarified to note that blocking the sample flow is not necessary when in direct calibration

mode, as suggested in the current method, but the calibration gas may simply supply an excess of calibration gas through the system.

7. The method implies that all analyzers with calibration spans of 20 ppmv or less are required to perform the MST. In Section 6.2.8.2, we are clarifying the MST requirement to note that it is only required for those analyzers that are routinely calibrated with a calibration span of 20 ppmv or less.

8. The new converter efficiency check that was added in Section 16.2.2 requires the nitrogen dioxide ($NO_2$) test gas be of EPA traceability protocol quality. Subsequent discussions with the National Institute of Standards and Technology (NIST) concerning the quality of the NIST $NO_2$ standard revealed that this standard contains small but consistent amounts of nitric acid ($HNO_3$). Some converters may not be able to completely convert this $HNO_3$ to nitric oxide (NO) for analysis. There are also concerns about the cost and stability of certified $NO_2$ gas over time. We are, therefore, dropping the new requirement that the converter efficiency gas be of EPA traceability protocol quality and reverting to the previous requirement that the gas be of a manufacturer-certified concentration. In addition, for this converter check procedure, the gas is required to be in the 40 to 60 ppmv range while the two alternative procedures require gas in the mid- to high-calibration range. We are dropping the 40 to 60 ppmv requirement in favor of recommending the concentration be in the mid- to high-calibration range in order to keep the three procedures consistent. Subsequent references to the 40 to 60 ppmv requirement have been deleted from the method.

9. In Section 7.2, we are clearly stating that the appropriate test gases listed in Table 7E–3, or others not listed that can potentially interfere, as noted elsewhere, must be used for the test. We are also making it clear that the gases used should be manufacturer-certified but are not required to be prepared by the EPA traceability protocol.

10. In Section 8.1.2, we are explicitly stating that the required stratification test is to be performed at each test site except for small stacks that are less than 4 inches in diameter.

11. In Section 8.2.1, we are making it clear that testers must obtain a certificate from the gas manufacturer documenting the quality of the calibration gas.

12. In Section 8.2.4, we are clearly stating that the converter efficiency test may be performed either before or after a test or after a series of tests.

13. In Section 8.2.7, paragraph (1) is reworded to add clarity to the interference test, and paragraph (2) is corrected to note that the interference test is valid for the life of the instrument unless major components are replaced with different model parts.

14. In the sample traversing procedure in Section 8.4, we delete redundant language in paragraphs (1) and (2).

15. In paragraph (1) of Section 8.5, we clarify the handling of failed post-run bias checks by removing unnecessary wording.

16. In Section 10.0, we clearly state that analyzers which measure NO and $NO_2$ without using a converter must be calibrated with both NO and $NO_2$. The current wording is not clear to some users.

17. In Section 12.1, we are revising certain definitions to reflect the corrections being made to the calculations.

18. In Section 12.4, we correct the system calibration error equation by adding a term for the dilution factor.

19. In Section 12.6, we add a missing equation for calculating sample concentration when a non-zero gas is used as the low-level calibration gas.

20. In Section 12.9 we replace the erroneous equation added in the updates rule with the one traditionally used by the method.

21. In Section 12.11, we correct the equation for calculating the spike recovery.

22. In Section 13.5, we are adding the 2 percent limit for the alternative converter efficiency test.

23. In Section 16.2.2, we are deleting the procedures in paragraphs (2) and (3) because they are not needed for the test and are confusing.

24. In Section 16.3, the erroneous references to 40 CFR 53.55 and 53.56 are removed; only 53.53 is followed for the MST. A note is added to clarify that alternative procedures or documentation of instrument stability are acceptable.

25. In Table 7E–3, the title is edited to note that the table contains example interference gases and concentrations. We are removing a table footnote instructing dilution extractive systems to use the hot wet concentrations because it may not be applicable in all cases. In its place, a footnote is added to remind the tester to use the highest gas concentration expected at test sites for the interference test.

26. In Table 7E–5, we correct the typographical error listing the $NO_X$ concentration at ".80% of calibration span" to read "80% of calibration span." We have removed the note to evaluate each model by the MST at least quarterly or once per 50 production units because it is not necessary.

*D. Method 20—40 CFR Part 60, Appendix A–7*

1. In Section 8.4, we are adding a minimum sample run time of 21 minutes.

## V. Public Comments on the Proposed Rule

Two public comment letters were received on the direct final rule that was published on September 7, 2007. Because the comments was considered adverse, the direct final rule was withdrawn on November 5, 2007 (72 FR 62414). One commenter identified an error in the definition of "system bias." We inadvertently proposed to change the definition to note that system bias is calculated from the difference between the system calibration response and the manufacturer certified gas concentration and not from the difference between the system calibration response and the direct calibration responses. Therefore, we are not revising the definition of system bias as indicated in the September 7, 2007, notice.

Another commenter asked that we amend the suggested gas concentrations that were proposed for the Method 7E converter check to make it clear that gases in the 40 to 60 ppm range were not the only ones allowed but that other concentrations were acceptable if they were more appropriate for the source conditions. We agree and have made this change in the final rule.

Another error in the published equation for calculating system calibration error was pointed out. The dilution factor was not in the correct place in Equation 7E–3. This has been corrected.

## VI. Judicial Review

Under section 307(b)(1) of the Clean Air Act (CAA), judicial review of this final rule is available by filing a petition for review in the U.S. Court of Appeals for the District of Columbia Circuit by July 21, 2008. 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 action may not be challenged separately in any civil or criminal proceedings brought by EPA to enforce these requirements.

## VII. Statutory and Executive Order Reviews

*A. Executive Order 12866: Regulatory Planning and 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 the Executive Order.

*B. Paperwork Reduction Act*

This action does not impose an information collection burden under the provisions of the *Paperwork Reduction Act*, 44 U.S.C. 3501 *et seq.* Burden is defined at 5 CFR 1320.3(b). These amendments do not add information collection requirements beyond those currently required under the applicable regulation. The amendments being made correct technical inaccuracies in the existing testing methodology.

*C. Regulatory Flexibility Act*

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 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 whose parent company has fewer than 100 or 1,000 employees, or fewer than 4 billion kilowatt-hr per year of electricity usage, depending on the size definition for the affected North American Industry Classification System code; (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 final rule on small entities, I certify that this action will not have a significant economic impact on a substantial number of small entities. This final rule will not impose any requirements on small entities because it does not impose any additional regulatory requirements.

*D. Unfunded Mandates Reform Act*

Title II of the Unfunded Mandates Reform Act of 1995 (UMRA), Public Law 104–4, establishes requirements for Federal agencies to assess the effects of their regulatory actions on State, local, and tribal governments and the private sector. Under section 202 of the UMRA, EPA generally must prepare a written statement, including a cost-benefit analysis, for proposed and final rules with "Federal mandates" that may result in expenditures to State, local, and tribal governments, in the aggregate, or to the private sector, of $100 million or more in any 1 year. Before promulgating an EPA rule for which a written statement is needed, section 205 of the UMRA generally requires EPA to identify and consider a reasonable number of regulatory alternatives and adopt the least costly, most cost-effective or least burdensome alternative that achieves the objectives of the rule. The provisions of section 205 do not apply when they are inconsistent with applicable law. Moreover, section 205 allows EPA to adopt an alternative other than the least costly, most cost-effective, or least burdensome alternative if the Administrator publishes with the final rule an explanation why that alternative was not adopted. Before EPA establishes any regulatory requirements that may significantly or uniquely affect small governments, including tribal governments, it must have developed, under section 203 of the UMRA a small government agency plan. The plan must provide for notifying potentially affected small governments, enabling officials of affected small governments to have meaningful and timely input in the development of EPA regulatory proposals with significant Federal intergovernmental mandates, and informing, educating, and advising small governments on compliance with the regulatory requirements.

EPA has determined that this final 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, nor does this rule significantly or uniquely impact small governments, because it contains no requirements that apply to such governments or impose obligations upon them. Thus, this rule is not subject to the requirements of sections 202 and 205 of the UMRA. EPA has determined that this rule 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. Thus, this rule is not subject to the requirements of sections 202 and 205 of the UMRA.

*E. Executive Order 13132: Federalism*

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

This final rule does not have federalism implications. It will not have substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government, as specified in Executive Order 13132. The amendments in this rule will benefit State and local governments by clarifying and correcting provisions they currently implement. No added responsibilities or increase in implementation efforts or costs for State and local governments are being added in this action. Thus, Executive Order 13132 does not apply to this rule.

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

Executive Order 13175 entitled "Consultation and Coordination with Indian Tribal Governments" (65 FR 67249, November 9, 2000) requires EPA to develop an accountable process to ensure "meaningful and timely input by tribal officials in the development of regulatory policies that have tribal implications." This final rule does not have tribal implications as specified in Executive Order 13175. 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 rule.

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

EPA interprets EO 13045 (62 FR 19885, April 23, 1997) as applying only to those regulatory actions that concern

health or safety risks, such that the analysis required under section 5–501 of the EO has the potential to influence the regulation. This action is not subject to EO 13045 because it does not establish an environmental standard intended to mitigate health or safety risks.

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

This rule is not subject to Executive Order 13211, "Actions Concerning Regulations that Significantly Affect Energy Supply, Distribution, or Use" (66 FR 28355, May 22, 2001) because it is not a significant regulatory action under Executive Order 12866.

*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, 12(d) (15 U.S.C. 272 note) directs 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 EPA to provide Congress, through OMB, explanations when the Agency decides not to use available and applicable voluntary consensus standards.

This action does not involve technical standards. Therefore, EPA did not consider 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 (Feb. 16, 1994)) establishes Federal executive policy on environmental justice. Its main provision directs federal agencies, to the greatest extent practicable and permitted by law, to make environmental justice part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority populations and low-income populations in the United States.

EPA has determined that this 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. This final rule does not relax the control measures on sources regulated by the rule and, therefore, will not cause emissions increases from these sources.

*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. 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 not a "major rule" as defined by 5 U.S.C. 804(2). This rule will be effective May 22, 2008.

**List of Subjects in 40 CFR Part 60**

Environmental protection, Administrative practice and procedures, Air pollution control, Intergovernmental relations, Reporting and recordkeeping requirements.

Dated: May 15, 2008.

**Stephen L. Johnson,**

*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—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

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

**Authority:** 23 U.S.C. 101; 42 U.S.C. 7401–7671q.

**Appendix A–2—[Amended] /**

■ 2. Amend Method 3A as follows:

■ a. Add a sentence after the second sentence of Section 7.1.

■ b. Revise the second sentence in Section 8.1.

**Method 3A—Determination of Oxygen and Carbon Dioxide Concentrations in Emissions From Stationary Sources (Instrumental Analyzer Procedure)**

* * * * *

*7.1 Calibration Gas.* * * * Pre-cleaned or scrubbed air may be used for the $O_2$ high-calibration gas provided it does not contain other gases that interfere with the $O_2$ measurement.

* * * * *

*8.1. Sampling Site and Sampling Points.* * * * In that case, you may use single-point integrated sampling as described in Section 8.2.1 of Method 3.

* * * * *

**Appendix A–4—[Amended]**

■ 3. Amend Method 6C by revising the last sentence in Section 6.2 to read as follows:

**Method 6C—Determination of Sulfur Dioxide Emissions From Stationary Sources (Instrumental Analyzer Procedure)**

* * * * *

*6.2* * * * The low-range and dual-range analyzer provisions in Sections 6.2.8.1 and 6.2.8.2 of Method 7E apply.

* * * * *

■ 4. Amend Method 7E as follows:

■ a. Revise Sections 3.3, 3.4, and 3.9.

■ b. Revise Section 3.12 by removing the third sentence and adding two new sentences.

■ c. Revise Section 6.2.2.

■ d. Revise the second sentence in Section 6.2.6.

■ e. Revise Section 6.2.8.2.

■ f. Add a sentence after the second sentence in Section 7.1.

■ g. Revise Section 7.1.4.

■ h. Revise Section 7.2.

■ i. Add three sentences to the beginning of Section 8.1.2.

■ j. Revise the second sentence in Section 8.2.1.

■ k. Revise the first sentence in Section 8.2.4.

■ l. Revise Section 8.2.4.1.

■ m. Revise the first and second sentences in paragraph (1) and the second sentence in paragraph (2) of Section 8.2.7.

■ n. Revise paragraphs (1) and (2) in Section 8.4.

■ o. Revise the introductory paragraph and paragraph (1) of Section 8.5.

■ p. In Section 9.0, revise the table entitled "Summary Table of QA/QC" by amending the entry for "M" "System Performance" "$NO_2$–NO conversion efficiency" "≥ 90% of certified test gas concentration" "before each test."

■ q. Revise the last sentence in paragraph (1) of Section 10.0.

■ r. Add definitions for "$C_{native}$," "$C_{OA}$," and "DF" in alphabetical order to Section 12.1.

■ s. Remove the definition for "$NO_{final}$" in Section 12.1.

■ t. Revise the definitions of "$C_0$" and "$SB_f$" in Section 12.1.

■ u. Revise Section 12.4.

■ v. Revise Sections 12.6 and 12.9.

■ w. Revise Equation 7E–12 in Section 12.11.

■ x. Revise Section 13.5.
■ y. Revise the third sentence in paragraph (1) of Section 16.2.2.
■ z. Remove and reserve paragraph (2) and remove paragraph (3) of Section 16.2.2.
■ aa. Revise Section 16.3.
■ bb. Revise Table 7E–3.
■ cc. Revise Table 7E–5.

**Method 7E—Determination of Nitrogen Oxides Emissions From Stationary Sources (Instrumental Analyzer Procedure)**

* * * * *

*3.3 Calibration Gas* means the gas mixture containing $NO_X$ at a known concentration and produced and certified in accordance with "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 updates. The tests for analyzer calibration error, drift, and system bias require the use of calibration gas prepared according to this protocol. If a zero gas is used for the low-level gas, it must meet the requirements under the definition for "zero air material" in 40 CFR 72.2 in place of being prepared by the traceability protocol.

* * * * *

*3.4 Calibration Span* means the upper limit of the analyzer's calibration that is set by the choice of high-level calibration gas. No valid run average concentration may exceed the calibration span. To the extent practicable, the measured emissions should be between 20 to 100 percent of the selected calibration span. This may not be practicable in some cases of low-concentration measurements or testing for compliance with an emission limit when emissions are substantially less than the limit. In such cases, calibration spans that are practicable to achieving the data quality objectives without being excessively high should be chosen.

* * * * *

*3.9 Drift* means the difference between the pre- and post-run system bias (or system calibration error) checks at a specific calibration gas concentration level (*i.e.* low-, mid- or high-).

*3.12* * * * An MST subjects the analyzer to a range of line voltages and temperatures that reflect potential field conditions to demonstrate its stability following procedures similar to those provided in 40 CFR 53.23. Ambient-level analyzers are exempt from the MST requirements of Section 16.3.

* * *

* * * * *

*6.2.2 Particulate Filter.* An in-stack or out-of-stack filter. The filter must be made of material that is non-reactive to the gas being sampled. The filter media for out-of-stack filters must be included in the system bias test. The particulate filter requirement may be waived in applications where no significant particulate matter is expected (*e.g.*, for emission testing of a combustion turbine firing natural gas).

* * * * *

*6.2.6 Calibration Gas Manifold.* * * * In system calibration mode, the system should be able to flood the sampling probe and vent excess gas.

* * *

* * * * *

*6.2.8.2 Low Concentration Analyzer.* When an analyzer is routinely calibrated with a calibration span of 20 ppmv or less, the manufacturer's stability test (MST) is required. See Table 7E–5 for test parameters.

* * * * *

*7.1 Calibration Gas.* * * * If a zero gas is used for the low-level gas, it must meet the requirements under the definition for "zero air material" in 40 CFR 72.2.

* * *

*7.1.4 Converter Efficiency Gas. What reagents do I need for the converter efficiency test?* The converter efficiency gas is a manufacturer-certified gas with a concentration sufficient to show $NO_2$ conversion at the concentrations encountered in the source. A test gas concentration in the 40 to 60 ppm range is suggested, but other concentrations may be more appropriate to specific sources. For the test described in Section 8.2.4.1, $NO_2$ is required. For the alternative converter efficiency tests in Section 16.2, NO is required.

* * * * *

*7.2 Interference Check. What reagents do I need for the interference check?* Use the appropriate test gases listed in Table 7E–3 or others not listed that can potentially interfere (as indicated by the test facility type, instrument manufacturer, etc.) to conduct the interference check. These gases should be manufacturer certified but do not have to be prepared by the EPA traceability protocol.

* * * * *

*8.1.2 Determination of Stratification.* Perform a stratification test at each test site to determine the appropriate number of sample traverse points. If testing for multiple pollutants or diluents at the same site, a stratification test using only one pollutant or diluent satisfies this requirement. A stratification test is not required for small stacks that are less than 4 inches in diameter * * *

* * * * *

*8.2.1 Calibration Gas Verification.* * * * Obtain a certificate from the gas manufacturer documenting the quality of the gas. * * *

* * * * *

*8.2.4* $NO_2$ to NO Conversion Efficiency. Before or after each field test, you must conduct an $NO_2$ to NO conversion efficiency test if your system converts $NO_2$ to NO before analyzing for $NO_X$. You may risk testing multiple facilities before performing this test provided you pass this test at the conclusion of the final facility test. A failed final conversion efficiency test in this case will invalidate all tests performed subsequent to the test in which the converter efficiency test was passed. * * *

*8.2.4.1.* Introduce $NO_2$ converter efficiency gas to the analyzer in direct calibration mode and record the $NO_X$ concentration displayed by the analyzer. Calculate the converter efficiency using Equation 7E–7 in Section 12.7. The specification for converter efficiency in Section 13.5 must be met. The user is cautioned that state-of-the-art $NO_2$ calibration gases may have limited shelf lives, and this could affect the ability to pass the 90-percent conversion efficiency requirement.

*8.2.7 Interference Check.* * * *

(1) You may introduce the appropriate interference test gases (that are potentially encountered during a test, see examples in Table 7E–3) into the analyzer separately or as mixtures. Test the analyzer with the interference gas alone at the highest concentration expected at a test source and again with the interference gas and $NO_X$ at a representative $NO_X$ test concentration.

* * *

(2) * * * This interference test is valid for the life of the instrument unless major analytical components (*e.g.*, the detector) are replaced with different model parts. If major components are replaced with different model parts, the interference gas check must be repeated before returning the analyzer to service.

* * * * *

*8.4 Sample Collection.*

(1) Position the probe at the first sampling point. Purge the system for at least two times the response time before recording any data. Then, traverse all required sampling points, sampling at each point for an equal length of time and maintaining the appropriate sample flow rate or dilution ratio (as applicable). You must record at least

one valid data point per minute during the test run.

(2) Each time the probe is removed from the stack and replaced, you must recondition the sampling system for at least two times the system response time prior to your next recording. If the average of any run exceeds the calibration span value, that run is invalid.

* * * * *

*8.5 Post-Run System Bias Check and Drift Assessment.*

How do I confirm that each sample I collect is valid? After each run, repeat the system bias check or 2-point system calibration error check (for dilution systems) to validate the run. Do not make adjustments to the measurement system (other than to maintain the target sampling rate or dilution ratio) between the end of the run and the completion of the post-run system bias or system calibration error check. Note that for all post-run system bias or 2-point system calibration error checks, you may inject the low-level gas first and the upscale gas last, or vice-versa. You may risk sampling for multiple runs before performing the post-run bias or system calibration error check provided you pass this test at the conclusion of the group of runs. A failed final test in this case will invalidate all runs subsequent to the last passed test.

(1) If you do not pass the post-run system bias (or system calibration error) check, then the run is invalid. You must diagnose and fix the problem and pass another calibration error test (Section 8.2.3) and system bias (or 2-point system calibration error) check (Section 8.2.5) before repeating the run. Record the system bias (or system calibration error) results on a form similar to Table 7E–2.

* * * * *

*9.0 Quality Control*

SUMMARY TABLE OF QA/QC

| Status | Process or element | QA/QC specification | Acceptance criteria | Checking frequency |
|---|---|---|---|---|
| * | * | * | * | * |
| M ..... | System Performance ..... | $NO_2$–NO conversion efficiency. | ≥ 90% of certified test gas concentration ..... | Before or after each test. |
| * | * | * | * | * |

* * *

*10.0 Calibration and Standardization*

* * *

(1) * * * Analyzers that measure NO and $NO_2$ separately without using a converter must be calibrated with both NO and $NO_2$.

* * * * *

*12.1 Nomenclature.* * * *

$C_{native}$ = $NO_X$ concentration in the stack gas as calculated in Section 12.6, ppmv.

* * *

$C_O$ = Average of the initial and final system calibration bias (or 2-point system calibration error) check responses from the low-level (or zero) calibration gas, ppmv.

$C_{OA}$ = Actual concentration of the low-level calibration gas, ppmv.

* * *

DF = Dilution system dilution factor or spike gas dilution factor, dimensionless.

* * *

$SB_{final}$ = Post-run system bias, percent of calibration span.

* * * * *

*12.4 System Calibration Error.* Use Equation 7E–3 to calculate the system calibration error for dilution systems. Equation 7E–3 applies to both the initial 3-point system calibration error test and the subsequent 2-point calibration error checks between test runs. In this equation, the term "$C_s$" refers to the diluted calibration gas concentration measured by the analyzer.

$$SCE = \frac{(C_S \quad DF) - C_V}{CS} \times 100 \qquad \text{Eq. 7E-3}$$

* * * * *

*12.6 Effluent Gas Concentration.* For each test run, calculate $C_{avg}$, the arithmetic average of all valid $NO_X$ concentration values (*e.g.*, 1-minute averages). Then adjust the value of $C_{avg}$ for bias using Equation 7E–5a if you use a non-zero gas as your low-level calibration gas, or Equation 7E–5b if you use a zero gas as your low-level calibration gas.

$$C_{Gas} = \left(C_{Avg} - C_M\right)\frac{C_{MA} - C_{OA}}{C_M - C_O} + C_{MA} \qquad \text{Eq. 7E-5a}$$

$$C_{Gas} = \left(C_{Avg} - C_O\right)\frac{C_{MA}}{C_M - C_O} \qquad \text{Eq. 7E-5b}$$

* * * * *

*12.9 Alternative $NO_2$ Converter Efficiency.* If the alternative procedure of Section 16.2.2 is used, determine the $NO_X$ concentration decrease from $NO_{XPeak}$ after the minimum 30-minute test interval using Equation 7E–9. This decrease from $NO_{XPeak}$ must meet the

requirement in Section 13.5 for the converter to be acceptable.

$$\%\,Decrease = \frac{NO_{XPeak} - NO_{XFinal}}{NO_{XPeak}} \times 100 \qquad \text{Eq. 7E-9}$$

* * * * *

*12.11 Calculated Spike Gas Concentration and Spike Recovery for the Example Alternative Dynamic Spiking Procedure in Section 16.1.3.*

* * *

$$R = \frac{DF\ (C_{SS} - C_{native}) + C_{native}}{C_{spike}} \quad 100 \qquad \text{Eq. 7E-12}$$

* * * * *

*13.5 $NO_2$ to NO Conversion Efficiency Test (as applicable).* The $NO_2$ to NO conversion efficiency, calculated according to Equation 7E–7, must be greater than or equal to 90 percent. The alternative conversion efficiency check, described in Section 16.2.2 and calculated according to Equation 7E–9, must not result in a decrease from $NO_{XPcak}$ by more than 2.0 percent.

* * * * *

*16.2.2 Tedlar Bag Procedure.* * * * Fill the remainder of the bag with mid- to high-level NO in nitrogen (or other appropriate concentration) calibration gas.

* * * * *

*16.3 Manufacturer's Stability Test.* A manufacturer's stability test is required for all analyzers that routinely measure emissions below 20 ppmv and is optional but recommended for other analyzers. This test evaluates each analyzer model by subjecting it to the tests listed in Table 7E–5 following procedures similar to those in 40 CFR 53.23 for thermal stability and insensitivity to supply voltage variations. If the analyzer will be used under temperature conditions that are outside the test conditions in Table B–4 of Part 53.23, alternative test temperatures that better reflect the analyzer field environment should be used. Alternative procedures or documentation that establish the analyzer's stability over the appropriate line voltages and temperatures are acceptable.

* * * * *

TABLE 7E–3.—EXAMPLE INTERFERENCE CHECK GAS CONCENTRATIONS

| Potential interferent gas[1] | Concentrations[2] sample conditioning type | |
|---|---|---|
| | Hot wet | Dried |
| $CO_2$ | 5 and 15% | 5 and 15% |
| $H_2O$ | 25% | 1% |
| NO | 15 ppmv | 15 ppmv |
| $NO_2$ | 15 ppmv | 15 ppmv |
| $N_2O$ | 10 ppmv | 10 ppmv |
| CO | 50 ppmv | 50 ppmv |
| $NH_3$ | 10 ppmv | 10 ppmv |
| $CH_4$ | 50 ppmv | 50 ppmv |
| $SO_2$ | 20 ppmv | 20 ppmv |
| $H_2$ | 50 ppmv | 50 ppmv |
| HCl | 10 ppmv | 10 ppmv |

(1) Any applicable gas may be eliminated or tested at a reduced level if the manufacturer has provided reliable means for limiting or scrubbing that gas to a specified level.

(2) As practicable, gas concentrations should be the highest expected at test sites.

* * * * *

TABLE 7E–5.—MANUFACTURER STABILITY TEST

| Test description | Acceptance criteria (note 1) |
|---|---|
| Thermal Stability | Temperature range when drift does not exceed 3.0% of analyzer range over a 12-hour run when measured with $NO_X$ present @ 80% of calibration span. |
| Fault Conditions | Identify conditions which, when they occur, result in performance which is not in compliance with the Manufacturer's Stability Test criteria. These are to be indicated visually or electrically to alert the operator of the problem. |
| Insensitivity to Supply Voltage Variations | ± 10.0% (or manufacturers alternative) variation from nominal voltage must produce a drift of ≤ 2.0% of calibration span for either zero or concentration ≥ 80% $NO_X$ present. |
| Analyzer Calibration Error | For a low-, medium-, and high-calibration gas, the difference between the manufacturer certified value and the analyzer response in direct calibration mode, no more than 2.0% of calibration span. |

**Note 1:** If the instrument is to be used as a Low Range analyzer, all tests must be performed at a calibration span of 20 ppm or less.

* * * * *

**Appendix A–7—[Amended]**

■ 5. Amend Method 20 by adding a sentence to the end of Section 8.4 to read as follows:

**Method 20—Determination of Oxygen and Carbon Dioxide Concentrations in Emissions From Stationary Sources (Instrumental Analyzer Procedure)**

* * * * *

*8.4 Sample Collection.* * * * A test run must have a duration of at least 21 minutes.

* * * * *

[FR Doc. E8–11398 Filed 5–21–08; 8:45 am]

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Part III

# Environmental Protection Agency

40 CFR Parts 60 and 63
Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry; Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries; Final Rule

## ENVIRONMENTAL PROTECTION AGENCY

### 40 CFR Parts 60 and 63

**[EPA–HQ–OAR–2006–0699; FRL–8492–4]**

**RIN 2060–AN71**

# Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry; Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries

**AGENCY:** Environmental Protection Agency (EPA).

**ACTION:** Final rule.

**SUMMARY:** EPA is issuing final amendments to the standards of performance for equipment leaks of volatile organic compounds in the synthetic organic chemicals manufacturing industry and to the standards of performance for equipment leaks of volatile organic compounds in petroleum refineries. The amended standards for the synthetic organic chemicals manufacturing industry apply to affected facilities that are constructed, reconstructed, or modified after January 5, 1981, and on or before November 7, 2006. The amended standards for petroleum refineries apply to affected facilities that are constructed, reconstructed, or modified after January 4, 1983, and on or before November 7, 2006. In this action, EPA is also issuing new standards of performance for equipment leaks of volatile organic compounds in the synthetic organic chemicals manufacturing industry and for equipment leaks of volatile organic compounds in petroleum refineries which apply to affected facilities that are constructed, reconstructed, or modified after November 7, 2006. The final amendments and new standards are based on the results of our review of the existing regulations as required by section 111(b)(1)(B) of the Clean Air Act.

**DATES:** This final rule is effective on November 16, 2007. The incorporation by reference of certain publications listed in these rules is approved by the Director of the Federal Register as of November 16, 2007.

**ADDRESSES:** EPA has established a docket for this action under Docket ID No. EPA–HQ–OAR–2006–0699. All documents in the docket are listed in the Federal Docket Management System index at *www.regulations.gov*. 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 through *www.regulations.gov* or in hard copy at the Air and Radiation 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 and Radiation Docket is (202) 566–1742.

**FOR FURTHER INFORMATION CONTACT:** For information concerning the final amendments and new standards, contact Ms. Karen Rackley, Coatings and Chemicals Group, Sector Policies and Programs Division, Office of Air Quality Planning and Standards (E143–01), Environmental Protection Agency, Research Triangle Park, North Carolina 27711; telephone number: (919) 541–0634; fax number: (919) 541–0246; e-mail address: *rackley.karen@epa.gov*. For information concerning compliance and enforcement of the final amendments and new standards, contact Ms. Marcia Mia, Air Compliance Branch, Compliance Assessment and Media Programs Division, Office of Compliance (MC 2223A), Environmental Protection Agency, Washington, DC 20460; telephone number: (202) 564–7042; fax number: (202) 564–0050; and e-mail address: *mia.marcia@epa.gov*.

**SUPPLEMENTARY INFORMATION:**

*Regulated Entities.* Categories and entities potentially regulated by this action include:

| Category | NAICS code[1] | Examples of potentially regulated entities |
|---|---|---|
| Industry | 324110<br>Primarily 325110, 325192, 325193, and 325199. | Petroleum refiners.<br>Synthetic organic chemical manufacturing industry (SOCMI) units, e.g., producers of benzene, toluene, or any other chemical listed in 40 CFR 60.489. |

[1] North American Industrial Classification Code.

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 is regulated by this action, you should examine the applicability criteria in 40 CFR 60.480, 60.590, 60.480a, and 60.590a. If you have any questions regarding the applicability of the final amendments or new standards to a particular entity, contact the people listed in the preceding **FOR FURTHER INFORMATION CONTACT** section.

*Worldwide Web (WWW).* In addition to being available in the docket, an electronic copy of the final rule is available on the WWW through the Technology Transfer Network (TTN). Following signature, EPA will post a copy of the final rule 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.

*Judicial Review.* Under section 307(b) of the Clean Air Act (CAA), judicial review of the 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 January 15, 2008. Under section 307(d)(7)(B) of the CAA, only an objection to the final rule that was raised with reasonable specificity during the period for pubic 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 is 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.

*Outline.* The information presented in this preamble is organized as follows:



## I. Background Information

### *A. What is the statutory authority for the final amendments and new standards?*

New source performance standards (NSPS) implement CAA section 111 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 are to attain and maintain ambient air quality by ensuring that the best demonstrated emission control technologies are installed as the industrial infrastructure is modernized. Since 1970, the NSPS have been successful in achieving long-term emissions reductions at numerous industries by assuring cost-effective controls are installed on new, reconstructed, or modified sources.

Section 111 of the CAA requires that NSPS reflect the application of the best system of emission reductions which (taking into consideration the cost of achieving such emission reductions, any non-air quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated. This level of control is commonly referred to as best demonstrated technology (BDT).

Section 111(b)(1)(B) of the CAA requires that EPA periodically review and revise the standards of performance, as necessary, to reflect improvements in methods for reducing emissions. Based on the results of the review required by CAA section 111(b)(1)(B), we proposed amendments to the NSPS for equipment leaks of volatile organic compounds (VOC) in the synthetic organic chemicals manufacturing industry (SOCMI) and the petroleum refining industry on November 7, 2006 (71 FR 65302). In this action, EPA is finalizing amendments to 40 CFR part 60, subparts VV and GGG and issuing new standards of performance in 40 CFR part 60, subparts VVa and GGGa.

### *B. What are the current equipment leak NSPS?*

New source performance standards for equipment leaks of VOC have been developed for four source categories. Subpart VV of 40 CFR part 60 applies to SOCMI process units. Subpart DDD of 40 CFR part 60, Standards of Performance for Volatile Organic Compound (VOC) Emissions from the Polymer Manufacturing Industry, applies to polypropylene, polyethylene, polystyrene, and poly (ethylene terephthalate) process units. Subpart GGG of 40 CFR part 60 applies to petroleum refining process units. Subpart KKK of 40 CFR part 60 applies to onshore natural gas processing plants. Subparts DDD, GGG, and KKK of 40 CFR part 60 cross-reference the requirements in subpart VV, and they specify source category-specific definitions and exceptions to the requirements in subpart VV.

The NSPS for equipment leaks of VOC in the SOCMI (40 CFR part 60, subpart VV) were originally promulgated on October 18, 1983 (48 FR 48335) and apply to all equipment, as defined by the rule, within a process unit in the SOCMI that commenced construction, reconstruction, or modification after January 5, 1981. For the purpose of subpart VV, the SOCMI consists of process units producing any of the chemicals listed in 40 CFR 60.489 of subpart VV. The standards apply to pumps, compressors, pressure relief devices, sampling connection systems, open-ended valves or lines (OEL), valves, and flanges or other connectors in VOC service. Depending on the type of equipment, the standards require either periodic monitoring for and repair of leaks, the use of specified equipment to minimize leaks, or specified work practices. Monitoring for leaks must be conducted using EPA Method 21 in appendix A–7 to 40 CFR part 60 or other approved equivalent monitoring techniques. Owners and operators must keep records that identify the equipment that is subject to the standards, identify equipment that is leaking, and document attempts at repair. Information related to leaks and repair attempts also must be included in semiannual reports. This subpart has been amended several times between 1984 and 2000. Typically, these amendments added definitions, exemptions, alternative compliance options, and clarifications. For example, one amendment provides an option to comply with the equipment leak provisions in the Consolidated Federal Air Rule (CAR) (40 CFR part 65, subpart F). None of these amendments increased the intended performance level of the standards.

The NSPS for equipment leaks of VOC in petroleum refineries (40 CFR part 60, subpart GGG) apply to petroleum refining process units for which construction, reconstruction, or modification commenced after January

4, 1983. Those standards were originally promulgated on May 30, 1984 (49 FR 22606), and have been amended only once since the original promulgation (65 FR 61768, October 17, 2000) to update the American Society for Testing and Materials (ASTM) test method references.

*C. How were the final amendments developed?*

We proposed amendments to 40 CFR part 60, subpart VV and 40 CFR part 60, subpart GGG on November 7, 2006 (71 FR 65302). The preamble for the proposed amendments described the rationale for the proposed amendments. Public comments were solicited at the time of proposal. The public comment period lasted from November 7, 2006, to February 8, 2007. We offered at proposal the opportunity for a public hearing concerning the proposed amendments, but no hearing was requested. We also published a Notice of Additional Data Availability (NODA) on July 9, 2007 (72 FR 37157). The NODA provided additional information regarding OEL. Public comments were solicited at the time of publication, and the public comment period lasted from July 9, 2007, to August 8, 2007.

We received a total of 28 public comment letters during the comment periods, 23 on the proposed amendments and five on the NODA. Comments were submitted by industry trade associations and consultants, chemical companies and petroleum refineries, state regulatory agencies, local government agencies, and environmental groups. These final amendments reflect our consideration of all of the comments received during the comment periods. Major public comments on the proposed amendments, along with our responses to those comments, are summarized in this preamble.

## II. Summary of the Final Amendments, New Standards, and Changes Since Proposal

In response to public comments, we have revised the scope and applicability of the proposed amendments to the standards of performance for equipment leaks of VOC for SOCMI (40 CFR part 60, subpart VV) and petroleum refineries (40 CFR part 60, subpart GGG). As proposed, all of the amendments to subparts VV and GGG, except the change in leak definitions for pumps and valves, applied to affected facilities in these industries that commenced construction, reconstruction, or modification after January 5, 1981, (SOCMI) or January 4, 1983, (petroleum refineries). In addition, all of the proposed amendments, except the leak definition change, applied to affected facilities under all other NSPS that cross-reference subpart VV (i.e., 40 CFR part 60, subparts DDD and KKK).

Based on the public comments, we decided to include only clarifications, changes that reduce burden, and additional compliance options in the final amendments to 40 CFR part 60, subparts VV and GGG. The final amendments to both subparts also limit which SOCMI and petroleum refinery affected sources are subject to the existing subparts. Specifically, the existing subparts only apply to those existing affected sources that commenced construction, reconstruction, or modification after January 5, 1981, (SOCMI) or January 4, 1983, (petroleum refineries) and on or before November 7, 2006. The final amendments to subpart VV also apply to affected sources under NSPS that cross-reference subpart VV (i.e., 40 CFR part 60, subparts DDD and KKK).

In addition to amending 40 CFR part 60, subparts VV and GGG, we also decided to develop new standards in new subparts VVa and GGGa of 40 CFR part 60 that apply only to SOCMI and petroleum refinery affected sources, respectively, that commence construction, reconstruction, or modification after November 7, 2006. These new standards parallel the standards in the amended subparts VV and GGG, but they also include different standards for pumps in light liquid service and valves in gas/vapor or light liquid service (i.e., lower leak definitions than in subparts VV and GGG), and they include additional recordkeeping and instrument calibration requirements. Furthermore, the new standards in 40 CFR part 60, subpart VVa include monitoring and repair requirements for connectors. The new standards do not apply to affected sources under 40 CFR part 60, subparts DDD or KKK because we have not amended those subparts to reference the requirements in subpart VVa and we have not completed an analysis to determine if the new standards are BDT for subparts DDD and KKK.

*A. What are the final amendments to 40 CFR part 60, subpart VV?*

The final amendments to 40 CFR part 60, subpart VV provide additional compliance options, clarify ambiguous provisions, and make technical corrections. These changes are summarized in Table 1 in section III.C of this preamble.

1. Applicability

The owner or operator of an affected facility subject to 40 CFR part 60, subpart VV may choose to comply with the requirements in new 40 CFR part 60, subpart VVa instead of the requirements in subpart VV.

2. Standards

The final amendments simplify the compliance requirements for pumps. When indications of liquids dripping are observed during weekly inspections, 40 CFR part 60, subpart VV requires repair of the leak following the same procedures as if the leak were detected by monitoring. The final amendment in 40 CFR 60.482–2(b)(2) allows the owner or operator to either repair the leak by eliminating the indications of liquids dripping or determine if it is leaking based on the instrument reading obtained by monitoring the pump in accordance with EPA Method 21 (40 CFR part 60, appendix A–7) or other approved equivalent monitoring techniques. This amendment will focus the leak detection and repair (LDAR) program on finding and repairing VOC leaks.

The final amendments also include an alternative compliance option that allows less frequent monitoring for pumps and valves in batch process units that operate part-time during the year. This alternative applies to currently required monthly, quarterly, and semiannual monitoring intervals; less frequent monitoring is not allowed for monitoring that is currently required on an annual or less frequent basis. For example, pumps in a process unit that operate 5,250 hours per year (about 60 percent of full-time operation) may be monitored every other month rather than monthly. This alternative will ensure that monitoring occurs consistently while the process unit is operating. The alternative monitoring schedule for batch processes was developed as part of the development of the hazardous organic national emission standards for hazardous air pollutants (NESHAP) (HON) (57 FR 62680). This alternative has been determined to be comparable to the provisions for continuous processes. As the time in use increases, the monitoring frequencies are identical for both batch and continuous processes.

In response to public comments, we have revised the proposed clarification to the initial monitoring requirements for pumps and valves (that all pumps and valves be monitored within the first month of operation after installation). The final amendments require the owner or operator to monitor all pumps

on a monthly basis regardless of whether the pump is new or existing. The owner or operator of a new valve must monitor the valve for the first time within 30 days after being placed into service to ensure proper installation. Any valve for which a leak is not detected for 2 successive months may be monitored the first month of every quarter, beginning with the next quarter, until a leak is detected. As an alternative to monitoring a new valve within 30 days, if the valves in the process unit are monitored under the alternative standards for valves that allow skip period leak detection and repair in 40 CFR 60.483–2, the owner or operator must count the new valve as leaking when calculating the percentage of valves leaking. If less than 2.0 percent of the valves are leaking for that process unit, the valve must be monitored for the first time during the next scheduled monitoring event for existing valves in the process unit or within 90 days, whichever comes first.

As an alternative to monitoring all of the valves in the first month of a quarter, an owner or operator may elect to subdivide the process unit into two or three subgroups of valves and monitor each subgroup in a different month during the quarter, provided each subgroup is monitored every 3 months. The owner or operator must keep records of the valves assigned to each subgroup.

The clarifications to the requirements for sampling connection systems in 40 CFR 60.482–5 have been revised since proposal to add additional destinations for purged process fluid. All containers must be covered when not being filled or emptied. The amendments also clarify what materials must be captured and returned to the process during sampling.

In response to comments, we have revised the proposed option for delay of repair in 40 CFR 60.482–9. The proposed amendment would have allowed the owner or operator to discontinue monitoring for equipment on delay-of-repair. We have not included this in the final amendments and new standards because a leak may worsen while on delay-of-repair and require a more immediate shutdown. Therefore, all equipment on delay-of-repair must be monitored as scheduled. The option to consider equipment to be repaired if two consecutive readings are below the leak definition was not removed. If two consecutive readings are below the applicable leak definition, the owner or operator may remove the equipment from delay-of-repair.

3. Definitions

Several amendments clarify the original intent of the definitions in 40 CFR part 60, subpart VV. These definitions include "connector," "process unit," and "sampling connection system." In addition, definitions of "closed-loop system," "closed-purge system," "storage vessel," and "transfer rack" were added to further clarify existing definitions. The definition of "process unit" is discussed in further detail in section IV.A.3 of this preamble. The rationale for revising and adding the other definitions is included in Docket ID No. EPA–HQ–OAR–2006–0699.

4. Miscellaneous Corrections

Finally, the final amendments include a few technical corrections to fix references and other miscellaneous errors in 40 CFR part 60, subpart VV. No changes have been made to the proposed corrections, and a number of additional corrections are included in the final amendments. The technical corrections are identified in section III.A.3 of the preamble to the proposed amendments (71 FR 65307–65308, November 7, 2006) as well as Table 1 of this preamble.

*B. What are the final amendments to 40 CFR part 60, subpart GGG?*

A few minor changes have been made to the 40 CFR part 60, subpart GGG amendments since proposal. The heading and 40 CFR 60.590(b) were revised to clarify that the subpart applies to sources that commence construction, reconstruction, or modification on or before November 7, 2006, and 40 CFR 60.590(d) was revised to exclude facilities subject to 40 CFR part 60, subpart VVa. Proposed revisions that remain in the final amendments to subpart GGG include a definition of "asphalt" and an exemption from the requirements for OEL in 40 CFR 60.482–6(a) through (c) for OEL containing asphalt. The definition of "process unit" is comparable to the definition in 40 CFR part 60, subpart VV.

The final amendments also include a few technical corrections to fix references and other miscellaneous errors in 40 CFR part 60, subpart GGG. These changes are identified in section III.B.5 of the preamble to the proposed amendments (71 FR 65309, November 7, 2006). No changes have been made to these corrections since proposal.

*C. What are the requirements of 40 CFR part 60, subpart VVa?*

40 CFR part 60, subpart VVa applies to affected facilities in the SOCMI that are constructed, reconstructed, or modified after November 7, 2006. This new subpart includes all the requirements of 40 CFR part 60, subpart VV, as amended, along with new provisions. The owner or operator of an affected facility subject to subpart VVa may elect to comply with the CAR at 40 CFR part 65, subpart F, or the HON at 40 CFR part 63, subpart H, instead of the requirements in subpart VVa, provided they still comply with the requirements in 40 CFR 60.482–6a.

40 CFR part 60, subpart VVa includes lower leak definitions for pumps and valves than 40 CFR part 60, subpart VV. Under subpart VVa, the leak definition for pumps in light liquid service is 2,000 parts per million (ppm) (5,000 ppm for pumps handling polymerizing monomers) instead of 10,000 ppm. The leak definition for valves in gas/vapor service or light liquid service is 500 ppm instead of 10,000 ppm. Rationale for this new standard was provided in section III.A.1 of the preamble to the proposed amendments and is discussed further in section III.A.1 of this preamble.

40 CFR part 60, subpart VVa also includes requirements for monitoring connectors. The owner or operator is required to monitor connectors at a leak definition of 500 ppm and at a frequency that is based on the percentage of connectors found to be leaking. The rationale supporting the LDAR provisions for connectors is located in section III.A.2 of this preamble.

40 CFR part 60, subpart VVa includes additional recordkeeping requirements and quality assurance measures. Records must identify the monitoring instrument, operator, equipment, the date, and maximum instrument reading. A calibration drift assessment is required at the end of each day of monitoring and records of monitoring instrument calibrations are required. The calibration drift assessment requirements proposed for 40 CFR part 60, subpart VV were revised based on public comments. The requirements in the new standards include a requirement to remonitor equipment if the drift assessment shows positive drift. The requirements in the new standards provide for a less stringent remonitoring effort for drift assessments showing negative drift.

*D. What are the requirements of 40 CFR part 60, subpart GGGa?*

40 CFR part 60, subpart GGGa applies to affected facilities at petroleum refineries that are constructed, reconstructed, or modified after November 7, 2006. New subpart GGGa

includes the requirements in 40 CFR part 60, subpart GGG, as amended. Affected facilities must comply with the requirements in new subpart VVa of 40 CFR part 60, except for the monitoring requirements applicable to connectors.

## III. Rationale for Changes Since Proposal

### *A. How did EPA develop new standards for 40 CFR part 60, subparts VVa and GGGa?*

Five sources of information were considered in reviewing the appropriateness of the current NSPS requirements for new sources: (1) Applicable Federal regulations; (2) applicable state and local regulations; (3) data from National Enforcement Investigations Center (NEIC) inspections; (4) emissions data provided by industry representatives; and (5) petroleum refinery consent decrees. (A significant number of refineries, representing about 77 percent of the national refining capacity, are subject to consent decrees that limit the emissions from 40 CFR part 60, subpart GGG process units.) Once we identified leak definitions for various equipment types, we evaluated these leak definitions in conjunction with technical feasibility, costs, and emission reductions to determine BDT for each type of equipment.

The cost methodology incorporates the calculation of annualized costs and emission reductions associated with each of the options presented. Cost-effectiveness is the annualized cost of control divided by the annual emission reductions achieved. For NSPS regulations, the standard metric for expressing costs and emission reductions is the impact on all affected facilities accumulated over the first 5 years of the regulation. Details of the calculations can be found in the public docket (EPA–OAR–HQ–2006–0699). Our BDT determinations took all relevant factors into account, including cost considerations.

For each of the new standards, the predominant method used to reduce emissions from equipment leaks is the work practice of an LDAR program that includes periodic monitoring of equipment using EPA Method 21. This method has been used for more than 20 years to detect leaks and is currently the most widely-used test method. However, other approved methods may be used to detect leaks.

We also considered an equipment standard requiring installation of "leakless" equipment. "Leakless" equipment, such as diaphragm valves, is less likely to leak than standard equipment, but leaks may still develop. Therefore, monitoring or other type of observation is appropriate to ensure that leaks are caught if they develop. In addition, these types of equipment may not be suitable for all possible process operating temperatures, pressures, and fluid types. We could not identify any new "leakless" technologies that could be applied in all applications. Therefore, requiring "leakless" equipment is not technically feasible and this option was not considered to be BDT for SOCMI or petroleum refining sources. We note that 40 CFR part 60, subpart VV does include provisions for equipment designed for no detectable emissions, so owners or operators that do replace existing equipment with "leakless" equipment have options for compliance.

#### 1. Leak Definitions for Pumps and Valves

We previously demonstrated that leak definitions of 2,000 ppm for pumps and 500 ppm for valves are BDT in the preamble to the proposed amendments to 40 CFR part 60, subparts VV and GGG (November 7, 2006, 71 FR 65305, with additional discussion at 71 FR 65308). Since proposal, the cost-effectiveness values for this new requirement have changed slightly based on changes to the assumptions used to develop emission estimates; section V of this preamble includes details on the specific changes. For SOCMI, the estimated emission reductions are 94 tons of VOC per year at a cost savings of $380/ton. For petroleum refineries, the estimated emission reductions are 13 tons of VOC per year at a cost of $1,600/ton. The cost to achieve these emission reductions is still considered to be reasonable; therefore, we maintain our original conclusion that EPA Method 21 monitoring of pumps and valves and repair of leaks above 2,000 ppm for pumps and 500 ppm for valves is BDT.

We have also evaluated the cost-effectiveness of lowering the leak definitions even further for valves because there are some state rules and petroleum refinery consent decrees at lower levels. The results of that analysis show that an LDAR program for valves at a leak definition lower than 500 ppm is not cost-effective. The analysis shows emission reductions of 26 tons of additional VOC per year at a cost-effectiveness of $5,700/ton for SOCMI and emission reductions of 8 tons of additional VOC per year at a cost-effectiveness of $16,000/ton for refineries. The additional VOC emission reductions at a leak definition lower than 500 ppm is not cost-effective. The results of the impacts analysis is provided in the docket (Docket ID No. EPA–HQ–OAR–2006–0699).

We decided not to consider a lower leak definition for pumps because we do not have evidence that it will achieve significant emission reductions at reasonable cost and because such a requirement would impose an unwarranted increase in the compliance burden. No other Federal or state rules require repair of pumps with leaks below 2,000 ppm, and concerns have been expressed in the past that repair of pumps with lower concentrations could result in significant and costly maintenance. We also cannot estimate the emission reductions because we are unsure how effective repairs will be for pumps with low leak concentrations. In addition, many facilities that will be subject to the new standards have other process units that are subject to other standards. Including a leak definition in the new standards that differs from the leak definitions in all other rules would make compliance more challenging at such facilities and unnecessarily increase the potential for inadvertent errors.

We also did not consider increasing the number of times per year that valves and pumps must be monitored. Valves and pumps are already subject to monthly monitoring. The cost to monitor more frequently would outweigh the possible emission reductions. Additionally, pumps are subject to weekly inspections for indications of liquids dripping. Therefore, the monitoring frequency was not changed and is still considered BDT.

#### 2. Other New Standards in 40 CFR Part 60, Subpart VVa

*Connector Monitoring.* The current NSPS in 40 CFR part 60, subpart VV limits VOC emissions from connectors by specifying that if a potential leak is found by visual, audible, olfactory, or any other detection method, the owner or operator must eliminate the indications of the potential leak or monitor the connector to determine whether the potential leak is leaking VOC greater than 10,000 ppm. If the potential leak is actually a leak, it must be repaired. When the current NSPS were promulgated, we concluded that this procedure would reduce emissions by correcting major leaks.

After consideration of current operating practices, we concluded that repairing connector leaks as they are discovered is still the predominant method for reduction of VOC from connectors. However, during our review of the current requirements, we found a

number of Federal and state regulations that require additional efforts to reduce emissions, including regular monitoring and repair. Therefore, we evaluated options to achieve further emission reductions from connectors. Federal rules in which connector monitoring and repair of leaks above 500 ppm is required include the National Emission Standards for Organic Hazardous Air Pollutants for Equipment Leaks (HON) in 40 CFR part 63, subpart H, the National Emission Standards for Equipment Leaks—Control Level 2 Standards (Generic MACT) in 40 CFR part 63, subpart UU, the National Emission Standards for Hazardous Air Pollutants for Source Categories: Generic Maximum Achievable Control Technology Standards (Ethylene NESHAP) in 40 CFR part 63, subpart YY, and the CAR. The National Emission Standards for Hazardous Air Pollutants: Miscellaneous Organic Chemical Manufacturing (MON) in 40 CFR part 63, subpart FFFF also includes connector monitoring and repair of leaks above 500 ppm for new sources. In addition, the National Emission Standards for Hazardous Air Pollutants From Petroleum Refineries (Refinery NESHAP) in 40 CFR part 63, subpart CC provides a higher maximum value for percent of leaking valves under which an owner or operator may use the skip period provisions if connector monitoring is included in the LDAR program. Based on this information, we felt that additional VOC control could be achieved by requiring connector monitoring and repair, but we needed additional information to determine whether connector monitoring is BDT. As a result, we requested comment on whether we should require periodic monitoring and repair of connectors to ensure that any leaks are corrected more quickly.

Upon consideration and review of the public comments, we evaluated whether the connector monitoring and repair provisions included in the Generic MACT are BDT for 40 CFR part 60, subparts VVa and GGGa. The Generic MACT provisions include a leak definition of 500 ppm and a monitoring frequency based on the number of connectors found to be leaking during the initial monitoring campaign.

For SOCMI, the estimated emission reductions achieved by connector monitoring and repair of leaks above 500 ppm are 230 tons of VOC per year at a cost of $2,500/ton. For petroleum refineries, the estimated emission reductions are 92 tons of VOC per year at a cost of $20,000/ton. The cost to achieve these emission reductions is considered to be reasonable for SOCMI sources but is not reasonable for petroleum refineries. Based on these impacts and consideration of current operating practices, we concluded that BDT for connectors at SOCMI sources is monitoring using EPA Method 21 or another approved alternative method at a frequency based on the number of connectors found leaking during initial monitoring and repair of leaks above 500 ppm. We concluded that BDT for connectors at petroleum refineries is equivalent to the current 40 CFR part 60, subpart GGG requirements. Therefore, we are promulgating connector monitoring and repair standards consistent with this determination for SOCMI sources subject to 40 CFR part 60, subpart VVa that will not apply to petroleum refinery sources subject to 40 CFR part 60, subpart GGGa.

*B. How did EPA develop the new compliance requirements in 40 CFR part 60, subparts VVa and GGGa?*

The recordkeeping requirements in the final amendments and new standards are authorized by section 114 of the CAA. Section 114 of the CAA allows EPA to require one-time, periodic, or continuous records for the purpose of determining if the owner or operator is in compliance with the standard. The recordkeeping requirements in the final amendments are the minimum necessary for affected facilities to demonstrate compliance and for EPA to enforce the rule. The recordkeeping requirements in the new standards include a few requirements in addition to the requirements in the final amendments. Most of these requirements are associated with new monitoring and repair requirements; other additional requirements are minimal and are necessary for EPA to enforce the rule. Further rationale for the new requirements is available below and in section IV.D of this preamble.

We have made significant changes to the proposed recordkeeping requirements as a result of the changes made to the scope and applicability of the standards. Because the final amendments to 40 CFR part 60, subparts VV and GGG include only clarifications to existing requirements, burden reducing provisions, and new compliance options, no changes or additions to the recordkeeping requirements in subpart VV or GGG are needed to document and/or enforce these amendments.

Sources subject to the new standards in 40 CFR part 60, subpart VVa are required to keep records of the same information required by 40 CFR part 60, subpart VV and certain additional information described below. Sources subject to 40 CFR part 60, subpart GGGa must comply with the requirements in subpart VVa except for the monitoring requirements applicable to connectors (and the associated recordkeeping requirements). Facilities subject to 40 CFR part 60, subparts DDD, GGG, or KKK are excluded from the requirement to comply with the recordkeeping provisions of subpart VVa because these subparts are not being amended to reference the new standards in subpart VVa.

The new recordkeeping provisions in 40 CFR part 60, subpart VVa require general identifying information for each monitoring activity required by the rule. As explained in the preamble to the proposed amendments (71 FR 65308, November 7, 2006), many facilities already record this information. This information requirement is consistent with other equipment leak standards and is needed by enforcement representatives to determine if the facility is complying with the standards. Specifically, EPA found that the results of the LDAR review demonstrated that the current requirements are not sufficient to verify that all monitoring requirements have been performed. For example, EPA enforcement initiatives have found missed monitoring (monitoring at an inappropriate interval, monitoring late, or not monitoring), understated leak rates, leaks not found or repaired, and monitoring records indicating that more equipment was monitored than physically possible given the time needed to meet EPA Method 21 requirements, among other issues. Since we cannot physically inspect every facility on the schedule required by the LDAR program, these additional records will provide safeguards that the program is being implemented as intended.

Other new recordkeeping requirements include specific information that is necessary to demonstrate compliance with the new monitoring provisions for connectors and pumps in light liquid service (weekly visual inspections for indications of dripping liquids). Records are also required to demonstrate compliance with the requirement for a calibration drift assessment at the end of each day and comparison of the results of the assessment with the most recent calibration results. We eliminated the proposed requirement to keep records of information on bypass lines because the new subpart does not include the requirement to monitor bypass lines. In addition, records of information related to the proposed initial monitoring requirement for pumps and valves

added to a process unit are not required because this monitoring requirement was revised since proposal, making additional records unnecessary.

We have reviewed the recordkeeping requirements and believe that these are the minimum needed to ensure compliance and that the requirements do not impose excessive costs. The costs of the recordkeeping requirements for 40 CFR part 60, subpart VVa, including the time required to enter and store additional information, are included in the information collection request (ICR) (see section V.B of this preamble).

*C. How did EPA develop the final amendments to 40 CFR part 60, subparts VV and GGG?*

The amendments to 40 CFR part 60, subpart VV are listed in Table 1 of this preamble. Most of the technical corrections for 40 CFR part 60, subparts VV and GGG were discussed in the preamble to the proposed amendments (71 FR 65302, November 7, 2006). Other technical corrections and amendments are the result of public comments, and these are discussed in detail in the responses to the applicable comments. For each amendment that is more significant than an editorial or grammatical correction, Table 1 to this preamble includes a reference to the rule language and a reference to the location of the detailed explanation.

TABLE 1.—SUMMARY OF FINAL AMENDMENTS TO 40 CFR PART 60, SUBPART VV AND RATIONALE FOR CLARIFICATIONS, ADDITIONAL COMPLIANCE OPTIONS, AND TECHNICAL CORRECTIONS

| Citation | Explanation or location of explanation[1] | Amendment |
|---|---|---|
| Heading | | Revised to clarify applicability of subpart. |
| 60.480(b) | | Revised to identify applicability to affected facilities that were constructed, reconstructed, or modified after January 5, 1981 and on or before November 7, 2006. |
| 60.480(d)(2) | | Clarified that design capacity refers to a chemical listed in 40 CFR 60.489. |
| 60.480(d)(2)–(5) | | Revised reference to nonexistent 40 CFR 60.482 to refer to 40 CFR 60.482–1 through 60.482–10. |
| 60.480(e)(1) | | Renumbered paragraph (e)(1) as (e)(1)(i) and paragraph (e)(2) as (e)(1)(ii); changed reference to paragraph (e)(2) to (e)(1)(ii). |
| 60.480(e)(2) | | Added paragraph that allows owners or operators to comply with 40 CFR part 60, subpart VVa as an alternative to 40 CFR part 60, subpart VV. |
| 60.481 | 71 FR 65308, column 3 | Corrected editorial errors in definition of "Capital expenditures." |
| 60.481 | 71 FR 65307, column 2 and section 5.4.3 of RTC. | Added new definition for "Closed-loop system." |
| 60.481 | 71 FR 65307, column 2 and section 5.4.3 of RTC. | Added new definition for "Closed-purge system." |
| 60.481 | Section 5.3.2 of RTC | Revised definition of "Connector." |
| 60.481 | Added missing word "the" before the word "atmosphere" and removed the word "rapid". | Revised definition of "First attempt at repair." |
| 60.481 | 71 FR 65308, column 3 and updated the mailing address for ASME. | Revised definition of "Hard piping." |
| 60.481 | Section IV.A.2 of this preamble | Revised definition of "Process unit." |
| 60.481 | Section 5.9.3 of RTC | Revised definition of "Process unit shutdown." |
| 60.481 | 71 FR 65308, column 1 | Revised definition of "Repaired." |
| 60.481 | Section 3.2.1 of RTC | Added new definition for "Storage vessel." |
| 60.481 | 71 FR 65307, column 3 | Added new definition for "Transfer rack." |
| 60.482–1(e) | Section 3.3 of RTC | Added paragraph (e) to address equipment in service less than 300 hours per year. |
| 60.482–1(f) | 71 FR 65304, column 3 and sections 5.6.1 and 5.6.2 of RTC. | Added paragraph (f) that allows less frequent monitoring of pumps and valves on batch process units that operate less than 365 days per year. |
| 60.482–1(g) | Section IV.A.2 of this preamble | Added paragraph that clarifies inclusion of shared tanks in a process unit subject to this subpart. |
| 60.482–2(a)(1) | 71 FR 65307, column 1, and section IV.B.1 of this preamble. | Added clarification for pumps that begin operation in light liquid service after the initial startup date for the process unit. |
| 60.482–2(a)(2) | | Added reference to 40 CFR 60.482–1(f) as an exception to the requirement for weekly visual inspections of pumps in light liquid service. |
| 60.482–2(b)(2) | 71 FR 65304, column 2, 71 FR 65306, column 1, and section 5.2.2 of RTC. | Added monitoring and repair requirements if weekly visual inspection of pumps in light liquid service indicates liquids dripping from pump seal. |
| 60.482–2(c)(2) | 71 FR 65307, column 1 | Added examples of first attempt at repair practices for pumps in light liquid service. |
| 60.482–2(d) | | Editorial correction and clarification to address renumbering of paragraphs (d)(1) through (6). |
| 60.482–2(d)(1)(ii) | | Replaced first word "Equipment" with "Equipped." |
| 60.482–2(d)(4)(i) | | Renumbered paragraph (d)(4) as (d)(4)(i). |
| 60.482–2(d)(4)(ii) | 71 FR 65304, column 2, 71 FR 65306, column 1, and section 5.2.2 of RTC. | Added monitoring and repair requirements if weekly visual inspection of a pump equipped with dual mechanical seals indicates liquids dripping from pump seal. |
| 60.482–2(d)(5)(i) | | Removed "and" from end of sentence. |

TABLE 1.—SUMMARY OF FINAL AMENDMENTS TO 40 CFR PART 60, SUBPART VV AND RATIONALE FOR CLARIFICATIONS, ADDITIONAL COMPLIANCE OPTIONS, AND TECHNICAL CORRECTIONS—Continued

| Citation | Explanation or location of explanation[1] | Amendment |
|---|---|---|
| 60.482–2(d)(5)(iii) | | Added paragraph to specify how a leak is detected. |
| 60.482–2(d)(6) | 71 FR 65304, column 2 and 71 FR 65306, column 1. | Revised to clarify procedure and time allowed for repair of leaks. |
| 60.482–2(e) | | Revised to add "s" to the end of "no detectable emission." |
| 60.482–3(a) | Section 5.3.5 of RTC | Added reference to exemption in 40 CFR 60.482–3(j). |
| 60.482–3(j) | 71 FR 65308, column 3 | Editorial clarification of section and paragraph references. |
| 60.482–5(a) and (b) | 71 FR 65307, column 2 and section 5.3.5 of RTC. | Rearranged paragraphs within these two paragraphs and made editorial corrections to provide clarity. |
| 60.482–5(b)(2) | 71 FR 65307, column 2, and section 5.4.3 of RTC. | Added provision that containers part of a closed-purge system must be covered or closed when not being filled or emptied. |
| 60.482–5(b)(3) | Section 5.4.1 of RTC | Added provision that gases remaining in the tubing or other apparatus once the closed-purge system valve(s) and sample container valve(s) are closed are not required to be collected or captured. |
| 60.482–5(b)(4)–(b)(4)(iv)(A)–(C) | Rearranged paragraph numbering and made a few editorial clarifications. | Same as current paragraph (b)(4) except for editorial clarifications. |
| 60.482–5(b)(4)(iv)(D) | Section 5.4.2 of RTC | Added provision for use of a waste management unit meeting the requirements of 40 CFR 61.348(a). |
| 60.482–5(b)(4)(iv)(E) | Section 5.4.2 of RTC | Added provision for use of a device used to burn off-specification used fuel oil in accordance with 40 CFR part 279, subpart G. |
| 60.482–6(a)(1) | Section 5.3.5 of RTC | Added reference to exemptions in 40 CFR 60.482–6(d) and (e). |
| 60.482–7(a)(1) | Corrected section designations | Clarified current paragraph (a) to specify that valves must be monitored monthly except as provided in 40 CFR 60.482–7(f), (g), and (h); 40 CFR 60.482–1(c) and (e); and 40 CFR 60.483–1 and 2. |
| 60.482–7(a)(2)(i) and (ii) | 71 FR 65307, column 1, and section IV.B.1 of this preamble. | Added clarification for valves that begin operation in light liquid service after the initial startup date for the process unit. |
| 60.482–7(c)(1)(i) | | Paragraph (c)(1) redesignated as paragraph (c)(1)(i). |
| 60.482–7(c)(1)(ii) | 71 FR 65307, column 3 through 71 FR 65308, column 1, and section 5.1.2 of RTC. | Added paragraph to allow an owner or operator to subdivide valves in a process unit. |
| 60.482–8(a)(2) | Section 5.7 of RTC | Added clarification that audio visual olfactory indications of potential leaks should be eliminated within 5 calendar days of detection. |
| 60.482–8(d) | 71 FR 65307, column 1 | Revised to require that first attempt at repair of pumps and valves in heavy liquid service, pressure relief devices in light liquid or heavy liquid service, and connectors must include best practices under 40 CFR 60.482–2(c)(2) and 40 CFR 60.482–7(e). |
| 60.482–9(a) | Section 5.9.3 of RTC | Clarified that for repair that occurs during a process unit shutdown, monitoring to verify that repair must occur within 15 days after startup of the process unit. |
| 60.482–9(f) | Section 5.9.3 of RTC | Added new paragraph for a leaking pump or valve for which a delay in repair is allowed. |
| 60.483–1(d) and 60.483–2(b)(5) | | Added reference to new 40 CFR 60.485(h) that provides more detailed explanation for calculating the percent of valves leaking. |
| 60.483–2(a)(7) | 71 FR 65307, column 1, and section IV.B.1 of this preamble. | Added clarification for valves that begin operation in light liquid service after the initial startup date for the process unit. |
| 60.483–2(b)(7) | | Added paragraph to specify that a new valve must be monitored according to 40 CFR 60.482–7(a)(2)(i) or (ii) before the provisions of 40 CFR 60.483–2 can be applied to the valve. |
| 60.484(a) | 71 FR 65308, column 3 | Editorial correction. |
| 60.484(b)(2) | | Editorial clarification. |
| 60.485(b) | | Revised reference to nonexistent 40 CFR 60.482 to refer to 40 CFR 60.482–1 through 40 CFR 60.482–10. |
| 60.485(e) | 71 FR 65308 | Clarified that the requirements apply to a piece of equipment. |
| 60.485(e)(1) and (2) | Section 6.3 of RTC | Clarified to specify that light liquids are organic compounds. |
| 60.485(g)(4) | Corrected exponents in equation | Corrected equation for the net heating value of the gas being combusted in a flare. |
| 60.485(g)(5) | | Added ASTM D6420–99 as an alternative to EPA Method 18. |
| 60.485(h) | Section 5.1.4 of RTC | Added equation and clarifications for calculating percent of valves leaking. |
| 60.486(e)(2)(ii) | Section 7.4 of RTC | Revised to allow an alternative to requiring a signature for the list of equipment with no detectable emissions. |
| 60.486(e)(6) | Section 3.3 of RTC | Added recordkeeping requirements for equipment in VOC service less than 300 hours per year. |
| 60.487(c)(2)(i), 60.487(c)(2)(iii), 60.487(c)(2)(iv). | These changes are related to rearranging of paragraphs in 60.482–2. | Corrected references to specific sections and other editorial corrections. |

[1] RTC refers to *Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry and Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries. Background Information for Final Standards. Summary of Public Comments and Responses.* See Docket ID No. EPA–HQ–OAR–2006–0699.

## IV. Summary of Comments and Responses

We proposed amendments to 40 CFR part 60, subpart VV and 40 CFR part 60, subpart GGG on November 7, 2006 (71 FR 65302). We published a NODA regarding OEL on July 9, 2007 (72 FR 37157). A total of 28 comment letters were received during the comment periods for the two notices. In response to these public comments, several changes were made in developing these final amendments and new standards. The major comments and our responses are summarized in the following sections. A summary of the remainder of the comments received during the comment period and responses thereto can be found in the docket for the final amendments and new standards (EPA–OAR–HQ–2006–0699).

### *A. Applicability*

1. Affected Sources Under the Current NSPS

*Comment:* Numerous commenters objected to the proposed application of substantive new requirements to affected sources that became subject to 40 CFR part 60, subpart VV (or any of the subparts that reference subpart VV) on or before November 7, 2006 (hereafter referred to as "subpart VV sources"). Proposed provisions that these commenters considered to be substantive are: (1) Changes to the definition of process unit; (2) annual EPA Method 21 monitoring of OEL; (3) bypass monitoring requirements for closed vent systems to control devices; (4) calibration drift assessments; (5) initial monitoring requirements for pumps and valves; and (6) maintaining records of all monitoring results. The commenters argued that applying the new provisions to subpart VV sources is unlawful.

To address the issue of compliance dates, several commenters recommended that EPA amend 40 CFR part 60, subpart VV so that it applies only to existing sources and develop a new 40 CFR part 60, subpart VVa that applies to affected sources that commence construction, reconstruction, or modification after November 7, 2006.

In contrast, two commenters urged EPA to apply the proposed requirements to all existing SOCMI and refinery process units, and a third commenter recommended applying the proposed leak definitions for pumps and valves to all SOCMI and refinery affected sources. All of these commenters noted that existing facilities are more likely than new sources to have problems with leaks and, thus, should receive extra scrutiny.

*Response:* In this action, EPA has decided to include any new requirements in a new 40 CFR part 60, subpart VVa, consistent with the commenter's suggestions. The new standards in subpart VVa include lower leak definitions for pumps (2,000 ppm) and valves (500 ppm), monitoring of connectors, a calibration drift assessment, and expanded recordkeeping requirements. The proposed requirement to monitor bypass lines has not been included in the new standards because few facilities capture and vent equipment leak emissions to a control device. Additionally, most control devices would be subject to other standards. The proposed requirement to monitor OEL has not been included in the new standards because this requirement has been determined to not be cost-effective. The cost-effectiveness for SOCMI was found to be $3,800/ton for 25 tons/yr of VOC emission reductions. For petroleum refineries, the cost-effectiveness was found to be $14,700/ton for 2.4 tons/yr of VOC emission reductions. Taking the low emission reductions into consideration, the Agency has determined that monitoring OEL is not BDT. As discussed in sections IV.B.1 and IV.A.2 of this preamble, the initial monitoring requirements for new pumps and valves and the changes to the definition of "process unit" are not new standards, and these changes are retained in the final amendments to 40 CFR part 60, subpart VV as well as being included in the new subpart VVa.

Instead of referencing 40 CFR part 60, subpart VVa from 40 CFR part 60, subpart GGG, we decided to create a new 40 CFR part 60, subpart GGGa that applies to new petroleum refining affected sources. This new subpart GGGa references all of the new standards in subpart VVa except for the monitoring requirements for connectors. Reasons for the differences in standards between subparts VVa and GGGa are described elsewhere in this preamble.

Sources subject to 40 CFR part 60, subpart DDD and 40 CFR part 60, subpart KKK, and sources subject to the Refinery NESHAP (40 CFR part 63, subpart CC), but not subject to 40 CFR part 60, subparts VV or GGG, are not required to comply with 40 CFR part 60, subpart VVa at this time.

While we understand there is a concern that existing sources are more likely to leak, there is no provision in section 111 of the CAA that allows us to retroactively apply new standards to sources already subject to the NSPS. EPA agrees with the statements made by the commenters that relate to the application of new requirements under NSPS to existing sources. Section 111 of the CAA does state that NSPS will apply only to new, reconstructed, or modified sources after the date of proposal. The authority to regulate existing sources under section 111(d) of the CAA does not authorize EPA to regulate criteria pollutants or precursors to such pollutants. Therefore, we have not included any new requirements for existing sources in the final amendments to 40 CFR part 60, subpart VV and subpart GGG. These requirements will apply only to sources that commence construction, reconstruction, or modification after the November 7, 2006 proposal date.

2. Definition of Process Unit

*Comment:* Numerous commenters expressed concern that the revised definition of process unit is inconsistent with EPA's original intent when 40 CFR part 60, subpart VV was proposed (i.e., it expands the scope), that it complicates compliance, or that it creates additional confusion. One commenter stated that under the existing definition, a component is part of a process unit based on its function, not whether it is classified as a specific type of equipment. The commenter indicated that since 1981, sources and their regulators have decided what constitutes a process unit based on what equipment serves the functions described in the definition, and this process unit may be different from process units under other rules.

After reading the preamble discussion of the proposed change, one commenter expressed concern that the proposed definition inadvertently includes valves and other equipment on storage tanks. Other commenters objected to the inclusion of all feed, intermediate, and product storage vessels and transfer operations in the definition because the following discussion from the original rulemaking notice for 40 CFR part 60, subpart VV (46 FR 1139, January 5, 1981) makes it clear that EPA's original intent was to include storage in the process unit only if it is within the battery limits of the process:

"A process unit is specifically defined as equipment assembled to produce one or more of the chemicals listed in proposed appendix E which can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the final product. A process unit includes intermediate storage or surge tanks and all fluid transport equipment connecting reaction, separation, and purification devices. All equipment within the battery limits is included. However,

offsite fluid transport and storage facilities are excluded."

Several commenters described ways the proposed change could complicate compliance. For example, two commenters indicated that it would increase the difficulty of tracking equipment, process units, and applicable requirements at refineries where the storage and transfer areas are consolidated into "logistical process units" that support numerous process units, particularly when storage tanks are shared by multiple process units. One commenter added that it may also either restrict the ability of a facility to use its tanks as needed, because they will have been forced into an arbitrary association with a given unit, or create a useless recordkeeping exercise each time a tank switches contents or services a different process. To avoid immediate compliance problems for affected sources that are currently subject to 40 CFR part 60, subpart VV, a commenter requested that existing facilities be allowed 180 days after promulgation of the amendments so that they will have time to include the additional equipment in the applicable LDAR programs. Commenters also noted that the rule should clarify how to assign storage vessels and transfer racks that are shared by multiple processes; they suggested using language in the HON and the Refinery NESHAP as a guide. One commenter stated that EPA should clarify that a compressor is still a separate affected facility from the group of equipment in a refinery process unit under 40 CFR part 60, subpart GGG.

*Response:* The first sentence in the definition of "process unit" in the final amendments and new standards includes the term "components" as in the existing definition rather than "equipment" as in the proposed amendments. This correction distinguishes major process vessels such as reactors and distillation units (i.e., "components") from pieces of equipment, as defined in the rule, that are subject to the LDAR standards. In addition, the last sentence of the proposed definition has been replaced to reference "equipment" as it is defined in the applicable subpart. This change should address concerns that compressors at petroleum refineries are separate affected sources. Otherwise, there are no differences between the proposed and final definitions.

The amended definition of process unit clarifies EPA's original intent and is consistent with the language provided by the commenters from the January 1981 rulemaking. It is clear from the 1981 rulemaking that all equipment that is located within the battery limits is included as part of the process unit. Likewise, there is no question that any fluid transport and storage facilities located outside of the facility property are not included. However, the 1981 language also states that a process unit includes storage tanks and all fluid transport equipment. There is no specification that these components are only included if within the battery limits. There has been confusion in the past regarding the inclusion of components outside of the battery limits but within the property of the facility. To clarify this issue, EPA previously issued formal guidance (see April 6, 1994 letter from John Rasnic to Raymond Hiley in Docket ID No. EPA-HQ—OAR–2006–0699).

We agree that the determination of whether a particular tank is a storage tank, feed tank, or intermediate tank and part of a process unit must be done on a site-specific basis, dependent on how the tank functions within a particular plant site. The physical proximity of the storage tank to the other processing equipment within a process unit is not a sole determinate in establishing whether a storage tank is part of the process or not.

The final amendments and new standards include provisions for assigning a shared storage tank to a specific process unit for the purposes of an LDAR program. The owner or operator will need to determine what process units the storage tank is associated with. They will then determine which process unit, or combination of units subject to the same subpart, has the greatest annual quantity of stored materials in that tank. The subpart that the process unit (or combination of units subject to the same subpart) associated with the greatest use of that tank is subject to will be the applicable subpart for the tank. The process unit, which is subject to the same subpart as the tank, with the greatest annual quantity of stored materials in that tank will be the process unit the tank is assigned to. If a tank is shared equally between two process units that are subject to 40 CFR part 60 standards, the process unit with the most stringent requirements will be the unit the tank is assigned to. For example, if the predominant use of a storage tank is to service a process unit subject to 40 CFR part 60, subpart VV, that storage tank is a part of that process unit and subject to subpart VV and the equipment must be monitored at a leak definition of 10,000 ppm.

*Comment:* Two commenters wondered how the change in the definition of "process unit" would affect modification and reconstruction determinations. One commenter expressed concern that it will make it easier for an owner or operator to add new equipment to an existing process unit without triggering the threshold that would make the process unit a new affected source. The second commenter noted that including feed tanks in the definition changes the basis for the modification and reconstruction cost test and asked how changes that have already occurred should be handled in this determination.

*Response:* Since the amended definition is a clarification of our original intent with respect to applicability of 40 CFR part 60, subpart VV to equipment on storage tanks and lines between storage tanks and processing equipment, there will be no impact on modification or reconstruction determinations. If a facility believes that they have performed a previous modification or reconstruction determination in error, they should contact their delegated authority.

*B. Standards*

1. Initial Monitoring of Pumps and Valves

*Comment:* Numerous commenters objected to the proposed clarifications for the initial monitoring of pumps and valves that are installed after the startup of the process unit. Several commenters stated that the proposed provisions are significant new requirements and cannot be finalized without demonstrating that they represent BDT and giving the public a chance to comment on the supporting analyses. Two commenters indicated that they are unaware of any SOCMI facilities that routinely monitor new pumps and valves within 1 month of startup, and the supporting documentation for the proposal contains no data from SOCMI sources. Several commenters requested that EPA allow at least 90 or 180 days because complying within 1 month would be burdensome, particularly for facilities that use third party contracting for monitoring; 1 month is not enough time to integrate new equipment into the monitoring program; 40 CFR 60.8 of the General Provisions provides 180 days for performance tests; and EPA has not explicitly stated how monitoring within 1 month will reduce emissions. Two commenters noted that EPA's justification of the requirement for valves is that it is needed to ensure that the valve does not leak until its first quarterly or annual monitoring, but no data were presented to show such leakage occurs or is a problem. The

commenters also requested that when establishing the final requirement for initial monitoring of pumps and valves, the timeframe be given in days, not months.

In contrast with the above comments, three commenters supported the proposed language or more stringent requirements. One of these commenters recommended monitoring new pumps within 1 month after installation to minimize the time period for potential leaks. A second commenter recommended that monitoring be required even sooner after installation. This commenter also questioned why a clarification of the requirements for pumps was needed because the preamble to the proposed amendments did not explain how industry currently handles new pumps and why that practice is a problem. This commenter also objected to the second sentence in 40 CFR 60.482–7(a)(2) because it means valves added to a process would not have to be monitored for 2 consecutive months before implementing skip monitoring, which is less stringent than the requirements for valves in an entirely new process.

*Response:* The language pertaining to the initial monitoring of new pumps and valves was added to the final amendments and new standards to clarify how new equipment should be handled in the existing monitoring schedule, but these are not new requirements. Under the current rule, pumps are to be monitored monthly whether they are newly installed or installed prior to the process unit becoming an affected source (40 CFR 60.482–2(a)(1)). It is unclear to us how a facility is complying with the requirements for pumps if they are not being monitored monthly. Also under the current rule, all new valves are to be monitored monthly (i.e., base period) until two consecutive monthly readings are found below the applicable leak definition, at which point the valve may be monitored quarterly until a subsequent leak is found (40 CFR 60.482–7(a)). Finding of a subsequent leak reverts the monitoring back to monthly until two consecutive monthly readings below the applicable leak definition is reestablished. The current rule also has an alternative standard for valves at 40 CFR 60.483–2 which allows for longer "skip" periods based on continued performance. Again, we are uncertain that a facility is complying with the requirements for these valves if they are not monitoring new valves within the first month of operation.

However, to provide operational flexibility, we have decided to add an option for newly installed valves in the final amendments and new standards. If a new valve is placed into service during a skip period, the source has the option to either monitor the valve on the monthly schedule and establish the skip period for that valve, or count the valve as a leaker in the percent leaking calculation. If the result of the percent leaking calculation remains below 2.0 percent with the new valve counted as a leaker, the owner or operator must monitor the new valve by the next scheduled skip period or within 90 days, whichever comes first. We have stated the timeframe for these requirements in days instead of months in the final amendments and new standards (30 days for pumps and either 30 or 90 days for valves, depending on whether the owner or operator is complying with the skip monitoring option).

*Comment:* Three commenters requested clarification of the applicability of the proposed initial monitoring provision. Two commenters stated that the term "placed in service" clearly implies that pumps and valves should follow the initial monitoring schedule after they are initially installed. However, the term "placed in service" also implies that previously installed pumps and valves should be monitored after they have been placed back into service after maintenance, turnarounds, and repairs. Both commenters recommended changes to clarify that only newly installed or rebuilt pumps and valves should be monitored following the schedule for initial monitoring.

*Response:* The initial monitoring requirement is for pumps and valves that come into VOC service through a process expansion or replacement not associated with a repair (e.g., preventative maintenance). These pumps and valves may be newly purchased or they may be equipment that was previously in service elsewhere in the process unit or facility. A newly purchased, rebuilt, repaired, or remanufactured pump or valve installed to repair a leaking pump or valve is not subject to the initial monitoring requirements. Instead, the pump or valve should be monitored to verify that there is no longer a leak (as required in the definition of "repaired") and may be subsequently monitored according to the schedule that applied to the previously leaking pump or valve.

To further clarify this issue, we have revised 40 CFR 60.482–2(a)(1), 40 CFR 60.482–7(a)(2), 40 CFR 60.483–2(b)(7), 40 CFR 60.482–2a(a)(1), 40 CFR 60.482–7a(a)(2), and 40 CFR 60.483–2a(b)(7).

2. Weekly Pump Inspections

*Comment:* Numerous commenters addressed the proposed changes to the requirements for weekly inspections of pumps. One commenter supported the proposed changes, including the changes to 40 CFR 60.482–2(b)(2)(ii), which states that if a visible liquid leak is found, it may be repaired by removing the visible indication of the leak. Based on the commenter's experience, a visible leak does not always indicate a regulatory leak. Another commenter agreed with the clarification allowing facilities to determine if a leak is emitting VOC using EPA Method 21 because it will help to focus repairs on pumps leaking hydrocarbons.

Three commenters did not support the proposed changes to the weekly inspection requirements. Two of these commenters disagreed with EPA's conclusion that the existing requirements are overly burdensome. According to one commenter, an operator should be required to make a showing of an undue burden; simply stating that an operator may have to conduct more inspections and repair more leaks than absolutely necessary does not demonstrate an undue burden. Two commenters noted that eliminating evidence of liquids dripping does not guarantee that the pump is no longer leaking VOC. As a result, these two commenters stated that monitoring should be required after eliminating evidence of liquids dripping to verify that repair was successful. Even if liquids dripping are not process fluid, one commenter noted that the liquid is probably either seal barrier fluids or condensate from a pump jacket used for temperature control. Regardless of the cause or fluid, one commenter noted that any liquid dripping may be a first sign of a potential maintenance problem that is best addressed as soon as possible as a matter of good operational practice as well as good environmental practice.

*Response:* The aim of the LDAR program is to find and repair leaks of VOC. In some instances, the liquids found dripping from pumps are not VOC-containing liquids or otherwise would not meet the leak definition. In these cases, the pump would not be required to be repaired under the LDAR program. Adding the option to monitor allows the owner or operator to determine if the liquids dripping constitute a VOC leak, thus focusing their efforts on reducing VOC emissions. If the owner or operator chooses not to monitor the pump to determine if the liquids dripping are a VOC leak, the liquids dripping from the pump are

classified as a VOC leak. The leak must be repaired by eliminating indications of liquids dripping, and the appropriate recordkeeping and reporting requirements for leaks apply to that pump. We agree with the commenter that persistent liquids dripping may indicate an operation problem that should be addressed by maintenance. If indications of liquids dripping are noted for one pump during multiple weekly inspections, we encourage facilities to ensure that the pump is operating properly. We do not agree that more frequent EPA Method 21 monitoring is necessary because pumps are currently monitored on a monthly basis and the additional monitoring would not result in substantial emission reductions.

3. Connectors

*Comment:* In response to our request for comments regarding whether connector monitoring should be required, three commenters expressed support for it, and nine commenters opposed it. Supporters argued that significant reductions could be achieved at a reasonable cost. Opponents argued that the impacts analysis overstated the emission reductions and underestimated the costs. According to two of the opponents, EPA did not require connector monitoring in the MON (40 CFR part 63, subpart FFFF) because the cost was determined to be unreasonable. One commenter indicated that monitoring as proposed is not worth the effort because most connectors are adjacent to valves, and these connectors are investigated and monitored when valve monitoring results in abnormal readings.

Six commenters objected to some of the assumptions we used to estimate equipment leak emissions. Some of these commenters stated that our emission reduction estimates were high because we used assumed leak frequencies and leak rates from *Protocol for Equipment Leak Emission Estimates* (EPA–453/R–95–017, November 1995) (the Protocol document) rather than actual field data. One commenter added that these data often predict emissions an order of magnitude higher than the actual emissions. Another commenter submitted a report that concluded there is no statistical difference in average leak rates between initial and subsequent monitoring at HON and MON units. This commenter also questioned the assumption that all leaking connectors would be successfully repaired after each monitoring cycle. Several commenters objected to estimating emissions based on leak rates equal to 170 percent of actual observed leak rates. One commenter noted that one refinery monitored more than 22,000 connectors and found only four leaking at greater than 1,000 ppm. Less than 0.5 percent of the connectors in process units subject to the HON at another refinery were leaking at greater than 500 ppm.

Four commenters objected to various elements in the cost estimates. These commenters noted that more connectors than valves are difficult to monitor, and the cost analysis did not include the cost for the additional labor and equipment needed to monitor these connectors. One commenter stated that the unit cost for monitoring connectors should be more than $1.50 per connector because the time required to monitor a connector is longer than for other types of equipment. The increased monitoring time is the result of several factors: (1) The distance that must be traversed per component is greater; (2) connectors often are in hard-to-reach locations, requiring the operator to squeeze through small spaces, often having to remove the monitor backpack; and (3) connectors tend to be spread out and are hard to find. In addition, this commenter noted that recordkeeping for connectors is more burdensome and complicated than for valves. Connectors are not typically shown on process and instrumentation drawings, making them difficult to find. The commenter stated that our estimate of 10 hours per year to complete administrative tasks and reports associated just with monitoring connectors is inadequate. Finally, the commenter noted that our cost estimates omit the cost of a data collection system or monitoring device rental; the commenter estimated these costs to be $14,500 for data collection systems and $135 per day for monitor rental. The commenter stated that even if a facility has a data collection system, additional licenses are needed to add connectors. Another commenter stated that rationale for requiring monitoring at SOCMI facilities does not apply to natural gas processing plants; thus, this commenter requested that an impact analysis be performed to address natural gas processing plants before making that industry subject to connector monitoring.

In contrast with the above comments, three commenters were in favor of adding connector monitoring to the rule. One commenter suggested that connectors be monitored annually or biennially because they have significant leak potential that would go undetected without monitoring. Regardless of the uncertainties in the leak rates and emissions factors, another commenter stated that connector monitoring should be required because emissions reductions can be achieved at a relatively low cost. The third commenter supported a requirement to monitor connectors at SOCMI sources because it is technically feasible, our impacts analysis shows it is economically feasible, and it would achieve greater reductions than the proposed amendments for pumps and valves. According to this commenter, more accurate emissions data in the impacts analysis is unnecessary because emissions inventories based on monitoring data typically show emissions that are higher than the emissions estimated using engineering calculations and emission factors, which would only strengthen the argument for monitoring. This commenter also argued that refineries should be required to monitor connectors because such monitoring is technically feasible, it is already required for some refineries in Texas and California, and our impacts analysis showed connectors at refineries were more likely to leak than connectors at SOCMI sources.

*Response:* Both the HON and MON regulations are based on emissions of hazardous air pollutants (HAP). NSPS are based on VOC emissions (both HAP and non-HAP). When calculating the cost-effectiveness for NSPS, there are more possible emission points and a higher percentage of regulated pollutants in the emissions because the analysis is not based only on HAP emissions. This results in a different conclusion for cost-effectiveness than in the HON or MON.

The commenter's claim that we used the leak frequencies and leak rates in the Protocol document for the SOCMI analysis is incorrect. We used the same initial leak frequency (0.36 percent) as in the MON analysis. We also started with the same initial leak rate (0.000186 kilogram (kg)/hour (hr)/connector), but we then escalated it in the same manner that leak rates for pumps and valves were escalated. The leak frequencies and leak rates in the MON analysis were based on industry-supplied data for almost 165,000 connectors. We decided not to use the leak rate data in the report supplied by one of the commenters because it contains a smaller data set (29,000 connectors), and it is possible that these data are also included in the larger data set. However, our assumption that the subsequent leak frequency is the same as the initial leak frequency is consistent with the conclusion in the report cited by the commenter.

The new standards in 40 CFR part 60, subpart VVa include connector monitoring because we have determined

that it is cost-effective at SOCMI sources. The specific monitoring provisions are the same as in the Generic MACT. However, we have determined that connector monitoring is not cost-effective for petroleum refineries. Therefore, an exemption from the provisions for connector monitoring has been included in 40 CFR part 60, subpart GGGa. At this time, we are not reviewing 40 CFR part 60, subpart KKK; therefore, no cost analysis has been performed on connector monitoring for these sources, and natural gas processing plants subject to 40 CFR part 60, subpart KKK are not subject to the connector monitoring requirements in subpart VVa.

After reviewing the comments, we revised the impacts analyses to include two of the suggested changes to the cost estimates. First, we corrected an error, which increased the estimated time for reporting and administrative activities related to connectors from 10 hr/year (yr) to 50 hr/yr. Second, although we are not aware that monitoring contractors charge a higher fee for connectors than for other equipment, we accept the commenter's suggested fee of $2.50/connector because the $1.50/connector that we used in the original analysis may be closer to the low end of the range than the average. We disagree with the other changes suggested by the commenters. Details of the revised impacts analysis, including rationale for not making the suggested changes, are provided in the docket (Docket ID No. EPA–HQ–OAR–2006–0699).

*C. Test Methods and Procedures*

*Comment:* Two commenters supported the requirement to conduct calibration drift assessments and remonitor when the assessment shows a negative drift of more than 10 percent. Other commenters acknowledged that a drift check is a good practice or a useful quality assurance/quality control (QA/QC) tool, and one commenter agreed with EPA's rationale for requiring drift checks.

On the other hand, four commenters opposed the drift check requirement, saying it is unnecessary and provides no environmental benefit. One of these commenters added that monitoring instruments such as the Foxboro TVA 1000 FID/PID or Foxboro TVA 1000B are quite stable over a 24-hour period, and EPA has not presented data or an analysis showing the need for calibration assessments. A second commenter noted that instruments typically drift in a positive direction. A third commenter argued that a drift check and re-monitoring is a futile effort to make the equipment leak monitoring method more accurate than was originally intended and than the instruments can achieve because of the following: (1) The Foxboro TVA 1000B instrument accuracy is only ±25 percent for readings between 1 and 10,000 parts per million by volume (ppmv); (2) a response factor as high as 10 is allowed for compounds of interest; (3) the 10 percent drift limit is inconsistent with the level of the instrument's accuracy allowed by EPA Method 21; and (4) leaking equipment does not emit a constant concentration. In addition, this commenter noted that drift checks conducted to satisfy consent decrees have shown only about 10 percent of instruments drift more than 10 percent every 2 to 3 weeks, and the release of calibration gases would be considered a negative environmental impact.

*Response:* We are removing the requirement for a post-test calibration drift assessment from the final amendments but retaining the requirement for the new subparts. Post-test calibration drift assessments constitute good practice and are a useful QA/QC tool to validate the proper operation of the monitor during the monitoring period and, hence, the measurement data. The requirement for a calibration drift assessment is not an effort to make the method more accurate than was originally intended, but is intended as an additional quality assurance check.

*Comment:* Numerous commenters considered the proposed re-monitoring requirement to be excessive. Instead of re-monitoring when instrument readings are greater than 20 percent of the applicable leak definition, two commenters suggested changing the threshold to 75 or 80 percent. Another commenter suggested using a percentage equal to 100 minus the percent of negative drift. If re-monitoring is required when negative drift occurs, two commenters stated that an owner or operator should also have the option of re-monitoring when positive drift occurs and reclassifying leakers as nonleakers. One of these commenters also suggested four additional changes: (1) Because monitoring shifts may vary, require the assessment at the end of each day rather than the end of each monitoring shift; (2) allow an unlimited number of calibration drift assessments per day; (3) determine drift relative to the most recent calibration value rather than the initial value for the day; and (4) specify that a drift assessment is not required after re-monitoring.

*Response:* We agree with the suggestion to establish the retest criterion at the percentage equal to 100 minus the percent of negative drift and are modifying the requirement accordingly. We also agree with the commenter's suggestion that an owner or operator should have the option of re-monitoring when positive drift occurs and reclassifying leakers as non-leakers when the re-monitoring after recalibration due to positive drift indicates the previously identified leak is below the leak definition concentration. We agree that monitoring shifts may vary, and the new standards require the assessment at the end of each day rather than the end of each monitoring shift. The new standards allow an unlimited number of calibration drift assessments per day, and we have clarified that the drift assessment is determined relative to the most recent calibration value rather than the initial value for the day. We do not agree that a drift assessment is not required after remonitoring and have not made this change to the new standards.

*D. Recordkeeping and Reporting*

*Comment:* One commenter supported the proposed requirement to keep records of all monitoring results because more and better data can only help facility owners and operators efficiently and effectively address the problem of fugitive emissions. Another commenter stated that records of weekly pump inspections are needed to make the inspection requirement enforceable. On the other hand, many commenters either opposed or urged us to reconsider the need for one or more of the following proposed recordkeeping requirements: (1) Results of all monitoring events; (2) time of each monitoring event; (3) information related to the proposed initial monitoring requirement for pumps and valves added to a process unit; (4) results of the proposed monitoring of OEL; (5) information related to the proposed requirement to monitor bypass lines; (6) results of calibration drift checks; and (7) results of weekly pump inspections.

Several commenters stated that the additional recordkeeping would be burdensome and either would not improve the rule's effectiveness or is excessive relative to any minimal improvement in performance. In addition, one commenter stated that the proposal preamble did not adequately explain how we estimated the cost of the additional recordkeeping and reporting for SOCMI sources to be $369,000/yr, and another stated that the proposal preamble did not explain why the current monitoring requirements are not sufficient to verify that monitoring was performed. According to one commenter, recording the time of

monitoring has hindered many programs and reduced productivity, and the additional records will generate an administrative backlog of data and create issues with storage and accessibility. Although this commenter agreed that the proposed records can be useful in verifying quality control of the LDAR program, the commenter asserted that a more cost-effective way to achieve quality control is to physically monitor the program. Furthermore, this commenter stated that by requiring the records, we are specifying the means by which a facility must implement the LDAR program rather than outlining the performance standard. Another commenter expressed concern that the additional recordkeeping exposes facilities to the potential of incurring deviations for records that serve no purpose.

*Response:* As stated in section III.B of this preamble, the recordkeeping requirements in the final amendments and new standards are authorized by section 114 of the CAA. We have made significant changes to the proposed recordkeeping requirements as a result of the changes made to the scope and applicability of the standards. Because the final amendments to 40 CFR part 60, subparts VV and GGG include only clarifications to existing requirements, burden reducing provisions, and new compliance options, no changes or additions to the recordkeeping requirements in subpart VV or GGG are needed to document and/or enforce these amendments. The recordkeeping requirements apply to the new standards (40 CFR part 60, subparts VVa and GGGa), as proposed, with a few exceptions. First, we removed the requirement to record the time of each monitoring event because the total number of pieces of equipment that are monitored each day should be sufficient for evaluating the ability of an operator to properly perform EPA Method 21. Second, records of information on bypass lines are not required because the new subpart does not include the requirement to monitor bypass lines. Third, because sources subject to subpart GGGa are not required to comply with the monitoring requirements applicable to connectors, the associated recordkeeping requirements do not apply to those sources. CAA section 114 specifically provides that we may have access to and copy any records and inspect any monitoring equipment and compliance method.

*E. Burden Estimates*

*Comment:* According to one commenter, the burden impact analyses of the proposed new recordkeeping and reporting requirements as presented in the preamble and docket do not comply with the ICR requirements of the Paperwork Reduction Act (PRA). The proposed new requirements of concern to the commenter are the requirements to keep records of information for all monitoring events, the time of each monitoring event, the time a new pump or valve is placed in service and results of new monitoring requirements for such pumps and valves, results from the new monitoring requirement for OEL, results of the new calibration drift checks, and results of weekly pump inspections. Another commenter also stated that the ICR requirements in the PRA were not met for recordkeeping and reporting associated with the proposed initial monitoring requirement for valves. A third commenter expressed a general concern that the proposed recordkeeping requirements may not meet the administrative requirements for proposing new NSPS.

One commenter noted several specific deficiencies and concerns with the burden impact analyses. First, it is not clear if all of the proposed new requirements are addressed in the ICR for sources subject to NSPS 40 CFR part 60, subpart GGG because the ICR does not discuss the incremental effects of the new requirements. Second, the ICR for SOCMI sources appears to address impacts only for those sources that elect to comply with the CAR option, not those that would comply directly with 40 CFR part 60, subpart VV. Third, no ICR analyses were provided for sources that are subject to other rules that reference subpart VV (i.e., NSPS subparts DDD and KKK of 40 CFR part 60, and the Refinery NESHAP). Fourth, the available analyses appear to address burden impacts only for sources that become subject to subparts VV and GGG in the future, but the proposed new requirements also would apply to sources that are currently subject to subpart VV or any of the rules that reference it. Fifth, even if some facilities voluntarily collect some of the records of concern, a requirement making their collection mandatory is still subject to the PRA, Regulatory Flexibility Act, and Executive Order 12866. Sixth, the commenter noted that the claim in the preamble that records of all monitoring events would be "useful" is not a legal basis for imposing the recordkeeping requirement. Seventh, if the total burden for all of the sources exceeds $100 million per year, additional review is triggered under other laws and Executive Order 12866. Based on the lack of analyses, the commenter stated that proposed recordkeeping and reporting requirements cannot be imposed on any sources, except perhaps new sources subject to subpart GGG, without additional proposal notice and opportunity for public comment.

*Response:* We disagree with the conclusions drawn by the commenters regarding the availability of the ICR. Document number EPA–HQ–OAR–2006–0699–0038 is the ICR associated with the CAR and all subparts that reference the CAR. This supporting statement displays the burden for sources that opt to comply with the CAR and for sources that opt to comply with their own referenced subpart, including 40 CFR part 60, subpart VV. For reference, pages 2–3, 6–7, 12–16, 33, 53, 77, and 112 all provide information specific to 40 CFR part 60, subpart VV.

For the final amendments and new standards, we have made adjustments to the supporting statements for all subparts involved. The burden associated with the amended 40 CFR part 60, subpart VV and the new 40 CFR part 60, subpart VVa is included in the supporting statement for the CAR and all other referenced subparts. The burden associated with the amended 40 CFR part 60, subpart GGG and the new 40 CFR part 60, subpart GGGa is included in the supporting statement that originally just supplied information for subpart GGG.

Because this particular rulemaking did not evaluate sources subject to 40 CFR part 60, subparts DDD and KKK or the Refinery NESHAP, we have not included any changes to the associated ICR for these subparts.

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

In setting standards, the CAA requires us to consider alternative emission control approaches, taking into account the estimated costs and benefits, as well as the energy, solid waste, and other effects. We are presenting estimates of the impacts for the 500 ppm leak definition for valves and the 2,000 ppm leak definition for pumps in 40 CFR part 60, subparts VVa and GGGa and connector monitoring in subpart VVa. The final amendments are clarifications to the existing subpart VV and subpart GGG to 40 CFR part 60; they have no associated emission reduction impacts. The cost, environmental, and economic impacts of the new standards are expressed as incremental differences between the impacts of SOCMI and petroleum refining process units complying with the new subparts and the current NSPS requirements (i.e., baseline). The impacts are presented for SOCMI and petroleum refining process

units constructed, reconstructed, or modified over the next 5 years. The analyses and the supporting documentation referenced below can be found in Docket ID No. EPA–HQ–OAR–2006–0699.

EPA estimates that there are no significant energy or secondary environmental impacts as a result of the new standards. The new standards are changes to work practice requirements and do not require changes to equipment or control devices. Therefore, use of fuel or electricity is not expected to increase significantly as a result of the new standards. Likewise, the new standards do not require physical changes that have the potential to increase wastewater or solid waste from SOCMI or petroleum refinery process units.

*A. What are the impacts for SOCMI process units?*

The methodology used to estimate impacts for the lower leak definitions for pumps and valves in the new 40 CFR part 60, subpart VVa is essentially the same as the methodology described in section VI.A of the preamble for the proposed amendments (71 FR 65311, November 7, 2006). There are, however, a few changes in the assumptions. We adjusted the estimates of baseline emissions and monitoring frequencies for new, modified, and reconstructed process units not subject to the HON, the MON, or the Ethylene NESHAP to better reflect baseline conditions.

In addition, we added emission reduction and cost impacts for the monitoring of connectors. The analysis completed for the proposed amendments to 40 CFR part 60, subpart VV was documented in a technical memorandum (EPA–HQ–OAR–2006–0699–0035). Based on the leak frequencies obtained from *Revised MACT Floor, Regulatory Alternatives, and Nationwide Impacts for Equipment Leaks at Chemical Manufacturing Facilities* (EPA–HQ–OAR–2003–0121–0004) at a leak definition of 500 ppm, we estimated that connectors would be monitored once every 4 years. SOCMI process units subject to the HON are already required to monitor connectors, so the baseline impacts for process units subject to these standards were equivalent to the impacts of the new standards. The methodology did not change for the analysis of the impacts for connectors subject to the new subpart VVa of 40 CFR part 60.

Based on the assumptions described above, we estimate that the new standards will reduce emissions of VOC about 325 tons/yr from the baseline. The estimated increase in annual cost, including annualized initial costs, is about $821,000. The cost-effectiveness is about $1,700 per ton of VOC removed. The estimated nationwide 5-year incremental emissions reductions and cost impacts for each of the new standards are summarized in Table 2 of this preamble.

TABLE 2.—NATIONAL EMISSION REDUCTIONS AND COST IMPACTS FOR SOCMI UNITS SUBJECT TO STANDARDS UNDER SUBPART VVA OF 40 CFR PART 60

[5th Year After Proposal]

| Requirement | Annual emission reductions, tons/yr | Total initial cost, $million | Annualized cost, $thousand/yr | Recovery credit,[1] $thousand/yr | Total annual cost, $thousand/yr | Cost-effectiveness, $/ton |
|---|---|---|---|---|---|---|
| Lower leak definition for valves and pumps | 94 | 0.15 | 41 | 77 | −36 | −380 |
| Monitor connectors | 230 | 3.1 | 780 | 190 | 590 | 2,500 |
| Total | 325 | 3.25 | 821 | 270 | 554 | 1,700 |

[1]Value of recovered product is $818/ton.

*B. What are the impacts for petroleum refining process units?*

The methodology used to estimate impacts for the new 40 CFR part 60, subpart GGGa is essentially the same as the methodology described in section VI.B of the preamble for the proposed amendments (71 FR 65311). There are, however, a few changes in the assumptions. For example, we originally assumed that the leak definitions in the Refinery NESHAP for valves and pumps on new sources since July 14, 1994, are equivalent to the leak definitions in 40 CFR part 60, subparts VVa and GGGa. However, the leak definitions in subparts VVa and GGGa are, in fact, more stringent than the Refinery NESHAP (proposed amendments at 72 FR 50716, September 4, 2007, did not include any changes to the equipment leak standards). Therefore, process units subject to both standards will comply with the leak definitions in subpart GGGa, so we revised the analysis of the impacts for the promulgated amendments to include the impacts for sources subject to both the Refinery NESHAP and subpart GGGa. We also adjusted the estimates of baseline emissions and monitoring frequencies for process units not subject to a consent decree. The revised impacts analysis is described in detail in Docket ID No. EPA–HQ–OAR–2006–0699.

We estimate that the new standards will reduce emissions of VOC about 13 tons/yr from the baseline. The estimated increase in annual cost, including annualized initial costs, is about $26,000. The cost-effectiveness is about $1,600 per ton of VOC removed. The estimated nationwide 5-year incremental emissions reductions and cost impacts for the new standards are summarized in Table 3 of this preamble.

TABLE 3.—NATIONAL EMISSION REDUCTIONS AND COST IMPACTS FOR PETROLEUM REFINERY UNITS SUBJECT TO STANDARDS UNDER SUBPART GGGa OF 40 CFR PART 60

[5th Year After Proposal]

| Requirement | Annual emission reductions, tons/yr | Total initial cost, $thousand | Total annual cost, $thousand/yr | Recovery credit,[1] $thousand/yr | Total annual cost, $thousand/yr | Cost-effectiveness, $/ton |
|---|---|---|---|---|---|---|
| Lower leak definition for valves and pumps | 13 | 24 | 26 | 7 | 19 | 1,600 |

[1]Value of recovered product is $545/ton.

*C. What are the economic impacts?*

An economic impact analysis was performed to compare the control costs associated with producing a product at petroleum refineries and various types of SOCMI facilities to the average value of shipments from such facilities. Since we are unable to associate projected control costs with specific facilities, we examined two polar cases for each industry, (1) a worst-case and (2) a best-case scenario. For the SOCMI, the polar cases are: (1) No more than eight complex process units located at a single facility and (2) no more than one process unit per facility. For petroleum refineries, the polar cases are: (1) All of the affected process units associated with one facility in the industry and (2) no more than one affected process unit at any given facility. In all cases, the magnitude of the costs is quite small. The only scenario for which the control costs reach 0.3 percent of the facility value of shipments is if an average ethyl alcohol manufacturing facility (in terms of value of shipments) experienced the worst case scenario of 8 complex processing units requiring control. Therefore, while the distribution of costs to small entities is unknown, no significant impact is expected for facilities of any size. The impact of the regulation on prices and profitability depends on the extent that the costs of control are passed on in the form of higher prices or absorbed by the facility. Because the costs are so small, any price increases or loss of profit would be quite small. No significant impact is expected as a result of the final amendments or the new standards of performance for equipment leaks of VOC for the petroleum refining industry and SOCMI.

## VI. Statutory and Executive Order Reviews

*A. Executive Order 12866: Regulatory Planning and Review*

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

*B. Paperwork Reduction Act*

The final amendments to the standards of performance for SOCMI and petroleum refineries (40 CFR part 60, subparts VV and GGG) do not impose any new information collection burden. The final amendments to these existing rules contain only clarifications, burden reducing provisions, and new compliance options. OMB has previously approved the information collection requirements contained in the existing regulations under the provisions of the Paperwork Reduction Act, 44 U.S.C. 3501, *et seq.*, and has assigned OMB control number 2060–0443, EPA ICR number 1854.04, to the ICR for subpart VV and OMB control number 2060–0067, EPA ICR number 0983.08, to the ICR for subpart GGG. A copy of the OMB-approved ICR may be obtained from Susan Auby, Collection Strategies Division, Environmental Protection Agency (2822T), 1200 Pennsylvania Ave., NW., Washington, DC 20460 or by calling (202) 566–1672.

The information collection requirements in these new final standards (40 CFR part 60, subparts VVa and GGGa) 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.

The information to be collected for the new standards are based on recordkeeping and reporting requirements in the NSPS General Provisions in 40 CFR part 60, subpart A, 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 EPA pursuant to the recordkeeping and reporting requirements for which a claim of confidentiality is made is safeguarded according to EPA policies set forth in 40 CFR part 2, subpart B.

Facilities subject to 40 CFR part 60, subpart VVa are required to comply with the same monitoring, recordkeeping, and reporting requirements for equipment leaks as required by 40 CFR part 60, subpart VV, along with certain additional requirements. The new recordkeeping provisions in subpart VVa require general identifying information for each monitoring activity required by the rule and specific information needed to demonstrate compliance with the new monitoring provisions for connectors and pumps in light liquid service (weekly visual inspections for indications of dripping liquids). Records are also required to demonstrate compliance with the QA/QC requirement for a calibration drift assessment at the end of each day and comparison of the results of the assessment with the most recent calibration value. A new, reconstructed, or modified affected facility subject to 40 CFR part 60, subpart VVa or GGGa must submit a notification of compliance status report and include information about leaking connectors in semi-annual compliance reports. Affected facilities subject to subpart GGGa are required to comply with the monitoring, recordkeeping, and reporting requirements in subpart VVa except for the monitoring requirements applicable to connectors (and the associated recordkeeping/reporting requirements).

The annual average burden for the information collection requirements in 40 CFR part 60, subpart VVa is estimated at 7,194 labor-hours per year, with a total annual cost of $527,104 per year. The hour burden is based on an estimated 29 hours per response on a semi-annual basis by 76 respondents. Total capital/startup costs associated with the monitoring equipment over the 3-year period of the ICR are estimated at $4,200. The operation of the monitors is included in the monitoring costs, and maintenance costs on these units are incidental; therefore, no maintenance or operation costs are incurred.

The annual average burden for the information collection requirements in 40 CFR part 60, subpart GGGa is estimated at 4,216 labor-hours per year, with a total annual cost of $330,353 per year. The hour burden is based on an estimated 70 hours per response on a semi-annual basis by 20 respondents. No capital/startup costs or operation and maintenance costs are associated with the information collection requirements.

Burden means the total time, effort, or financial resources expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal agency. This includes the time needed to review instructions; develop, acquire, install, and utilize technology and systems for the purposes of collecting, validating, and verifying information, processing and maintaining information, and disclosing and providing information; adjust the existing ways to comply with any previously applicable instructions and requirements; train personnel to be able to respond to a collection of information; search data sources; complete and review the collection of information; and transmit or otherwise disclose the information.

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 for the approved information collection requirements contained in the new standards.

*C. Regulatory Flexibility Act*

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 Procedures 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 the final amendments and new standards on small entities, small entity is defined as: (1) A small business according to Small Business Administration size standards by the North American Industry Classification System (NAICS) category of the owning entity; (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 that is independently owned and operated and is not dominant in its field. For the SOCMI, a small business ranges from less than 500 employees to less than 1,000 employees, depending on the NAICS code. For petroleum refiners, a small business has no more than 1,500 employees and a crude oil distillation capacity of no more than 125,000 barrels per calendar day.

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. We have determined that no facilities subject to the final amendments to the standards of performance for the SOCMI (40 CFR part 60, subpart VV) and petroleum refineries (40 CFR part 60, subpart GGG), including small businesses, will incur any adverse impacts because the final amendments do not create any new requirements or burdens. The final amendments include only clarifications, burden-reducing provisions, and new compliance options. We have determined that no facilities, large or small, subject to the new standards of performance for the SOCMI (40 CFR part 60, subpart VVa) or petroleum refineries (40 CFR part 60, subpart GGGa) will incur any economic impact greater than 0.3 percent of their revenues. For more information on the results of the analysis of small entity impacts, please refer to the economic impact analysis for the final amendments and new standards in Docket ID No. EPA–HQ–OAR–2006–0699.

*D. Unfunded Mandates Reform Act*

Title II of the Unfunded Mandates Reform Act (UMRA) of 1995, Public Law 104–4, establishes requirements for Federal agencies to assess the effects of their regulatory actions on State, local, and tribal governments and the private sector. Under section 202 of the UMRA, EPA generally must prepare a written statement, including a cost-benefit analysis, for proposed and final rules with "Federal mandates" that may result in expenditures by State, local, and tribal governments, in the aggregate, or to the private sector, of $100 million or more in any 1 year. Before promulgating an EPA rule for which a written statement is needed, section 205 of the UMRA generally requires EPA to identify and consider a reasonable number of regulatory alternatives and adopt the least costly, most cost-effective, or least burdensome alternative that achieves the objectives of the rule. The provisions of section 205 do not apply when they are inconsistent with applicable law. Moreover, section 205 allows EPA to adopt an alternative other than the least costly, most cost-effective, or least burdensome alternative if the Administrator publishes with the final rule an explanation why that alternative was not adopted.

Before EPA establishes any regulatory requirements that may significantly or uniquely affect small governments, including tribal governments, it must have developed under section 203 of the UMRA a small government agency plan. The plan must provide for notifying potentially affected small governments, enabling officials of affected small governments to have meaningful and timely input in the development of EPA regulatory proposals with significant Federal intergovernmental mandates, and informing, educating, and advising small governments on compliance with the regulatory requirements.

EPA has determined that this final action 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 1 year. As discussed earlier in this preamble, no costs are associated with the final amendments, which contain only clarifications, burden-reducing provisions, and new compliance options. For the new standards, the estimated annual expenditures for the private sector in the fifth year after proposal are $821,000 for SOCMI and $26,000 for petroleum refineries. Thus, the final amendments and the new standards are not subject to the requirements of sections 202 and 205 of the UMRA.

In addition, EPA has determined that the final action contains no regulatory requirements that might significantly or uniquely affect small governments. The 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 1 year or any disproportionate impacts on them. Therefore, the final action is not subject to the requirements of section 203 of the UMRA.

*E. Executive Order 13132: Federalism*

Executive Order 13132, entitled "Federalism" (64 FR 43255, August 10, 1999), requires EPA to develop an accountable process to ensure "meaningful and timely input by state and local officials in the development of

regulatory policies that have federalism implications." "Policies that have federalism implications" is defined in the Executive Order to include regulations that have "substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government."

The final action does not have federalism implications. The final amendments and the new standards 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 final action.

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

Executive Order 13175, entitled "Consultation and Coordination with Indian Tribal Governments" (65 FR 67249, November 9, 2000), requires EPA to develop an accountable process to ensure "meaningful and timely input by tribal officials in the development of regulatory policies that have tribal implications." The final action does not have tribal implications, as specified in Executive Order 13175. The final amendments and the new standards 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 final action.

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

Executive Order 13045, entitled "Protection of Children from Environmental Health Risks and Safety Risks" (62 FR 19885, April 23, 1997), applies to any rule that: (1) Is determined to be "economically significant" as defined under Executive Order 12866, and (2) concerns an environmental health or safety risk that EPA has reason to believe may have a disproportionate effect on children. If the regulatory action meets both criteria, the Agency must evaluate the environmental health or safety effects of the planned rule on children, and explain why the planned regulation is preferable to other potentially effective and reasonably feasible alternatives considered by the Agency.

EPA interprets Executive Order 13045 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 final action is not subject to Executive Order 13045 because the final amendments and the new standards are based on technology performance and not on health or safety risks.

*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, "Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use" (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 have concluded that this final action is not likely to have any adverse energy effects. The final action will not have any significant or adverse energy impacts because no additional pollution controls or other equipment that consume energy are required by the final amendments or new standards.

*I. National Technology Transfer and Advancement Act*

As noted in the proposal, section 12(d) of the National Technology Transfer and Advancement Act (NTTAA) of 1995 (Public Law No. 104–113, 12(d) (15 U.S.C. 272 note), directs EPA to use voluntary consensus standards (VCS) in its regulatory activities, unless to do so would be inconsistent with applicable law or otherwise impractical. VCS are technical standards (e.g., materials specifications, test methods, sampling procedures, and business practices) that are developed or adopted by VCS bodies. The NTTAA directs 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 cites the following methods: EPA Method 2, 2A, 2C, 2D, 18, 21, and 22 of 40 CFR part 60, appendix A.

In addition, the EPA cites the following ASTM methods that are also VCS: ASTM E260–73, E260–91, E260–96 (reapproved 2006), E168–67, E168–77, E168–92, E169–63, E169–77, and E169–93 when determining if a piece of equipment is in VOC service; ASTM D2879–83, D2879–96, and D2879–97 (reapproved 2007) when determining if a piece of equipment is in light liquid service, and ASTM D2504–67, D2504–77, D2504–88 (reapproved 1993), D2382–76, D2382–88, and D4809–95 when determining the maximum permitted velocity for air-assisted flares; ASTM E260–73, E260–91, E260–96, E168–67, E168–77, E168–92, E169–63, E169–77, and E169–93 when determining if a piece of equipment is in hydrogen service; and ASTM D86–78, D86–82, D86–90, D86–95, and D86–96 when determining if a piece of equipment is in light liquid service. These VCS will be incorporated by reference into § 60.17.

Consistent with the NTTAA, EPA conducted searches to identify VCS in addition to these EPA methods. No applicable VCS were identified for EPA Methods 2A, 2D, 21, and 22. The search and review results are in the docket for this rule.

The search identified one VCS as an acceptable alternative to an EPA Method. The standard ASTM D6420–99 (2004), "Test Method for Determination of Gaseous Organic Compounds by Direct Interface Gas Chromatography/Mass Spectrometry," is cited in this rule as an alternative to EPA Method 18 for measuring gaseous organic HAP.

Similar to EPA's performance-based Method 18, ASTM D6420–99 is also a performance-based method for measurement of gaseous organic compounds. However, ASTM D6420–99 was written to support the specific use of highly portable and automated gas chromatography (GC)/mass spectrometry (MS). While offering advantages over the traditional EPA Method 18, the ASTM method does allow some less stringent criteria for accepting GC/MS results than required by EPA Method 18. Therefore, 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.

As a result, EPA will cite ASTM D6420–99 in this rule. The EPA will also cite EPA Method 18 as a GC option in addition to ASTM D6420–99. This will allow the continued use of GC configurations other than GC/MS.

The search for emissions measurement procedures identified four other VCS. The EPA determined that these four standards identified for measuring emissions of the HAP or surrogates subject to emission standards in this rule were impractical alternatives to EPA test methods for the purposes of this rule. Therefore, EPA does not intend to adopt these standards for this purpose. The reasons for the determinations for the four methods are discussed in the docket to this rule.

A source may apply to EPA for permission to use alternative test methods or alternative monitoring requirements in place of any required testing methods, performance specifications, or procedures. Potential standards are reviewed to determine if they meet the requirements of EPA Method 301 for accepting alternative methods or scientific, engineering, and policy equivalence to procedures in EPA reference methods.

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

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

EPA has determined that this final action will not have disproportionately high and adverse human health or environmental effects on minority or low-income populations. The final amendments to the standards of performance for SOCMI (40 CFR part 60, subpart VV) and petroleum refineries (40 CFR part 60, subpart GGG) are comprised of clarifications, burden-reducing provisions, and new compliance options that do not affect the current level of control at facilities subject these rules. The new standards of performance for SOCMI (40 CFR part 60, subpart VVa) and petroleum refineries (40 CFR part 60, subpart GGGa) will increase 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 new subparts will increase the stringency of the standards of performance by reducing the leak definitions for certain pumps and valves, and subpart VVa will increase the stringency further by requiring the monitoring of certain connectors.

*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. EPA will submit a report containing this final action 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 action 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 is effective on November 16, 2007.

**List of Subjects**

*40 CFR Part 60*

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

*40 CFR Part 63*

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

Dated: October 31, 2007.

**Stephen L. Johnson,**

*Administrator.*

■ For the reasons cited in the preamble, title 40, chapter I, parts 60 and 63 of the Code of Federal Regulations are 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 paragraphs (a)(7), (35), (36), (41), (70), (88), (89), and (90) to read as follows:

**§ 60.17 Incorporations by reference.**

* * * * *

(a) * * *

(7) ASTM D86–78, 82, 90, 93, 95, 96, Distillation of Petroleum Products, IBR approved for §§ 60.562–2(d), 60.593(d), 60.593a(d), and 60.633(h).

* * * * *

(35) ASTM D2382–76, 88, Heat of Combustion of Hydrocarbon Fuels by Bomb Calorimeter (High-Precision Method), IBR approved for §§ 60.18(f)(3), 60.485(g)(6), 60.485a(g)(6), 60.564(f)(3), 60.614(e)(4), 60.664(e)(4), and 60.704(d)(4).

(36) ASTM D2504–67, 77, 88 (Reapproved 1993), Noncondensable Gases in C3 and Lighter Hydrocarbon Products by Gas Chromatography, IBR approved for §§ 60.485(g)(5) and 60.485a(g)(5).

* * * * *

(41) ASTM D2879–83, 96, 97, Test Method for Vapor Pressure-Temperature Relationship and Initial Decomposition Temperature of Liquids by Isoteniscope, IBR approved for §§ 60.111b(f)(3), 60.116b(e)(3)(ii), 60.116b(f)(2)(i), 60.485(e)(1), and 60.485a(e)(1).

* * * * *

(70) ASTM D4809–95, Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter (Precision Method), IBR approved for §§ 60.18(f)(3), 60.485(g)(6), 60.485a(g)(6), 60.564(f)(3), 60.614(d)(4), 60.664(e)(4), and 60.704(d)(4).

* * * * *

(88) ASTM E168–67, 77, 92, General Techniques of Infrared Quantitative Analysis, IBR approved for §§ 60.485a(d)(1), 60.593(b)(2), 60.593a(b)(2), and 60.632(f).

(89) ASTM E169–63, 77, 93, General Techniques of Ultraviolet Quantitative Analysis, IBR approved for §§ 60.485a(d)(1), 60.593(b)(2), 60.593a(b)(2), and 60.632(f).

(90) ASTM E260–73, 91, 96, General Gas Chromatography Procedures, IBR approved for §§ 60.485a(d)(1), 60.593(b)(2), 60.593a(b)(2), and 60.632(f).

* * * * *

**Subpart VV—Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry for which Construction, Reconstruction, or Modification Commenced After January 5, 1981, and on or Before November 7, 2006**

■ 3. The heading for Subpart VV is revised as set out above.

■ 4. Section 60.480 is amended by revising paragraphs (b), (d)(2) through (d)(5), and (e) to read as follows:

**§ 60.480 Applicability and designation of affected facility.**

* * * * *

(b) Any affected facility under paragraph (a) of this section that commences construction, reconstruction, or modification after January 5, 1981, and on or before November 7, 2006, shall be subject to the requirements of this subpart.

* * * * *

(d) * * *

(2) Any affected facility that has the design capacity to produce less than 1,000 Mg/yr (1,102 ton/yr) of a chemical listed in § 60.489 is exempt from §§ 60.482–1 through 60.482–10.

(3) If an affected facility produces heavy liquid chemicals only from heavy liquid feed or raw materials, then it is exempt from §§ 60.482–1 through 60.482–10.

(4) Any affected facility that produces beverage alcohol is exempt from §§ 60.482–1 through 60.482–10.

(5) Any affected facility that has no equipment in volatile organic compounds (VOC) service is exempt from §§ 60.482–1 through 60.482–10.

(e) *Alternative means of compliance*—(1) *Option to comply with part 65.* (i) Owners or operators may choose to comply with the provisions of 40 CFR part 65, subpart F, to satisfy the requirements of §§ 60.482 through 60.487 for an affected facility. When choosing to comply with 40 CFR part 65, subpart F, the requirements of § 60.485(d), (e), and (f) and § 60.486(i) and (j) still apply. Other provisions applying to an owner or operator who chooses to comply with 40 CFR part 65 are provided in 40 CFR 65.1.

(ii) *Part 60, subpart A.* Owners or operators who choose to comply with 40 CFR part 65, subpart F must also comply with §§ 60.1, 60.2, 60.5, 60.6, 60.7(a)(1) and (4), 60.14, 60.15, and 60.16 for that equipment. All sections and paragraphs of subpart A of this part that are not mentioned in this paragraph (e)(1)(ii) do not apply to owners and operators of equipment subject to this subpart complying with 40 CFR part 65, subpart F, except that provisions required to be met prior to implementing 40 CFR part 65 still apply. Owners and operators who choose to comply with 40 CFR part 65, subpart F, must comply with 40 CFR part 65, subpart A.

(2) *Subpart VVa.* Owners or operators may choose to comply with the provisions of subpart VVa of this part 60 to satisfy the requirements of this subpart VV for an affected facility.

■ 5. Section 60.481 is amended by:

■ a. In the definition of "Capital expenditure" remove the table heading in paragraph (a)(3) and add in its place the heading "Table for Determining Applicable Value for B";

■ b. Revising the definitions for the terms "Connector," "First attempt at repair," "Hard piping," "Process unit," "Process unit shutdown," and "Repaired"; and

■ c. Adding, in alphabetical order, new definitions for the terms "Closed-loop system," "Closed-purge system," "Storage vessel," and "Transfer rack" to read as follows:

**§ 60.481 Definitions.**

* * * * *

*Closed-loop system* means an enclosed system that returns process fluid to the process.

*Closed-purge system* means a system or combination of systems and portable containers to capture purged liquids. Containers for purged liquids must be covered or closed when not being filled or emptied.

* * * * *

*Connector* means flanged, screwed, or other joined fittings used to connect two pipe lines or a pipe line and a piece of process equipment or that close an opening in a pipe that could be connected to another pipe. Joined fittings welded completely around the circumference of the interface are not considered connectors for the purpose of this subpart.

* * * * *

*First attempt at repair* means to take action for the purpose of stopping or reducing leakage of organic material to the atmosphere using best practices.

* * * * *

*Hard-piping* means pipe or tubing that is manufactured and properly installed using good engineering judgment and standards such as ASME B31.3, Process Piping (available from the American Society of Mechanical Engineers, PO Box 2300, Fairfield, NJ 07007–2300).

* * * * *

*Process unit* means the components assembled and connected by pipes or ducts to process raw materials and to produce, as intermediate or final products, one or more of the chemicals listed in § 60.489. A process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the product. For the purpose of this subpart, process unit includes any feed, intermediate and final product storage vessels (except as specified in § 60.482–1(g)), product transfer racks, and connected ducts and piping. A process unit includes all equipment as defined in this subpart.

*Process unit shutdown* means a work practice or operational procedure that stops production from a process unit or part of a process unit during which it is technically feasible to clear process material from a process unit or part of a process unit consistent with safety constraints and during which repairs can be accomplished. The following are not considered process unit shutdowns:

(1) An unscheduled work practice or operational procedure that stops production from a process unit or part of a process unit for less than 24 hours.

(2) An unscheduled work practice or operational procedure that would stop production from a process unit or part of a process unit for a shorter period of time than would be required to clear the process unit or part of the process unit of materials and start up the unit, and would result in greater emissions than delay of repair of leaking components until the next scheduled process unit shutdown.

(3) The use of spare equipment and technically feasible bypassing of equipment without stopping production.

* * * * *

*Repaired* means that equipment is adjusted, or otherwise altered, in order to eliminate a leak as defined in the applicable sections of this subpart and, except for leaks identified in accordance with §§ 60.482–2(b)(2)(ii) and (d)(6)(ii) and (iii), 60.482–3(f), and 60.482–10(f)(1)(ii), is re-monitored as specified in § 60.485(b) to verify that emissions from the equipment are below the applicable leak definition.

* * * * *

*Storage vessel* means a tank or other vessel that is used to store organic liquids that are used in the process as raw material feedstocks, produced as intermediates or final products, or generated as wastes. Storage vessel does not include vessels permanently attached to motor vehicles, such as trucks, railcars, barges, or ships.

* * * * *

*Transfer rack* means the collection of loading arms and loading hoses, at a

single loading rack, that are used to fill tank trucks and/or railcars with organic liquids.

* * * * *

■ 6. Section 60.482–1 is amended by adding paragraphs (e), (f), and (g) to read as follows:

**§ 60.482–1 Standards: General.**

* * * * *

(e) Equipment that an owner or operator designates as being in VOC service less than 300 hours (hr)/yr is excluded from the requirements of §§ 60.482–2 through 60.482–10 if it is identified as required in § 60.486(e)(6) and it meets any of the conditions specified in paragraphs (e)(1) through (3) of this section.

(1) The equipment is in VOC service only during startup and shutdown, excluding startup and shutdown between batches of the same campaign for a batch process.

(2) The equipment is in VOC service only during process malfunctions or other emergencies.

(3) The equipment is backup equipment that is in VOC service only when the primary equipment is out of service.

(f)(1) If a dedicated batch process unit operates less than 365 days during a year, an owner or operator may monitor to detect leaks from pumps and valves at the frequency specified in the following table instead of monitoring as specified in §§ 60.482–2, 60.482–7, and 60.483–2:

| Operating time (percent of hours during year) | Equivalent monitoring frequency time in use | | |
|---|---|---|---|
| | Monthly | Quarterly | Semiannually |
| 0 to <25 | Quarterly | Annually | Annually. |
| 25 to <50 | Quarterly | Semiannually | Annually. |
| 50 to <75 | Bimonthly | Three quarters | Semiannually. |
| 75 to 100 | Monthly | Quarterly | Semiannually. |

(2) Pumps and valves that are shared among two or more batch process units that are subject to this subpart may be monitored at the frequencies specified in paragraph (f)(1) of this section, provided the operating time of all such process units is considered.

(3) The monitoring frequencies specified in paragraph (f)(1) of this section are not requirements for monitoring at specific intervals and can be adjusted to accommodate process operations. An owner or operator may monitor at any time during the specified monitoring period (e.g., month, quarter, year), provided the monitoring is conducted at a reasonable interval after completion of the last monitoring campaign. Reasonable intervals are defined in paragraphs (f)(3)(i) through (iv) of this section.

(i) When monitoring is conducted quarterly, monitoring events must be separated by at least 30 calendar days.

(ii) When monitoring is conducted semiannually (*i.e.*, once every 2 quarters), monitoring events must be separated by at least 60 calendar days.

(iii) When monitoring is conducted in 3 quarters per year, monitoring events must be separated by at least 90 calendar days.

(iv) When monitoring is conducted annually, monitoring events must be separated by at least 120 calendar days.

(g) If the storage vessel is shared with multiple process units, the process unit with the greatest annual amount of stored materials (predominant use) is the process unit the storage vessel is assigned to. If the storage vessel is shared equally among process units, and one of the process units has equipment subject to subpart VVa of this part, the storage vessel is assigned to that process unit. If the storage vessel is shared equally among process units, none of which have equipment subject to subpart VVa of this part, the storage vessel is assigned to any process unit subject to this subpart. If the predominant use of the storage vessel varies from year to year, then the owner or operator must estimate the predominant use initially and reassess every 3 years. The owner or operator must keep records of the information and supporting calculations that show how predominant use is determined. All equipment on the storage vessel must be monitored when in VOC service.

■ 7. Section 60.482–2 is amended by:

■ a. Revising paragraph (a);

■ b. Revising paragraph(b)(2);

■ c. Revising paragraph (c)(2);

■ d. Revising paragraphs (d) introductory text, (d)(1)(ii), (d)(4), (d)(5), and (d)(6); and

■ e. Revising paragraph (e) introductory text to read as follows:

**§ 60.482–2 Standards: Pumps in light liquid service.**

(a)(1) Each pump in light liquid service shall be monitored monthly to detect leaks by the methods specified in § 60.485(b), except as provided in § 60.482–1(c) and (f) and paragraphs (d), (e), and (f) of this section. A pump that begins operation in light liquid service after the initial startup date for the process unit must be monitored for the first time within 30 days after the end of its startup period, except for a pump that replaces a leaking pump and except as provided in § 60.482–1(c) and (f) and paragraphs (d), (c), and (f) of this section.

(2) Each pump in light liquid service shall be checked by visual inspection each calendar week for indications of liquids dripping from the pump seal, except as provided in § 60.482–1(f).

(b) * * *

(2) If there are indications of liquids dripping from the pump seal, the owner or operator shall follow the procedure specified in either paragraph (b)(2)(i) or (ii) of this section. This requirement does not apply to a pump that was monitored after a previous weekly inspection if the instrument reading for that monitoring event was less than 10,000 ppm and the pump was not repaired since that monitoring event.

(i) Monitor the pump within 5 days as specified in § 60.485(b). If an instrument reading of 10,000 ppm or greater is measured, a leak is detected. The leak shall be repaired using the procedures in paragraph (c) of this section.

(ii) Designate the visual indications of liquids dripping as a leak, and repair the leak within 15 days of detection by eliminating the visual indications of liquids dripping.

(c) * * *

(2) A first attempt at repair shall be made no later than 5 calendar days after each leak is detected. First attempts at repair include, but are not limited to, the practices described in paragraphs (c)(2)(i) and (ii) of this section, where practicable.

(i) Tightening the packing gland nuts;

(ii) Ensuring that the seal flush is operating at design pressure and temperature.

(d) Each pump equipped with a dual mechanical seal system that includes a barrier fluid system is exempt from the requirements of paragraph (a) of this section, provided the requirements specified in paragraphs (d)(1) through (6) of this section are met.

(1) * * *

(ii) Equipped with a barrier fluid degassing reservoir that is routed to a process or fuel gas system or connected by a closed vent system to a control device that complies with the requirements of § 60.482–10; or

* * * * *

(4)(i) Each pump is checked by visual inspection, each calendar week, for indications of liquids dripping from the pump seals.

(ii) If there are indications of liquids dripping from the pump seal at the time of the weekly inspection, the owner or operator shall follow the procedure specified in either paragraph (d)(4)(ii)(A) or (B) of this section.

(A) Monitor the pump within 5 days as specified in § 60.485(b) to determine if there is a leak of VOC in the barrier fluid. If an instrument reading of 10,000 ppm or greater is measured, a leak is detected.

(B) Designate the visual indications of liquids dripping as a leak.

(5)(i) Each sensor as described in paragraph (d)(3) of this section is checked daily or is equipped with an audible alarm.

(ii) The owner or operator determines, based on design considerations and operating experience, a criterion that indicates failure of the seal system, the barrier fluid system, or both.

(iii) If the sensor indicates failure of the seal system, the barrier fluid system, or both, based on the criterion established in paragraph (d)(5)(ii) of this section, a leak is detected.

(6)(i) When a leak is detected pursuant to paragraph (d)(4)(ii)(A) of this section, it shall be repaired as specified in paragraph (c) of this section.

(ii) A leak detected pursuant to paragraph (d)(5)(iii) of this section shall be repaired within 15 days of detection by eliminating the conditions that activated the sensor.

(iii) A designated leak pursuant to paragraph (d)(4)(ii)(B) of this section shall be repaired within 15 days of detection by eliminating visual indications of liquids dripping.

(e) Any pump that is designated, as described in § 60.486(e)(1) and (2), for no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, is exempt from the requirements of paragraphs (a), (c), and (d) of this section if the pump:

* * * * *

■ 8. Section 60.482–3 is amended by revising paragraphs (a) and (j) to read as follows:

**§ 60.482–3 Standards: Compressors.**

(a) Each compressor shall be equipped with a seal system that includes a barrier fluid system and that prevents leakage of VOC to the atmosphere, except as provided in § 60.482–1(c) and paragraphs (h), (i), and (j) of this section.

* * * * *

(j) Any existing reciprocating compressor in a process unit which becomes an affected facility under provisions of § 60.14 or § 60.15 is exempt from paragraphs (a) through (e) and (h) of this section, provided the owner or operator demonstrates that recasting the distance piece or replacing the compressor are the only options available to bring the compressor into compliance with the provisions of paragraphs (a) through (e) and (h) of this section.

■ 9. Section 60.482–5 is amended by revising paragraphs (a) and (b) to read as follows:

**§ 60.482–5 Standards: Sampling connection systems.**

(a) Each sampling connection system shall be equipped with a closed-purge, closed-loop, or closed-vent system, except as provided in § 60.482–1(c) and paragraph (c) of this section.

(b) Each closed-purge, closed-loop, or closed-vent system as required in paragraph (a) of this section shall comply with the requirements specified in paragraphs (b)(1) through (4) of this section.

(1) Gases displaced during filling of the sample container are not required to be collected or captured.

(2) Containers that are part of a closed-purge system must be covered or closed when not being filled or emptied.

(3) Gases remaining in the tubing or piping between the closed-purge system valve(s) and sample container valve(s) after the valves are closed and the sample container is disconnected are not required to be collected or captured.

(4) Each closed-purge, closed-loop, or closed-vent system shall be designed and operated to meet requirements in either paragraph (b)(4)(i), (ii), (iii), or (iv) of this section.

(i) Return the purged process fluid directly to the process line.

(ii) Collect and recycle the purged process fluid to a process.

(iii) Capture and transport all the purged process fluid to a control device that complies with the requirements of § 60.482–10.

(iv) Collect, store, and transport the purged process fluid to any of the following systems or facilities:

(A) A waste management unit as defined in § 63.111, if the waste management unit is subject to and operated in compliance with the provisions of 40 CFR part 63, subpart G, applicable to Group 1 wastewater streams;

(B) A treatment, storage, or disposal facility subject to regulation under 40 CFR part 262, 264, 265, or 266;

(C) A facility permitted, licensed, or registered by a state to manage municipal or industrial solid waste, if the process fluids are not hazardous waste as defined in 40 CFR part 261;

(D) A waste management unit subject to and operated in compliance with the treatment requirements of § 61.348(a), provided all waste management units that collect, store, or transport the purged process fluid to the treatment unit are subject to and operated in compliance with the management requirements of §§ 61.343 through 61.347; or

(E) A device used to burn off-specification used oil for energy recovery in accordance with 40 CFR part 279, subpart G, provided the purged process fluid is not hazardous waste as defined in 40 CFR part 261.

* * * * *

■ 10. Section 60.482–6 is amended by revising paragraph (a)(1) to read as follows:

**§ 60.482–6 Standards: Open-ended valves or lines.**

(a)(1) Each open-ended valve or line shall be equipped with a cap, blind flange, plug, or a second valve, except as provided in § 60.482–1(c) and paragraphs (d) and (e) of this section.

* * * * *

■ 11. Section 60.482–7 is amended by revising paragraphs (a) and (c)(1) to read as follows:

**§ 60.482–7 Standards: Valves in gas/vapor service and in light liquid service.**

(a)(1) Each valve shall be monitored monthly to detect leaks by the methods specified in § 60.485(b) and shall comply with paragraphs (b) through (e) of this section, except as provided in paragraphs (f), (g), and (h) of this section, § 60.482–1(c) and (f), and §§ 60.483–1 and 60.483–2.

(2) A valve that begins operation in gas/vapor service or light liquid service after the initial startup date for the process unit must be monitored according to paragraphs (a)(2)(i) or (ii), except for a valve that replaces a leaking valve and except as provided in paragraphs (f), (g), and (h) of this section, § 60.482–1(c), and §§ 60.483–1 and 60.483–2.

(i) Monitor the valve as in paragraph (a)(1) of this section. The valve must be

monitored for the first time within 30 days after the end of its startup period to ensure proper installation.

(ii) If the valves on the process unit are monitored in accordance with § 60.483–1 or § 60.483–2, count the new valve as leaking when calculating the percentage of valves leaking as described in § 60.483–2(b)(5). If less than 2.0 percent of the valves are leaking for that process unit, the valve must be monitored for the first time during the next scheduled monitoring event for existing valves in the process unit or within 90 days, whichever comes first.

* * * * *

(c)(1)(i) Any valve for which a leak is not detected for 2 successive months may be monitored the first month of every quarter, beginning with the next quarter, until a leak is detected.

(ii) As an alternative to monitoring all of the valves in the first month of a quarter, an owner or operator may elect to subdivide the process unit into 2 or 3 subgroups of valves and monitor each subgroup in a different month during the quarter, provided each subgroup is monitored every 3 months. The owner or operator must keep records of the valves assigned to each subgroup.

* * * * *

■ 12. Section 60.482–8 is amended by revising paragraphs (a)(2) and (d) to read as follows:

**§ 60.482–8 Standards: Pumps and valves in heavy liquid service, pressure relief devices in light liquid or heavy liquid service, and connectors.**

(a) * * *

(2) The owner or operator shall eliminate the visual, audible, olfactory, or other indication of a potential leak within 5 calendar days of detection.

* * * * *

(d) First attempts at repair include, but are not limited to, the best practices described under §§ 60.482–2(c)(2) and 60.482–7(e).

■ 13. Section 60.482–9 is amended by revising paragraph (a) and adding paragraph (f) to read as follows:

**§ 60.482–9 Standards: Delay of repair.**

(a) Delay of repair of equipment for which leaks have been detected will be allowed if repair within 15 days is technically infeasible without a process unit shutdown. Repair of this equipment shall occur before the end of the next process unit shutdown. Monitoring to verify repair must occur within 15 days after startup of the process unit.

* * * * *

(f) When delay of repair is allowed for a leaking pump or valve that remains in service, the pump or valve may be considered to be repaired and no longer subject to delay of repair requirements if two consecutive monthly monitoring instrument readings are below the leak definition.

■ 14. Section 60.483–1 is amended by revising paragraph (d) to read as follows:

**§ 60.483–1 Alternative standards for valves—allowable percentage of valves leaking.**

* * * * *

(d) Owners and operators who elect to comply with this alternative standard shall not have an affected facility with a leak percentage greater than 2.0 percent, determined as described in § 60.485(h).

■ 15. Section 60.483–2 is amended by revising paragraph (b)(5) and adding paragraph (b)(7) to read as follows:

**§ 60.483–2 Alternative standards for valves—skip period leak detection and repair.**

* * * * *

(b) * * *

(5) The percent of valves leaking shall be determined as described in § 60.485(h).

* * * * *

(7) A valve that begins operation in gas/vapor service or light liquid service after the initial startup date for a process unit following one of the alternative standards in this section must be monitored in accordance with § 60.482–7(a)(2)(i) or (ii) before the provisions of this section can be applied to that valve.

■ 16. Section 60.484 is amended by:

■ a. Removing the word "equivalance" and adding in its place the word "equivalence" in paragraph (a); and

■ b. Revising paragraph (b)(2) to read as follows:

**§ 60.484 Equivalence of means of emission limitation.**

* * * * *

(b) * * *

(2) The Administrator will compare test data for demonstrating equivalence of the means of emission limitation to test data for the equipment, design, and operational requirements.

* * * * *

■ 17. Section 60.485 is amended by:

■ a. Revising paragraph (b) introductory text;

■ b. Revising paragraphs (e) introductory text, (e)(1) and (e)(2);

■ c. Revising paragraphs (g)(4) and (5); and

■ d. Adding paragraph (h) to read as follows:

**§ 60.485 Test methods and procedures.**

* * * * *

(b) The owner or operator shall determine compliance with the standards in §§ 60.482–1 through 60.482–10, 60.483, and 60.484 as follows:

* * * * *

(e) The owner or operator shall demonstrate that a piece of equipment is in light liquid service by showing that all the following conditions apply:

(1) The vapor pressure of one or more of the organic components is greater than 0.3 kPa at 20 °C (1.2 in. $H_2O$ at 68 °F). Standard reference texts or ASTM D2879–83, 96, or 97 (incorporated by reference—see § 60.17) shall be used to determine the vapor pressures.

(2) The total concentration of the pure organic components having a vapor pressure greater than 0.3 kPa at 20 °C (1.2 in. $H_2O$ at 68 °F) is equal to or greater than 20 percent by weight.

* * * * *

(g) * * *

(4) The net heating value ($H_T$) of the gas being combusted in a flare shall be computed using the following equation:

$$H_T = K\sum_{i=1}^{n} C_i H_i$$

Where:

K = Conversion constant, $1.740 \times 10^{-7}$ (g-mole)(MJ)/(ppm-scm-kcal) (metric units) = $4.674 \times 10^{-6}$ [(g-mole)(Btu)/(ppm-scf-kcal)] (English units)

$C_i$ = Concentration of sample component "i," ppm

$H_i$ = Net heat of combustion of sample component "i" at 25 °C and 760 mm Hg (77 °F and 14.7 psi), kcal/g-mole

(5) Method 18 or ASTM D6420–99 (2004) (where the target compound(s) are those listed in Section 1.1 of ASTM D6420–99, and the target concentration is between 150 parts per billion by volume and 100 parts per million by volume) and ASTM D2504–67, 77 or 88 (Reapproved 1993) (incorporated by reference—see § 60.17) shall be used to determine the concentration of sample component "i."

* * * * *

(h) The owner or operator shall determine compliance with § 60.483–1 or § 60.483–2 as follows:

(1) The percent of valves leaking shall be determined using the following equation:

$$\%V_L = (V_L/V_T) * 100$$

Where:

$\%V_L$ = Percent leaking valves

$V_L$ = Number of valves found leaking

$V_T$ = The sum of the total number of valves monitored

(2) The total number of valves monitored shall include difficult-to-monitor and unsafe-to-monitor valves

only during the monitoring period in which those valves are monitored.

(3) The number of valves leaking shall include valves for which repair has been delayed.

(4) Any new valve that is not monitored within 30 days of being placed in service shall be included in the number of valves leaking and the total number of valves monitored for the monitoring period in which the valve is placed in service.

(5) If the process unit has been subdivided in accordance with § 60.482–7(c)(1)(ii), the sum of valves found leaking during a monitoring period includes all subgroups.

(6) The total number of valves monitored does not include a valve monitored to verify repair.

■ 18. Section 60.486 is amended by revising paragraph (e)(2)(ii) and adding paragraph (e)(6) to read as follows:

**§ 60.486 Recordkeeping requirements.**

* * * * *

(e) * * *

(2) * * *

(ii) The designation of equipment as subject to the requirements of § 60.482–2(e), § 60.482–3(i), or § 60.482–7(f) shall be signed by the owner or operator. Alternatively, the owner or operator may establish a mechanism with their permitting authority that satisfies this requirement.

* * * * *

(6) A list of identification numbers for equipment that the owner or operator designates as operating in VOC service less than 300 hr/yr in accordance with § 60.482–1(e), a description of the conditions under which the equipment is in VOC service, and rationale supporting the designation that it is in VOC service less than 300 hr/yr.

* * * * *

■ 19. Section 60.487 is amended by:

■ a. Revising paragraphs (c)(2)(i), (c)(2)(iii), and (c)(2)(iv) to read as follows:

**§ 60.487 Reporting requirements.**

* * * * *

(c) * * *

(2) * * *

(i) Number of valves for which leaks were detected as described in § 60.482–7(b) or § 60.483–2,

* * * * *

(iii) Number of pumps for which leaks were detected as described in § 60.482–2(b), (d)(4)(ii)(A) or (B), or (d)(5)(iii),

(iv) Number of pumps for which leaks were not repaired as required in § 60.482–2(c)(1) and (d)(6),

* * * * *

■ 20. Part 60 is amended by adding subpart VVa to read as follows:

## Subpart VVa—Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006

Sec.



**§ 60.480a Applicability and designation of affected facility.**

(a)(1) The provisions of this subpart apply to affected facilities in the synthetic organic chemicals manufacturing industry.

(2) The group of all equipment (defined in § 60.481a) within a process unit is an affected facility.

(b) Any affected facility under paragraph (a) of this section that commences construction, reconstruction, or modification after November 7, 2006, shall be subject to the requirements of this subpart.

(c) Addition or replacement of equipment for the purpose of process improvement which is accomplished without a capital expenditure shall not by itself be considered a modification under this subpart.

(d)(1) If an owner or operator applies for one or more of the exemptions in this paragraph, then the owner or operator shall maintain records as required in § 60.486a(i).

(2) Any affected facility that has the design capacity to produce less than 1,000 Mg/yr (1,102 ton/yr) of a chemical listed in § 60.489 is exempt from §§ 60.482–1a through 60.482–11a.

(3) If an affected facility produces heavy liquid chemicals only from heavy liquid feed or raw materials, then it is exempt from §§ 60.482–1a through 60.482–11a.

(4) Any affected facility that produces beverage alcohol is exempt from §§ 60.482–1a through 60.482–11a.

(5) Any affected facility that has no equipment in volatile organic compounds (VOC) service is exempt from §§ 60.482–1a through 60.482–11a.

(e) *Alternative means of compliance*—(1) *Option to comply with part 65.* (i) Owners or operators may choose to comply with the provisions of 40 CFR part 65, subpart F, to satisfy the requirements of §§ 60.482–1a through 60.487a for an affected facility. When choosing to comply with 40 CFR part 65, subpart F, the requirements of §§ 60.485a(d), (e), and (f), and 60.486a(i) and (j) still apply. Other provisions applying to an owner or operator who chooses to comply with 40 CFR part 65 are provided in 40 CFR 65.1.

(ii) *Part 60, subpart A.* Owners or operators who choose to comply with 40 CFR part 65, subpart F must also comply with §§ 60.1, 60.2, 60.5, 60.6, 60.7(a)(1) and (4), 60.14, 60.15, and 60.16 for that equipment. All sections and paragraphs of subpart A of this part that are not mentioned in this paragraph (e)(1)(ii) do not apply to owners or operators of equipment subject to this subpart complying with 40 CFR part 65, subpart F, except that provisions required to be met prior to implementing 40 CFR part 65 still apply. Owners and operators who choose to comply with 40 CFR part 65, subpart F, must comply with 40 CFR part 65, subpart A.

(2) *Part 63, subpart H.* (i) Owners or operators may choose to comply with the provisions of 40 CFR part 63, subpart H, to satisfy the requirements of §§ 60.482–1a through 60.487a for an affected facility. When choosing to comply with 40 CFR part 63, subpart H, the requirements of § 60.485a(d), (e), and (f), and § 60.486a(i) and (j) still apply.

(ii) *Part 60, subpart A.* Owners or operators who choose to comply with 40 CFR part 63, subpart H must also comply with §§ 60.1, 60.2, 60.5, 60.6, 60.7(a)(1) and (4), 60.14, 60.15, and 60.16 for that equipment. All sections and paragraphs of subpart A of this part that are not mentioned in this paragraph (e)(2)(ii) do not apply to owners or operators of equipment subject to this

subpart complying with 40 CFR part 63, subpart H, except that provisions required to be met prior to implementing 40 CFR part 63 still apply. Owners and operators who choose to comply with 40 CFR part 63, subpart H, must comply with 40 CFR part 63, subpart A.

**§ 60.481a Definitions.**

As used in this subpart, all terms not defined herein shall have the meaning given them in the Clean Air Act (CAA) or in subpart A of part 60, and the following terms shall have the specific meanings given them.

*Capital expenditure* means, in addition to the definition in 40 CFR 60.2, an expenditure for a physical or operational change to an existing facility that:

(a) Exceeds P, the product of the facility's replacement cost, R, and an adjusted annual asset guideline repair allowance, A, as reflected by the following equation: $P = R \times A$, where:

(1) The adjusted annual asset guideline repair allowance, A, is the product of the percent of the replacement cost, Y, and the applicable basic annual asset guideline repair allowance, B, divided by 100 as reflected by the following equation:

$A = Y \times (B \div 100)$;

(2) The percent Y is determined from the following equation: $Y = 1.0 - 0.575 \log X$, where X is 2006 minus the year of construction; and

(3) The applicable basic annual asset guideline repair allowance, B, is selected from the following table consistent with the applicable subpart:

TABLE FOR DETERMINING APPLICABLE VALUE FOR B

| Subpart applicable to facility | Value of B to be used in equation |
|---|---|
| VVa | 12.5 |
| GGGa | 7.0 |

*Closed-loop system* means an enclosed system that returns process fluid to the process.

*Closed-purge system* means a system or combination of systems and portable containers to capture purged liquids. Containers for purged liquids must be covered or closed when not being filled or emptied.

*Closed vent system* means a system that is not open to the atmosphere and that is composed of hard-piping, ductwork, connections, and, if necessary, flow-inducing devices that transport gas or vapor from a piece or pieces of equipment to a control device or back to a process.

*Connector* means flanged, screwed, or other joined fittings used to connect two pipe lines or a pipe line and a piece of process equipment or that close an opening in a pipe that could be connected to another pipe. Joined fittings welded completely around the circumference of the interface are not considered connectors for the purpose of this regulation.

*Control device* means an enclosed combustion device, vapor recovery system, or flare.

*Distance piece* means an open or enclosed casing through which the piston rod travels, separating the compressor cylinder from the crankcase.

*Double block and bleed system* means two block valves connected in series with a bleed valve or line that can vent the line between the two block valves.

*Duct work* means a conveyance system such as those commonly used for heating and ventilation systems. It is often made of sheet metal and often has sections connected by screws or crimping. Hard-piping is not ductwork.

*Equipment* means each pump, compressor, pressure relief device, sampling connection system, open-ended valve or line, valve, and flange or other connector in VOC service and any devices or systems required by this subpart.

*First attempt at repair* means to take action for the purpose of stopping or reducing leakage of organic material to the atmosphere using best practices.

*Fuel gas* means gases that are combusted to derive useful work or heat.

*Fuel gas system* means the offsite and onsite piping and flow and pressure control system that gathers gaseous stream(s) generated by onsite operations, may blend them with other sources of gas, and transports the gaseous stream for use as fuel gas in combustion devices or in-process combustion equipment, such as furnaces and gas turbines, either singly or in combination.

*Hard-piping* means pipe or tubing that is manufactured and properly installed using good engineering judgment and standards such as ASME B31.3, Process Piping (available from the American Society of Mechanical Engineers, P.O. Box 2300, Fairfield, NJ 07007–2300).

*In gas/vapor service* means that the piece of equipment contains process fluid that is in the gaseous state at operating conditions.

*In heavy liquid service* means that the piece of equipment is not in gas/vapor service or in light liquid service.

*In light liquid service* means that the piece of equipment contains a liquid that meets the conditions specified in § 60.485a(e).

*In-situ sampling systems* means nonextractive samplers or in-line samplers.

*In vacuum service* means that equipment is operating at an internal pressure which is at least 5 kilopascals (kPa) (0.7 psia) below ambient pressure.

*In VOC service* means that the piece of equipment contains or contacts a process fluid that is at least 10 percent VOC by weight. (The provisions of § 60.485a(d) specify how to determine that a piece of equipment is not in VOC service.)

*Initial calibration value* means the concentration measured during the initial calibration at the beginning of each day required in § 60.485a(b)(1), or the most recent calibration if the instrument is recalibrated during the day (i.e., the calibration is adjusted) after a calibration drift assessment.

*Liquids dripping* means any visible leakage from the seal including spraying, misting, clouding, and ice formation.

*Open-ended valve or line* means any valve, except safety relief valves, having one side of the valve seat in contact with process fluid and one side open to the atmosphere, either directly or through open piping.

*Pressure release means* the emission of materials resulting from system pressure being greater than set pressure of the pressure relief device.

*Process improvement* means routine changes made for safety and occupational health requirements, for energy savings, for better utility, for ease of maintenance and operation, for correction of design deficiencies, for bottleneck removal, for changing product requirements, or for environmental control.

*Process unit* means the components assembled and connected by pipes or ducts to process raw materials and to produce, as intermediate or final products, one or more of the chemicals listed in § 60.489. A process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the product. For the purpose of this subpart, process unit includes any feed, intermediate and final product storage vessels (except as specified in § 60.482–1a(g)), product transfer racks, and connected ducts and piping. A process unit includes all equipment as defined in this subpart.

*Process unit shutdown* means a work practice or operational procedure that stops production from a process unit or part of a process unit during which it is technically feasible to clear process

material from a process unit or part of a process unit consistent with safety constraints and during which repairs can be accomplished. The following are not considered process unit shutdowns:

(1) An unscheduled work practice or operational procedure that stops production from a process unit or part of a process unit for less than 24 hours.

(2) An unscheduled work practice or operational procedure that would stop production from a process unit or part of a process unit for a shorter period of time than would be required to clear the process unit or part of the process unit of materials and start up the unit, and would result in greater emissions than delay of repair of leaking components until the next scheduled process unit shutdown.

(3) The use of spare equipment and technically feasible bypassing of equipment without stopping production.

*Quarter* means a 3-month period; the first quarter concludes on the last day of the last full month during the 180 days following initial startup.

*Repaired* means that equipment is adjusted, or otherwise altered, in order to eliminate a leak as defined in the applicable sections of this subpart and, except for leaks identified in accordance with §§ 60.482–2a(b)(2)(ii) and (d)(6)(ii) and (d)(6)(iii), 60.482–3a(f), and 60.482–10a(f)(1)(ii), is re-monitored as specified in § 60.485a(b) to verify that emissions from the equipment are below the applicable leak definition.

*Replacement cost* means the capital needed to purchase all the depreciable components in a facility.

*Sampling connection system* means an assembly of equipment within a process unit used during periods of representative operation to take samples of the process fluid. Equipment used to take nonroutine grab samples is not considered a sampling connection system.

*Sensor* means a device that measures a physical quantity or the change in a physical quantity such as temperature, pressure, flow rate, pH, or liquid level.

*Storage vessel* means a tank or other vessel that is used to store organic liquids that are used in the process as raw material feedstocks, produced as intermediates or final products, or generated as wastes. Storage vessel does not include vessels permanently attached to motor vehicles, such as trucks, railcars, barges or ships.

*Synthetic organic chemicals manufacturing industry* means the industry that produces, as intermediates or final products, one or more of the chemicals listed in § 60.489.

*Transfer rack* means the collection of loading arms and loading hoses, at a single loading rack, that are used to fill tank trucks and/or railcars with organic liquids.

*Volatile organic compounds* or VOC means, for the purposes of this subpart, any reactive organic compounds as defined in § 60.2 Definitions.

**§ 60.482–1a Standards: General.**

(a) Each owner or operator subject to the provisions of this subpart shall demonstrate compliance with the requirements of §§ 60.482–1a through 60.482–10a or § 60.480a(e) for all equipment within 180 days of initial startup.

(b) Compliance with §§ 60.482–1a to 60.482–10a will be determined by review of records and reports, review of performance test results, and inspection using the methods and procedures specified in § 60.485a.

(c)(1) An owner or operator may request a determination of equivalence of a means of emission limitation to the requirements of §§ 60.482–2a, 60.482–3a, 60.482–5a, 60.482–6a, 60.482–7a, 60.482–8a, and 60.482–10a as provided in § 60.484a.

(2) If the Administrator makes a determination that a means of emission limitation is at least equivalent to the requirements of §§ 60.482–2a, 60.482–3a, 60.482–5a, 60.482–6a, 60.482–7a, 60.482–8a, or 60.482–10a, an owner or operator shall comply with the requirements of that determination.

(d) Equipment that is in vacuum service is excluded from the requirements of §§ 60.482–2a through 60.482–10a if it is identified as required in § 60.486a(e)(5).

(e) Equipment that an owner or operator designates as being in VOC service less than 300 hr/yr is excluded from the requirements of §§ 60.482–2a through 60.482–11a if it is identified as required in § 60.486a(e)(6) and it meets any of the conditions specified in paragraphs (e)(1) through (3) of this section.

(1) The equipment is in VOC service only during startup and shutdown, excluding startup and shutdown between batches of the same campaign for a batch process.

(2) The equipment is in VOC service only during process malfunctions or other emergencies.

(3) The equipment is backup equipment that is in VOC service only when the primary equipment is out of service.

(f)(1) If a dedicated batch process unit operates less than 365 days during a year, an owner or operator may monitor to detect leaks from pumps, valves, and open-ended valves or lines at the frequency specified in the following table instead of monitoring as specified in §§ 60.482–2a, 60.482–7a, and 60.483.2a:

| Operating time (percent of hours during year) | Equivalent monitoring frequency time in use | | |
|---|---|---|---|
| | Monthly | Quarterly | Semiannually |
| 0 to <25 | Quarterly | Annually | Annually. |
| 25 to <50 | Quarterly | Semiannually | Annually. |
| 50 to <75 | Bimonthly | Three quarters | Semiannually. |
| 75 to 100 | Monthly | Quarterly | Semiannually. |

(2) Pumps and valves that are shared among two or more batch process units that are subject to this subpart may be monitored at the frequencies specified in paragraph (f)(1) of this section, provided the operating time of all such process units is considered.

(3) The monitoring frequencies specified in paragraph (f)(1) of this section are not requirements for monitoring at specific intervals and can be adjusted to accommodate process operations. An owner or operator may monitor at any time during the specified monitoring period (e.g., month, quarter, year), provided the monitoring is conducted at a reasonable interval after completion of the last monitoring campaign. Reasonable intervals are defined in paragraphs (f)(3)(i) through (iv) of this section.

(i) When monitoring is conducted quarterly, monitoring events must be separated by at least 30 calendar days.

(ii) When monitoring is conducted semiannually (*i.e.*, once every 2 quarters), monitoring events must be separated by at least 60 calendar days.

(iii) When monitoring is conducted in 3 quarters per year, monitoring events

must be separated by at least 90 calendar days.

(iv) When monitoring is conducted annually, monitoring events must be separated by at least 120 calendar days.

(g) If the storage vessel is shared with multiple process units, the process unit with the greatest annual amount of stored materials (predominant use) is the process unit the storage vessel is assigned to. If the storage vessel is shared equally among process units, and one of the process units has equipment subject to this subpart, the storage vessel is assigned to that process unit. If the storage vessel is shared equally among process units, none of which have equipment subject to this subpart of this part, the storage vessel is assigned to any process unit subject to subpart VV of this part. If the predominant use of the storage vessel varies from year to year, then the owner or operator must estimate the predominant use initially and reassess every 3 years. The owner or operator must keep records of the information and supporting calculations that show how predominant use is determined. All equipment on the storage vessel must be monitored when in VOC service.

**§ 60.482–2a Standards: Pumps in light liquid service.**

(a)(1) Each pump in light liquid service shall be monitored monthly to detect leaks by the methods specified in § 60.485a(b), except as provided in § 60.482–1a(c) and (f) and paragraphs (d), (e), and (f) of this section. A pump that begins operation in light liquid service after the initial startup date for the process unit must be monitored for the first time within 30 days after the end of its startup period, except for a pump that replaces a leaking pump and except as provided in § 60.482–1a(c) and paragraphs (d), (e), and (f) of this section.

(2) Each pump in light liquid service shall be checked by visual inspection each calendar week for indications of liquids dripping from the pump seal, except as provided in § 60.482–1a(f).

(b)(1) The instrument reading that defines a leak is specified in paragraphs (b)(1)(i) and (ii) of this section.

(i) 5,000 parts per million (ppm) or greater for pumps handling polymerizing monomers;

(ii) 2,000 ppm or greater for all other pumps.

(2) If there are indications of liquids dripping from the pump seal, the owner or operator shall follow the procedure specified in either paragraph (b)(2)(i) or (ii) of this section. This requirement does not apply to a pump that was monitored after a previous weekly inspection and the instrument reading was less than the concentration specified in paragraph (b)(1)(i) or (ii) of this section, whichever is applicable.

(i) Monitor the pump within 5 days as specified in § 60.485a(b). A leak is detected if the instrument reading measured during monitoring indicates a leak as specified in paragraph (b)(1)(i) or (ii) of this section, whichever is applicable. The leak shall be repaired using the procedures in paragraph (c) of this section.

(ii) Designate the visual indications of liquids dripping as a leak, and repair the leak using either the procedures in paragraph (c) of this section or by eliminating the visual indications of liquids dripping.

(c)(1) When a leak is detected, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in § 60.482–9a.

(2) A first attempt at repair shall be made no later than 5 calendar days after each leak is detected. First attempts at repair include, but are not limited to, the practices described in paragraphs (c)(2)(i) and (ii) of this section, where practicable.

(i) Tightening the packing gland nuts;

(ii) Ensuring that the seal flush is operating at design pressure and temperature.

(d) Each pump equipped with a dual mechanical seal system that includes a barrier fluid system is exempt from the requirements of paragraph (a) of this section, provided the requirements specified in paragraphs (d)(1) through (6) of this section are met.

(1) Each dual mechanical seal system is:

(i) Operated with the barrier fluid at a pressure that is at all times greater than the pump stuffing box pressure; or

(ii) Equipped with a barrier fluid degassing reservoir that is routed to a process or fuel gas system or connected by a closed vent system to a control device that complies with the requirements of § 60.482–10a; or

(iii) Equipped with a system that purges the barrier fluid into a process stream with zero VOC emissions to the atmosphere.

(2) The barrier fluid system is in heavy liquid service or is not in VOC service.

(3) Each barrier fluid system is equipped with a sensor that will detect failure of the seal system, the barrier fluid system, or both.

(4)(i) Each pump is checked by visual inspection, each calendar week, for indications of liquids dripping from the pump seals.

(ii) If there are indications of liquids dripping from the pump seal at the time of the weekly inspection, the owner or operator shall follow the procedure specified in either paragraph (d)(4)(ii)(A) or (B) of this section prior to the next required inspection.

(A) Monitor the pump within 5 days as specified in § 60.485a(b) to determine if there is a leak of VOC in the barrier fluid. If an instrument reading of 2,000 ppm or greater is measured, a leak is detected.

(B) Designate the visual indications of liquids dripping as a leak.

(5)(i) Each sensor as described in paragraph (d)(3) is checked daily or is equipped with an audible alarm.

(ii) The owner or operator determines, based on design considerations and operating experience, a criterion that indicates failure of the seal system, the barrier fluid system, or both.

(iii) If the sensor indicates failure of the seal system, the barrier fluid system, or both, based on the criterion established in paragraph (d)(5)(ii) of this section, a leak is detected.

(6)(i) When a leak is detected pursuant to paragraph (d)(4)(ii)(A) of this section, it shall be repaired as specified in paragraph (c) of this section.

(ii) A leak detected pursuant to paragraph (d)(5)(iii) of this section shall be repaired within 15 days of detection by eliminating the conditions that activated the sensor.

(iii) A designated leak pursuant to paragraph (d)(4)(ii)(B) of this section shall be repaired within 15 days of detection by eliminating visual indications of liquids dripping.

(e) Any pump that is designated, as described in § 60.486a(e)(1) and (2), for no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, is exempt from the requirements of paragraphs (a), (c), and (d) of this section if the pump:

(1) Has no externally actuated shaft penetrating the pump housing;

(2) Is demonstrated to be operating with no detectable emissions as indicated by an instrument reading of less than 500 ppm above background as measured by the methods specified in § 60.485a(c); and

(3) Is tested for compliance with paragraph (e)(2) of this section initially upon designation, annually, and at other times requested by the Administrator.

(f) If any pump is equipped with a closed vent system capable of capturing and transporting any leakage from the seal or seals to a process or to a fuel gas system or to a control device that complies with the requirements of § 60.482–10a, it is exempt from

paragraphs (a) through (e) of this section.

(g) Any pump that is designated, as described in § 60.486a(f)(1), as an unsafe-to-monitor pump is exempt from the monitoring and inspection requirements of paragraphs (a) and (d)(4) through (6) of this section if:

(1) The owner or operator of the pump demonstrates that the pump is unsafe-to-monitor because monitoring personnel would be exposed to an immediate danger as a consequence of complying with paragraph (a) of this section; and

(2) The owner or operator of the pump has a written plan that requires monitoring of the pump as frequently as practicable during safe-to-monitor times, but not more frequently than the periodic monitoring schedule otherwise applicable, and repair of the equipment according to the procedures in paragraph (c) of this section if a leak is detected.

(h) Any pump that is located within the boundary of an unmanned plant site is exempt from the weekly visual inspection requirement of paragraphs (a)(2) and (d)(4) of this section, and the daily requirements of paragraph (d)(5) of this section, provided that each pump is visually inspected as often as practicable and at least monthly.

**§ 60.482–3a Standards: Compressors.**

(a) Each compressor shall be equipped with a seal system that includes a barrier fluid system and that prevents leakage of VOC to the atmosphere, except as provided in § 60.482–1a(c) and paragraphs (h), (i), and (j) of this section.

(b) Each compressor seal system as required in paragraph (a) of this section shall be:

(1) Operated with the barrier fluid at a pressure that is greater than the compressor stuffing box pressure; or

(2) Equipped with a barrier fluid system degassing reservoir that is routed to a process or fuel gas system or connected by a closed vent system to a control device that complies with the requirements of § 60.482–10a; or

(3) Equipped with a system that purges the barrier fluid into a process stream with zero VOC emissions to the atmosphere.

(c) The barrier fluid system shall be in heavy liquid service or shall not be in VOC service.

(d) Each barrier fluid system as described in paragraph (a) shall be equipped with a sensor that will detect failure of the seal system, barrier fluid system, or both.

(e)(1) Each sensor as required in paragraph (d) of this section shall be checked daily or shall be equipped with an audible alarm.

(2) The owner or operator shall determine, based on design considerations and operating experience, a criterion that indicates failure of the seal system, the barrier fluid system, or both.

(f) If the sensor indicates failure of the seal system, the barrier system, or both based on the criterion determined under paragraph (e)(2) of this section, a leak is detected.

(g)(1) When a leak is detected, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in § 60.482–9a.

(2) A first attempt at repair shall be made no later than 5 calendar days after each leak is detected.

(h) A compressor is exempt from the requirements of paragraphs (a) and (b) of this section, if it is equipped with a closed vent system to capture and transport leakage from the compressor drive shaft back to a process or fuel gas system or to a control device that complies with the requirements of § 60.482–10a, except as provided in paragraph (i) of this section.

(i) Any compressor that is designated, as described in § 60.486a(e)(1) and (2), for no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, is exempt from the requirements of paragraphs (a) through (h) of this section if the compressor:

(1) Is demonstrated to be operating with no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as measured by the methods specified in § 60.485a(c); and

(2) Is tested for compliance with paragraph (i)(1) of this section initially upon designation, annually, and at other times requested by the Administrator.

(j) Any existing reciprocating compressor in a process unit which becomes an affected facility under provisions of § 60.14 or § 60.15 is exempt from paragraphs (a) through (e) and (h) of this section, provided the owner or operator demonstrates that recasting the distance piece or replacing the compressor are the only options available to bring the compressor into compliance with the provisions of paragraphs (a) through (e) and (h) of this section.

**§ 60.482–4a Standards: Pressure relief devices in gas/vapor service.**

(a) Except during pressure releases, each pressure relief device in gas/vapor service shall be operated with no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as determined by the methods specified in § 60.485a(c).

(b)(1) After each pressure release, the pressure relief device shall be returned to a condition of no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as soon as practicable, but no later than 5 calendar days after the pressure release, except as provided in § 60.482–9a.

(2) No later than 5 calendar days after the pressure release, the pressure relief device shall be monitored to confirm the conditions of no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, by the methods specified in § 60.485a(c).

(c) Any pressure relief device that is routed to a process or fuel gas system or equipped with a closed vent system capable of capturing and transporting leakage through the pressure relief device to a control device as described in § 60.482–10a is exempted from the requirements of paragraphs (a) and (b) of this section.

(d)(1) Any pressure relief device that is equipped with a rupture disk upstream of the pressure relief device is exempt from the requirements of paragraphs (a) and (b) of this section, provided the owner or operator complies with the requirements in paragraph (d)(2) of this section.

(2) After each pressure release, a new rupture disk shall be installed upstream of the pressure relief device as soon as practicable, but no later than 5 calendar days after each pressure release, except as provided in § 60.482–9a.

**§ 60.482–5a Standards: Sampling connection systems.**

(a) Each sampling connection system shall be equipped with a closed-purge, closed-loop, or closed-vent system, except as provided in § 60.482–1a(c) and paragraph (c) of this section.

(b) Each closed-purge, closed-loop, or closed-vent system as required in paragraph (a) of this section shall comply with the requirements specified in paragraphs (b)(1) through (4) of this section.

(1) Gases displaced during filling of the sample container are not required to be collected or captured.

(2) Containers that are part of a closed-purge system must be covered or closed when not being filled or emptied.

(3) Gases remaining in the tubing or piping between the closed-purge system valve(s) and sample container valve(s) after the valves are closed and the sample container is disconnected are not required to be collected or captured.

(4) Each closed-purge, closed-loop, or closed-vent system shall be designed and operated to meet requirements in either paragraph (b)(4)(i), (ii), (iii), or (iv) of this section.

(i) Return the purged process fluid directly to the process line.

(ii) Collect and recycle the purged process fluid to a process.

(iii) Capture and transport all the purged process fluid to a control device that complies with the requirements of § 60.482–10a.

(iv) Collect, store, and transport the purged process fluid to any of the following systems or facilities:

(A) A waste management unit as defined in 40 CFR 63.111, if the waste management unit is subject to and operated in compliance with the provisions of 40 CFR part 63, subpart G, applicable to Group 1 wastewater streams;

(B) A treatment, storage, or disposal facility subject to regulation under 40 CFR part 262, 264, 265, or 266;

(C) A facility permitted, licensed, or registered by a state to manage municipal or industrial solid waste, if the process fluids are not hazardous waste as defined in 40 CFR part 261;

(D) A waste management unit subject to and operated in compliance with the treatment requirements of 40 CFR 61.348(a), provided all waste management units that collect, store, or transport the purged process fluid to the treatment unit are subject to and operated in compliance with the management requirements of 40 CFR 61.343 through 40 CFR 61.347; or

(E) A device used to burn off-specification used oil for energy recovery in accordance with 40 CFR part 279, subpart G, provided the purged process fluid is not hazardous waste as defined in 40 CFR part 261.

(c) In-situ sampling systems and sampling systems without purges are exempt from the requirements of paragraphs (a) and (b) of this section.

**§ 60.482–6a Standards: Open-ended valves or lines.**

(a)(1) Each open-ended valve or line shall be equipped with a cap, blind flange, plug, or a second valve, except as provided in § 60.482–1a(c) and paragraphs (d) and (e) of this section.

(2) The cap, blind flange, plug, or second valve shall seal the open end at all times except during operations requiring process fluid flow through the open-ended valve or line.

(b) Each open-ended valve or line equipped with a second valve shall be operated in a manner such that the valve on the process fluid end is closed before the second valve is closed.

(c) When a double block-and-bleed system is being used, the bleed valve or line may remain open during operations that require venting the line between the block valves but shall comply with paragraph (a) of this section at all other times.

(d) Open-ended valves or lines in an emergency shutdown system which are designed to open automatically in the event of a process upset are exempt from the requirements of paragraphs (a), (b), and (c) of this section.

(e) Open-ended valves or lines containing materials which would autocatalytically polymerize or would present an explosion, serious overpressure, or other safety hazard if capped or equipped with a double block and bleed system as specified in paragraphs (a) through (c) of this section are exempt from the requirements of paragraphs (a) through (c) of this section.

**§ 60.482–7a Standards: Valves in gas/vapor service and in light liquid service.**

(a)(1) Each valve shall be monitored monthly to detect leaks by the methods specified in § 60.485a(b) and shall comply with paragraphs (b) through (e) of this section, except as provided in paragraphs (f), (g), and (h) of this section, § 60.482–1a(c) and (f), and §§ 60.483–1a and 60.483–2a.

(2) A valve that begins operation in gas/vapor service or light liquid service after the initial startup date for the process unit must be monitored according to paragraphs (a)(2)(i) or (ii), except for a valve that replaces a leaking valve and except as provided in paragraphs (f), (g), and (h) of this section, § 60.482–1a(c), and §§ 60.483–1a and 60.483–2a.

(i) Monitor the valve as in paragraph (a)(1) of this section. The valve must be monitored for the first time within 30 days after the end of its startup period to ensure proper installation.

(ii) If the existing valves in the process unit are monitored in accordance with § 60.483–1a or § 60.483–2a, count the new valve as leaking when calculating the percentage of valves leaking as described in § 60.483–2a(b)(5). If less than 2.0 percent of the valves are leaking for that process unit, the valve must be monitored for the first time during the next scheduled monitoring event for existing valves in the process unit or within 90 days, whichever comes first.

(b) If an instrument reading of 500 ppm or greater is measured, a leak is detected.

(c)(1)(i) Any valve for which a leak is not detected for 2 successive months may be monitored the first month of every quarter, beginning with the next quarter, until a leak is detected.

(ii) As an alternative to monitoring all of the valves in the first month of a quarter, an owner or operator may elect to subdivide the process unit into two or three subgroups of valves and monitor each subgroup in a different month during the quarter, provided each subgroup is monitored every 3 months. The owner or operator must keep records of the valves assigned to each subgroup.

(2) If a leak is detected, the valve shall be monitored monthly until a leak is not detected for 2 successive months.

(d)(1) When a leak is detected, it shall be repaired as soon as practicable, but no later than 15 calendar days after the leak is detected, except as provided in § 60.482–9a.

(2) A first attempt at repair shall be made no later than 5 calendar days after each leak is detected.

(e) First attempts at repair include, but are not limited to, the following best practices where practicable:

(1) Tightening of bonnet bolts;

(2) Replacement of bonnet bolts;

(3) Tightening of packing gland nuts;

(4) Injection of lubricant into lubricated packing.

(f) Any valve that is designated, as described in § 60.486a(e)(2), for no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, is exempt from the requirements of paragraph (a) of this section if the valve:

(1) Has no external actuating mechanism in contact with the process fluid,

(2) Is operated with emissions less than 500 ppm above background as determined by the method specified in § 60.485a(c), and

(3) Is tested for compliance with paragraph (f)(2) of this section initially upon designation, annually, and at other times requested by the Administrator.

(g) Any valve that is designated, as described in § 60.486a(f)(1), as an unsafe-to-monitor valve is exempt from the requirements of paragraph (a) of this section if:

(1) The owner or operator of the valve demonstrates that the valve is unsafe to monitor because monitoring personnel would be exposed to an immediate danger as a consequence of complying with paragraph (a) of this section, and

(2) The owner or operator of the valve adheres to a written plan that requires monitoring of the valve as frequently as practicable during safe-to-monitor times.

(h) Any valve that is designated, as described in § 60.486a(f)(2), as a difficult-to-monitor valve is exempt

from the requirements of paragraph (a) of this section if:

(1) The owner or operator of the valve demonstrates that the valve cannot be monitored without elevating the monitoring personnel more than 2 meters above a support surface.

(2) The process unit within which the valve is located either:

(i) Becomes an affected facility through § 60.14 or § 60.15 and was constructed on or before January 5, 1981; or

(ii) Has less than 3.0 percent of its total number of valves designated as difficult-to-monitor by the owner or operator.

(3) The owner or operator of the valve follows a written plan that requires monitoring of the valve at least once per calendar year.

**§ 60.482–8a Standards: Pumps, valves, and connectors in heavy liquid service and pressure relief devices in light liquid or heavy liquid service.**

(a) If evidence of a potential leak is found by visual, audible, olfactory, or any other detection method at pumps, valves, and connectors in heavy liquid service and pressure relief devices in light liquid or heavy liquid service, the owner or operator shall follow either one of the following procedures:

(1) The owner or operator shall monitor the equipment within 5 days by the method specified in § 60.485a(b) and shall comply with the requirements of paragraphs (b) through (d) of this section.

(2) The owner or operator shall eliminate the visual, audible, olfactory, or other indication of a potential leak within 5 calendar days of detection.

(b) If an instrument reading of 10,000 ppm or greater is measured, a leak is detected.

(c)(1) When a leak is detected, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in § 60.482–9a.

(2) The first attempt at repair shall be made no later than 5 calendar days after each leak is detected.

(d) First attempts at repair include, but are not limited to, the best practices described under §§ 60.482–2a(c)(2) and 60.482–7a(e).

**§ 60.482–9a Standards: Delay of repair.**

(a) Delay of repair of equipment for which leaks have been detected will be allowed if repair within 15 days is technically infeasible without a process unit shutdown. Repair of this equipment shall occur before the end of the next process unit shutdown. Monitoring to verify repair must occur within 15 days after startup of the process unit.

(b) Delay of repair of equipment will be allowed for equipment which is isolated from the process and which does not remain in VOC service.

(c) Delay of repair for valves and connectors will be allowed if:

(1) The owner or operator demonstrates that emissions of purged material resulting from immediate repair are greater than the fugitive emissions likely to result from delay of repair, and

(2) When repair procedures are effected, the purged material is collected and destroyed or recovered in a control device complying with § 60.482–10a.

(d) Delay of repair for pumps will be allowed if:

(1) Repair requires the use of a dual mechanical seal system that includes a barrier fluid system, and

(2) Repair is completed as soon as practicable, but not later than 6 months after the leak was detected.

(e) Delay of repair beyond a process unit shutdown will be allowed for a valve, if valve assembly replacement is necessary during the process unit shutdown, valve assembly supplies have been depleted, and valve assembly supplies had been sufficiently stocked before the supplies were depleted. Delay of repair beyond the next process unit shutdown will not be allowed unless the next process unit shutdown occurs sooner than 6 months after the first process unit shutdown.

(f) When delay of repair is allowed for a leaking pump, valve, or connector that remains in service, the pump, valve, or connector may be considered to be repaired and no longer subject to delay of repair requirements if two consecutive monthly monitoring instrument readings are below the leak definition.

**§ 60.482–10a Standards: Closed vent systems and control devices.**

(a) Owners or operators of closed vent systems and control devices used to comply with provisions of this subpart shall comply with the provisions of this section.

(b) Vapor recovery systems (for example, condensers and absorbers) shall be designed and operated to recover the VOC emissions vented to them with an efficiency of 95 percent or greater, or to an exit concentration of 20 parts per million by volume (ppmv), whichever is less stringent.

(c) Enclosed combustion devices shall be designed and operated to reduce the VOC emissions vented to them with an efficiency of 95 percent or greater, or to an exit concentration of 20 ppmv, on a dry basis, corrected to 3 percent oxygen, whichever is less stringent or to provide a minimum residence time of 0.75 seconds at a minimum temperature of 816 °C.

(d) Flares used to comply with this subpart shall comply with the requirements of § 60.18.

(e) Owners or operators of control devices used to comply with the provisions of this subpart shall monitor these control devices to ensure that they are operated and maintained in conformance with their designs.

(f) Except as provided in paragraphs (i) through (k) of this section, each closed vent system shall be inspected according to the procedures and schedule specified in paragraphs (f)(1) and (2) of this section.

(1) If the vapor collection system or closed vent system is constructed of hard-piping, the owner or operator shall comply with the requirements specified in paragraphs (f)(1)(i) and (ii) of this section:

(i) Conduct an initial inspection according to the procedures in § 60.485a(b); and

(ii) Conduct annual visual inspections for visible, audible, or olfactory indications of leaks.

(2) If the vapor collection system or closed vent system is constructed of ductwork, the owner or operator shall:

(i) Conduct an initial inspection according to the procedures in § 60.485a(b); and

(ii) Conduct annual inspections according to the procedures in § 60.485a(b).

(g) Leaks, as indicated by an instrument reading greater than 500 ppmv above background or by visual inspections, shall be repaired as soon as practicable except as provided in paragraph (h) of this section.

(1) A first attempt at repair shall be made no later than 5 calendar days after the leak is detected.

(2) Repair shall be completed no later than 15 calendar days after the leak is detected.

(h) Delay of repair of a closed vent system for which leaks have been detected is allowed if the repair is technically infeasible without a process unit shutdown or if the owner or operator determines that emissions resulting from immediate repair would be greater than the fugitive emissions likely to result from delay of repair. Repair of such equipment shall be complete by the end of the next process unit shutdown.

(i) If a vapor collection system or closed vent system is operated under a vacuum, it is exempt from the

inspection requirements of paragraphs (f)(1)(i) and (f)(2) of this section.

(j) Any parts of the closed vent system that are designated, as described in paragraph (l)(1) of this section, as unsafe to inspect are exempt from the inspection requirements of paragraphs (f)(1)(i) and (f)(2) of this section if they comply with the requirements specified in paragraphs (j)(1) and (2) of this section:

(1) The owner or operator determines 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 (f)(1)(i) or (f)(2) of this section; and

(2) The owner or operator has a written plan that requires inspection of the equipment as frequently as practicable during safe-to-inspect times.

(k) Any parts of the closed vent system that are designated, as described in paragraph (l)(2) of this section, as difficult to inspect are exempt from the inspection requirements of paragraphs (f)(1)(i) and (f)(2) of this section if they comply with the requirements specified in paragraphs (k)(1) through (3) of this section:

(1) The owner or operator determines that the equipment cannot be inspected without elevating the inspecting personnel more than 2 meters above a support surface; and

(2) The process unit within which the closed vent system is located becomes an affected facility through §§ 60.14 or 60.15, or the owner or operator designates less than 3.0 percent of the total number of closed vent system equipment as difficult to inspect; and

(3) The owner or operator has a written plan that requires inspection of the equipment at least once every 5 years. A closed vent system is exempt from inspection if it is operated under a vacuum.

(l) The owner or operator shall record the information specified in paragraphs (l)(1) through (5) of this section.

(1) Identification of all parts of the closed vent system that are designated as unsafe to inspect, an explanation of why the equipment is unsafe to inspect, and the plan for inspecting the equipment.

(2) Identification of all parts of the closed vent system that are designated as difficult to inspect, an explanation of why the equipment is difficult to inspect, and the plan for inspecting the equipment.

(3) For each inspection during which a leak is detected, a record of the information specified in § 60.486a(c).

(4) For each inspection conducted in accordance with § 60.485a(b) during which no leaks are detected, a record that the inspection was performed, the date of the inspection, and a statement that no leaks were detected.

(5) For each visual inspection conducted in accordance with paragraph (f)(1)(ii) of this section during which no leaks are detected, a record that the inspection was performed, the date of the inspection, and a statement that no leaks were detected.

(m) Closed vent systems and control devices used to comply with provisions of this subpart shall be operated at all times when emissions may be vented to them.

**§ 60.482–11a Standards: Connectors in gas/vapor service and in light liquid service.**

(a) The owner or operator shall initially monitor all connectors in the process unit for leaks by the later of either 12 months after the compliance date or 12 months after initial startup. If all connectors in the process unit have been monitored for leaks prior to the compliance date, no initial monitoring is required provided either no process changes have been made since the monitoring or the owner or operator can determine that the results of the monitoring, with or without adjustments, reliably demonstrate compliance despite process changes. If required to monitor because of a process change, the owner or operator is required to monitor only those connectors involved in the process change.

(b) Except as allowed in § 60.482–1a(c), § 60.482–10a, or as specified in paragraph (e) of this section, the owner or operator shall monitor all connectors in gas and vapor and light liquid service as specified in paragraphs (a) and (b)(3) of this section.

(1) The connectors shall be monitored to detect leaks by the method specified in § 60.485a(b) and, as applicable, § 60.485a(c).

(2) If an instrument reading greater than or equal to 500 ppm is measured, a leak is detected.

(3) The owner or operator shall perform monitoring, subsequent to the initial monitoring required in paragraph (a) of this section, as specified in paragraphs (b)(3)(i) through (iii) of this section, and shall comply with the requirements of paragraphs (b)(3)(iv) and (v) of this section. The required period in which monitoring must be conducted shall be determined from paragraphs (b)(3)(i) through (iii) of this section using the monitoring results from the preceding monitoring period. The percent leaking connectors shall be calculated as specified in paragraph (c) of this section.

(i) If the percent leaking connectors in the process unit was greater than or equal to 0.5 percent, then monitor within 12 months (1 year).

(ii) If the percent leaking connectors in the process unit was greater than or equal to 0.25 percent but less than 0.5 percent, then monitor within 4 years. An owner or operator may comply with the requirements of this paragraph by monitoring at least 40 percent of the connectors within 2 years of the start of the monitoring period, provided all connectors have been monitored by the end of the 4-year monitoring period.

(iii) If the percent leaking connectors in the process unit was less than 0.25 percent, then monitor as provided in paragraph (b)(3)(iii)(A) of this section and either paragraph (b)(3)(iii)(B) or (b)(3)(iii)(C) of this section, as appropriate.

(A) An owner or operator shall monitor at least 50 percent of the connectors within 4 years of the start of the monitoring period.

(B) If the percent of leaking connectors calculated from the monitoring results in paragraph (b)(3)(iii)(A) of this section is greater than or equal to 0.35 percent of the monitored connectors, the owner or operator shall monitor as soon as practical, but within the next 6 months, all connectors that have not yet been monitored during the monitoring period. At the conclusion of monitoring, a new monitoring period shall be started pursuant to paragraph (b)(3) of this section, based on the percent of leaking connectors within the total monitored connectors.

(C) If the percent of leaking connectors calculated from the monitoring results in paragraph (b)(3)(iii)(A) of this section is less than 0.35 percent of the monitored connectors, the owner or operator shall monitor all connectors that have not yet been monitored within 8 years of the start of the monitoring period.

(iv) If, during the monitoring conducted pursuant to paragraphs (b)(3)(i) through (iii) of this section, a connector is found to be leaking, it shall be re-monitored once within 90 days after repair to confirm that it is not leaking.

(v) The owner or operator shall keep a record of the start date and end date of each monitoring period under this section for each process unit.

(c) For use in determining the monitoring frequency, as specified in paragraphs (a) and (b)(3) of this section, the percent leaking connectors as used in paragraphs (a) and (b)(3) of this section shall be calculated by using the following equation:

$\%C_L = C_L / C_t * 100$

Where:

$\%C_L$ = Percent of leaking connectors as determined through periodic monitoring required in paragraphs (a) and (b)(3)(i) through (iii) of this section.

$C_L$ = Number of connectors measured at 500 ppm or greater, by the method specified in § 60.485a(b).

$C_t$ = Total number of monitored connectors in the process unit or affected facility.

(d) When a leak is detected pursuant to paragraphs (a) and (b) of this section, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in § 60.482–9a. A first attempt at repair as defined in this subpart shall be made no later than 5 calendar days after the leak is detected.

(e) Any connector that is designated, as described in § 60.486a(f)(1), as an unsafe-to-monitor connector is exempt from the requirements of paragraphs (a) and (b) of this section if:

(1) The owner or operator of the connector demonstrates that the connector is unsafe-to-monitor because monitoring personnel would be exposed to an immediate danger as a consequence of complying with paragraphs (a) and (b) of this section; and

(2) The owner or operator of the connector has a written plan that requires monitoring of the connector as frequently as practicable during safe-to-monitor times but not more frequently than the periodic monitoring schedule otherwise applicable, and repair of the equipment according to the procedures in paragraph (d) of this section if a leak is detected.

(f) *Inaccessible, ceramic, or ceramic-lined connectors.* (1) Any connector that is inaccessible or that is ceramic or ceramic-lined (e.g., porcelain, glass, or glass-lined), is exempt from the monitoring requirements of paragraphs (a) and (b) of this section, from the leak repair requirements of paragraph (d) of this section, and from the recordkeeping and reporting requirements of §§ 63.1038 and 63.1039. An inaccessible connector is one that meets any of the provisions specified in paragraphs (f)(1)(i) through (vi) of this section, as applicable:

(i) Buried;

(ii) Insulated in a manner that prevents access to the connector by a monitor probe;

(iii) Obstructed by equipment or piping that prevents access to the connector by a monitor probe;

(iv) Unable to be reached from a wheeled scissor-lift or hydraulic-type scaffold that would allow access to connectors up to 7.6 meters (25 feet) above the ground;

(v) Inaccessible because it would require elevating the monitoring personnel more than 2 meters (7 feet) above a permanent support surface or would require the erection of scaffold; or

(vi) Not able to be accessed at any time in a safe manner to perform monitoring. Unsafe access includes, but is not limited to, the use of a wheeled scissor-lift on unstable or uneven terrain, the use of a motorized man-lift basket in areas where an ignition potential exists, or access would require near proximity to hazards such as electrical lines, or would risk damage to equipment.

(2) If any inaccessible, ceramic, or ceramic-lined connector is observed by visual, audible, olfactory, or other means to be leaking, the visual, audible, olfactory, or other indications of a leak to the atmosphere shall be eliminated as soon as practical.

(g) Except for instrumentation systems and inaccessible, ceramic, or ceramic-lined connectors meeting the provisions of paragraph (f) of this section, identify the connectors subject to the requirements of this subpart. Connectors need not be individually identified if all connectors in a designated area or length of pipe subject to the provisions of this subpart are identified as a group, and the number of connectors subject is indicated.

**§ 60.483–1a Alternative standards for valves—allowable percentage of valves leaking.**

(a) An owner or operator may elect to comply with an allowable percentage of valves leaking of equal to or less than 2.0 percent.

(b) The following requirements shall be met if an owner or operator wishes to comply with an allowable percentage of valves leaking:

(1) An owner or operator must notify the Administrator that the owner or operator has elected to comply with the allowable percentage of valves leaking before implementing this alternative standard, as specified in § 60.487a(d).

(2) A performance test as specified in paragraph (c) of this section shall be conducted initially upon designation, annually, and at other times requested by the Administrator.

(3) If a valve leak is detected, it shall be repaired in accordance with § 60.482–7a(d) and (e).

(c) Performance tests shall be conducted in the following manner:

(1) All valves in gas/vapor and light liquid service within the affected facility shall be monitored within 1 week by the methods specified in § 60.485a(b).

(2) If an instrument reading of 500 ppm or greater is measured, a leak is detected.

(3) The leak percentage shall be determined by dividing the number of valves for which leaks are detected by the number of valves in gas/vapor and light liquid service within the affected facility.

(d) Owners and operators who elect to comply with this alternative standard shall not have an affected facility with a leak percentage greater than 2.0 percent, determined as described in § 60.485a(h).

**§ 60.483–2a Alternative standards for valves—skip period leak detection and repair.**

(a)(1) An owner or operator may elect to comply with one of the alternative work practices specified in paragraphs (b)(2) and (3) of this section.

(2) An owner or operator must notify the Administrator before implementing one of the alternative work practices, as specified in § 60.487(d)a.

(b)(1) An owner or operator shall comply initially with the requirements for valves in gas/vapor service and valves in light liquid service, as described in § 60.482–7a.

(2) After 2 consecutive quarterly leak detection periods with the percent of valves leaking equal to or less than 2.0, an owner or operator may begin to skip 1 of the quarterly leak detection periods for the valves in gas/vapor and light liquid service.

(3) After 5 consecutive quarterly leak detection periods with the percent of valves leaking equal to or less than 2.0, an owner or operator may begin to skip 3 of the quarterly leak detection periods for the valves in gas/vapor and light liquid service.

(4) If the percent of valves leaking is greater than 2.0, the owner or operator shall comply with the requirements as described in § 60.482–7a but can again elect to use this section.

(5) The percent of valves leaking shall be determined as described in § 60.485a(h).

(6) An owner or operator must keep a record of the percent of valves found leaking during each leak detection period.

(7) A valve that begins operation in gas/vapor service or light liquid service after the initial startup date for a process unit following one of the alternative standards in this section must be monitored in accordance with § 60.482–7a(a)(2)(i) or (ii) before the provisions of this section can be applied to that valve.

**§ 60.484a Equivalence of means of emission limitation.**

(a) Each owner or operator subject to the provisions of this subpart may apply to the Administrator for determination of equivalence for any means of emission limitation that achieves a reduction in emissions of VOC at least equivalent to the reduction in emissions of VOC achieved by the controls required in this subpart.

(b) Determination of equivalence to the equipment, design, and operational requirements of this subpart will be evaluated by the following guidelines:

(1) Each owner or operator applying for an equivalence determination shall be responsible for collecting and verifying test data to demonstrate equivalence of means of emission limitation.

(2) The Administrator will compare test data for demonstrating equivalence of the means of emission limitation to test data for the equipment, design, and operational requirements.

(3) The Administrator may condition the approval of equivalence on requirements that may be necessary to assure operation and maintenance to achieve the same emission reduction as the equipment, design, and operational requirements.

(c) Determination of equivalence to the required work practices in this subpart will be evaluated by the following guidelines:

(1) Each owner or operator applying for a determination of equivalence shall be responsible for collecting and verifying test data to demonstrate equivalence of an equivalent means of emission limitation.

(2) For each affected facility for which a determination of equivalence is requested, the emission reduction achieved by the required work practice shall be demonstrated.

(3) For each affected facility, for which a determination of equivalence is requested, the emission reduction achieved by the equivalent means of emission limitation shall be demonstrated.

(4) Each owner or operator applying for a determination of equivalence 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.

(5) The Administrator will compare the demonstrated emission reduction for the equivalent means of emission limitation to the demonstrated emission reduction for the required work practices and will consider the commitment in paragraph (c)(4) of this section.

(6) The Administrator may condition the approval of equivalence on requirements that may be necessary to assure operation and maintenance to achieve the same emission reduction as the required work practice.

(d) An owner or operator may offer a unique approach to demonstrate the equivalence of any equivalent means of emission limitation.

(e)(1) 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.

(2) 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**.

(3) 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.

(f)(1) Manufacturers of equipment used to control equipment leaks of VOC may apply to the Administrator for determination of equivalence for any equivalent means of emission limitation that achieves a reduction in emissions of VOC achieved by the equipment, design, and operational requirements of this subpart.

(2) The Administrator will make an equivalence determination according to the provisions of paragraphs (b), (c), (d), and (e) of this section.

**§ 60.485a Test methods and procedures.**

(a) In conducting the performance tests required in § 60.8, the owner or operator shall use as reference methods and procedures 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) The owner or operator shall determine compliance with the standards in §§ 60.482–1a through 60.482–11a, 60.483a, and 60.484a as follows:

(1) Method 21 shall be used to determine the presence of leaking sources. The instrument shall be calibrated before use each day of its use by the procedures specified in Method 21 of appendix A–7 of this part. The following calibration gases shall be used:

(i) Zero air (less than 10 ppm of hydrocarbon in air); and

(ii) A mixture of methane or n-hexane and air at a concentration no more than 2,000 ppm greater than the leak definition concentration of the equipment monitored. If the monitoring instrument's design allows for multiple calibration scales, then the lower scale shall be calibrated with a calibration gas that is no higher than 2,000 ppm above the concentration specified as a leak, and the highest scale shall be calibrated with a calibration gas that is approximately equal to 10,000 ppm. If only one scale on an instrument will be used during monitoring, the owner or operator need not calibrate the scales that will not be used during that day's monitoring.

(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)(7). Calculate the average algebraic difference between the three meter readings and the most recent calibration value. Divide this algebraic difference by the initial calibration value 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.

(c) The owner or operator shall determine compliance with the no-detectable-emission standards in §§ 60.482–2a(e), 60.482–3a(i), 60.482–4a, 60.482–7a(f), and 60.482–10a(e) as follows:

(1) The requirements of paragraph (b) shall apply.

(2) Method 21 of appendix A–7 of this part shall be used to determine the background level. All potential leak interfaces shall be traversed as close to the interface as possible. The arithmetic difference between the maximum

concentration indicated by the instrument and the background level is compared with 500 ppm for determining compliance.

(d) The owner or operator shall test each piece of equipment unless he demonstrates that a process unit is not in VOC service, i.e., that the VOC content would never be reasonably expected to exceed 10 percent by weight. For purposes of this demonstration, the following methods and procedures shall be used:

(1) Procedures that conform to the general methods in ASTM E260–73, 91, or 96, E168–67, 77, or 92, E169–63, 77, or 93 (incorporated by reference—see § 60.17) shall be used to determine the percent VOC content in the process fluid that is contained in or contacts a piece of equipment.

(2) Organic compounds that are considered by the Administrator to have negligible photochemical reactivity may be excluded from the total quantity of organic compounds in determining the VOC content of the process fluid.

(3) Engineering judgment may be used to estimate the VOC content, if a piece of equipment had not been shown previously to be in service. If the Administrator disagrees with the judgment, paragraphs (d)(1) and (2) of this section shall be used to resolve the disagreement.

(e) The owner or operator shall demonstrate that a piece of equipment is in light liquid service by showing that all the following conditions apply:

(1) The vapor pressure of one or more of the organic components is greater than 0.3 kPa at 20 °C (1.2 in. $H_2O$ at 68 °F). Standard reference texts or ASTM D2879–83, 96, or 97 (incorporated by reference—see § 60.17) shall be used to determine the vapor pressures.

(2) The total concentration of the pure organic components having a vapor pressure greater than 0.3 kPa at 20 °C (1.2 in. $H_2O$ at 68 °F) is equal to or greater than 20 percent by weight.

(3) The fluid is a liquid at operating conditions.

(f) Samples used in conjunction with paragraphs (d), (e), and (g) of this section shall be representative of the process fluid that is contained in or contacts the equipment or the gas being combusted in the flare.

(g) The owner or operator shall determine compliance with the standards of flares as follows:

(1) Method 22 of appendix A–7 of this part shall be used to determine visible emissions.

(2) A thermocouple or any other equivalent device shall be used to monitor the presence of a pilot flame in the flare.

(3) The maximum permitted velocity for air assisted flares shall be computed using the following equation:

$$V_{max} = K_1 + K_2 H_T$$

Where:

$V_{max}$ = Maximum permitted velocity, m/sec (ft/sec).

$H_T$ = Net heating value of the gas being combusted, MJ/scm (Btu/scf).

$K_1$ = 8.706 m/sec (metric units) = 28.56 ft/sec (English units).

$K_2$ = 0.7084 $m^4$/(MJ-sec) (metric units) = 0.087 $ft^4$/(Btu-sec) (English units).

(4) The net heating value (HT) of the gas being combusted in a flare shall be computed using the following equation:

$$H_T = K \sum_{i=1}^{n} C_i H_i$$

Where:

K = Conversion constant, $1.740 \times 10^{-7}$ (g-mole)(MJ)/(ppm-scm-kcal) (metric units) = $4.674 \times 10^{-6}$ [(g-mole)(Btu)/(ppm-scf-kcal)] (English units).

$C_i$ = Concentration of sample component "i," ppm

$H_i$ = net heat of combustion of sample component "i" at 25 °C and 760 mm Hg (77 °F and 14.7 psi), kcal/g-mole.

(5) Method 18 of appendix A–6 of this part or ASTM D6420–99 (2004) (where the target compound(s) are those listed in Section 1.1 of ASTM D6420–99, and the target concentration is between 150 parts per billion by volume and 100 ppmv) and ASTM D2504–67, 77, or 88 (Reapproved 1993) (incorporated by reference-see § 60.17) shall be used to determine the concentration of sample component "i."

(6) ASTM D2382–76 or 88 or D4809–95 (incorporated by reference-see § 60.17) shall be used to determine the net heat of combustion of component "i" if published values are not available or cannot be calculated.

(7) Method 2, 2A, 2C, or 2D of appendix A–7 of this part, as appropriate, shall be used to determine the actual exit velocity of a flare. If needed, the unobstructed (free) cross-sectional area of the flare tip shall be used.

(h) The owner or operator shall determine compliance with § 60.483–1a or § 60.483–2a as follows:

(1) The percent of valves leaking shall be determined using the following equation:

$$\%V_L = (V_L / V_T) * 100$$

Where:

$\%V_L$ = Percent leaking valves.

$V_L$ = Number of valves found leaking.

$V_T$ = The sum of the total number of valves monitored.

(2) The total number of valves monitored shall include difficult-to-monitor and unsafe-to-monitor valves only during the monitoring period in which those valves are monitored.

(3) The number of valves leaking shall include valves for which repair has been delayed.

(4) Any new valve that is not monitored within 30 days of being placed in service shall be included in the number of valves leaking and the total number of valves monitored for the monitoring period in which the valve is placed in service.

(5) If the process unit has been subdivided in accordance with § 60.482–7a(c)(1)(ii), the sum of valves found leaking during a monitoring period includes all subgroups.

(6) The total number of valves monitored does not include a valve monitored to verify repair.

**§ 60.486a Recordkeeping requirements.**

(a)(1) Each owner or operator subject to the provisions of this subpart shall comply with the recordkeeping requirements of this section.

(2) An owner or operator of more than one affected facility subject to the provisions of this subpart may comply with the recordkeeping requirements for these facilities in one recordkeeping system if the system identifies each record by each facility.

(3) The owner or operator shall record the information specified in paragraphs (a)(3)(i) through (v) of this section for each monitoring event required by §§ 60.482–2a, 60.482–3a, 60.482–7a, 60.482–8a, 60.482–11a, and 60.483–2a.

(i) Monitoring instrument identification.

(ii) Operator identification.

(iii) Equipment identification.

(iv) Date of monitoring.

(v) Instrument reading.

(b) When each leak is detected as specified in §§ 60.482–2a, 60.482–3a, 60.482–7a, 60.482–8a, 60.482–11a, and 60.483–2a, the following requirements apply:

(1) A weatherproof and readily visible identification, marked with the equipment identification number, shall be attached to the leaking equipment.

(2) The identification on a valve may be removed after it has been monitored for 2 successive months as specified in § 60.482–7a(c) and no leak has been detected during those 2 months.

(3) The identification on a connector may be removed after it has been monitored as specified in § 60.482–11a(b)(3)(iv) and no leak has been detected during that monitoring.

(4) The identification on equipment, except on a valve or connector, may be removed after it has been repaired.

(c) When each leak is detected as specified in §§ 60.482–2a, 60.482–3a, 60.482–7a, 60.482–8a, 60.482–11a, and 60.483–2a, the following information shall be recorded in a log and shall be kept for 2 years in a readily accessible location:

(1) The instrument and operator identification numbers and the equipment identification number, except when indications of liquids dripping from a pump are designated as a leak.

(2) The date the leak was detected and the dates of each attempt to repair the leak.

(3) Repair methods applied in each attempt to repair the leak.

(4) Maximum instrument reading measured by Method 21 of appendix A–7 of this part at the time the leak is successfully repaired or determined to be nonrepairable, except when a pump is repaired by eliminating indications of liquids dripping.

(5) "Repair delayed" and the reason for the delay if a leak is not repaired within 15 calendar days after discovery of the leak.

(6) The signature of the owner or operator (or designate) whose decision it was that repair could not be effected without a process shutdown.

(7) The expected date of successful repair of the leak if a leak is not repaired within 15 days.

(8) Dates of process unit shutdowns that occur while the equipment is unrepaired.

(9) The date of successful repair of the leak.

(d) The following information pertaining to the design requirements for closed vent systems and control devices described in § 60.482–10a shall be recorded and kept in a readily accessible location:

(1) Detailed schematics, design specifications, and piping and instrumentation diagrams.

(2) The dates and descriptions of any changes in the design specifications.

(3) A description of the parameter or parameters monitored, as required in § 60.482–10a(e), to ensure that control devices are operated and maintained in conformance with their design and an explanation of why that parameter (or parameters) was selected for the monitoring.

(4) Periods when the closed vent systems and control devices required in §§ 60.482–2a, 60.482–3a, 60.482–4a, and 60.482–5a are not operated as designed, including periods when a flare pilot light does not have a flame.

(5) Dates of startups and shutdowns of the closed vent systems and control devices required in §§ 60.482–2a, 60.482–3a, 60.482–4a, and 60.482–5a.

(e) The following information pertaining to all equipment subject to the requirements in §§ 60.482–1a to 60.482–11a shall be recorded in a log that is kept in a readily accessible location:

(1) A list of identification numbers for equipment subject to the requirements of this subpart.

(2)(i) A list of identification numbers for equipment that are designated for no detectable emissions under the provisions of §§ 60.482–2a(e), 60.482–3a(i), and 60.482–7a(f).

(ii) The designation of equipment as subject to the requirements of § 60.482–2a(e), § 60.482–3a(i), or § 60.482–7a(f) shall be signed by the owner or operator. Alternatively, the owner or operator may establish a mechanism with their permitting authority that satisfies this requirement.

(3) A list of equipment identification numbers for pressure relief devices required to comply with § 60.482–4a.

(4)(i) The dates of each compliance test as required in §§ 60.482–2a(e), 60.482–3a(i), 60.482–4a, and 60.482–7a(f).

(ii) The background level measured during each compliance test.

(iii) The maximum instrument reading measured at the equipment during each compliance test.

(5) A list of identification numbers for equipment in vacuum service.

(6) A list of identification numbers for equipment that the owner or operator designates as operating in VOC service less than 300 hr/yr in accordance with § 60.482–1a(e), a description of the conditions under which the equipment is in VOC service, and rationale supporting the designation that it is in VOC service less than 300 hr/yr.

(7) The date and results of the weekly visual inspection for indications of liquids dripping from pumps in light liquid service.

(8) Records of the information specified in paragraphs (e)(8)(i) through (vi) of this section for monitoring instrument calibrations conducted according to sections 8.1.2 and 10 of Method 21 of appendix A–7 of this part and § 60.485a(b).

(i) Date of calibration and initials of operator performing the calibration.

(ii) Calibration gas cylinder identification, certification date, and certified concentration.

(iii) Instrument scale(s) used.

(iv) A description of any corrective action taken if the meter readout could not be adjusted to correspond to the calibration gas value in accordance with section 10.1 of Method 21 of appendix A–7 of this part.

(v) Results of each calibration drift assessment required by § 60.485a(b)(2) (i.e., instrument reading for calibration at end of monitoring day and the calculated percent difference from the initial calibration value).

(vi) If an owner or operator makes their own calibration gas, a description of the procedure used.

(9) The connector monitoring schedule for each process unit as specified in § 60.482–11a(b)(3)(v).

(10) Records of each release from a pressure relief device subject to § 60.482–4a.

(f) The following information pertaining to all valves subject to the requirements of § 60.482–7a(g) and (h), all pumps subject to the requirements of § 60.482–2a(g), and all connectors subject to the requirements of § 60.482–11a(e) shall be recorded in a log that is kept in a readily accessible location:

(1) A list of identification numbers for valves, pumps, and connectors that are designated as unsafe-to-monitor, an explanation for each valve, pump, or connector stating why the valve, pump, or connector is unsafe-to-monitor, and the plan for monitoring each valve, pump, or connector.

(2) A list of identification numbers for valves that are designated as difficult-to-monitor, an explanation for each valve stating why the valve is difficult-to-monitor, and the schedule for monitoring each valve.

(g) The following information shall be recorded for valves complying with § 60.483–2a:

(1) A schedule of monitoring.

(2) The percent of valves found leaking during each monitoring period.

(h) The following information shall be recorded in a log that is kept in a readily accessible location:

(1) Design criterion required in §§ 60.482–2a(d)(5) and 60.482–3a(e)(2) and explanation of the design criterion; and

(2) Any changes to this criterion and the reasons for the changes.

(i) The following information shall be recorded in a log that is kept in a readily accessible location for use in determining exemptions as provided in § 60.480a(d):

(1) An analysis demonstrating the design capacity of the affected facility,

(2) A statement listing the feed or raw materials and products from the affected facilities and an analysis demonstrating whether these chemicals are heavy liquids or beverage alcohol, and

(3) An analysis demonstrating that equipment is not in VOC service.

(j) Information and data used to demonstrate that a piece of equipment is not in VOC service shall be recorded

in a log that is kept in a readily accessible location.

(k) The provisions of § 60.7(b) and (d) do not apply to affected facilities subject to this subpart.

**§ 60.487a Reporting requirements.**

(a) Each owner or operator subject to the provisions of this subpart shall submit semiannual reports to the Administrator beginning 6 months after the initial startup date.

(b) The initial semiannual report to the Administrator shall include the following information:

(1) Process unit identification.

(2) Number of valves subject to the requirements of § 60.482–7a, excluding those valves designated for no detectable emissions under the provisions of § 60.482–7a(f).

(3) Number of pumps subject to the requirements of § 60.482–2a, excluding those pumps designated for no detectable emissions under the provisions of § 60.482–2a(e) and those pumps complying with § 60.482–2a(f).

(4) Number of compressors subject to the requirements of § 60.482–3a, excluding those compressors designated for no detectable emissions under the provisions of § 60.482–3a(i) and those compressors complying with § 60.482–3a(h).

(5) Number of connectors subject to the requirements of § 60.482–11a.

(c) All semiannual reports to the Administrator shall include the following information, summarized from the information in § 60.486a:

(1) Process unit identification.

(2) For each month during the semiannual reporting period,

(i) Number of valves for which leaks were detected as described in § 60.482–7a(b) or § 60.483–2a,

(ii) Number of valves for which leaks were not repaired as required in § 60.482–7a(d)(1),

(iii) Number of pumps for which leaks were detected as described in § 60.482–2a(b), (d)(4)(ii)(A) or (B), or (d)(5)(iii),

(iv) Number of pumps for which leaks were not repaired as required in § 60.482–2a(c)(1) and (d)(6),

(v) Number of compressors for which leaks were detected as described in § 60.482–3a(f),

(vi) Number of compressors for which leaks were not repaired as required in § 60.482–3a(g)(1),

(vii) Number of connectors for which leaks were detected as described in § 60.482–11a(b)

(viii) Number of connectors for which leaks were not repaired as required in § 60.482–11a(d), and

(xi) The facts that explain each delay of repair and, where appropriate, why a process unit shutdown was technically infeasible.

(3) Dates of process unit shutdowns which occurred within the semiannual reporting period.

(4) Revisions to items reported according to paragraph (b) of this section if changes have occurred since the initial report or subsequent revisions to the initial report.

(d) An owner or operator electing to comply with the provisions of §§ 60.483–1a or 60.483–2a shall notify the Administrator of the alternative standard selected 90 days before implementing either of the provisions.

(e) An owner or operator shall report the results of all performance tests in accordance with § 60.8 of the General Provisions. The provisions of § 60.8(d) do not apply to affected facilities subject to the provisions of this subpart except that an owner or operator must notify the Administrator of the schedule for the initial performance tests at least 30 days before the initial performance tests.

(f) The requirements of paragraphs (a) through (c) of this section remain in force until and unless EPA, in delegating enforcement authority to a state under section 111(c) of the CAA, 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 the obligation to comply with the requirements of paragraphs (a) through (c) of this section, provided that they comply with the requirements established by the state.

**§ 60.488a Reconstruction.**

For the purposes of this subpart:

(a) The cost of the following frequently replaced components of the facility shall not be considered in calculating either the "fixed capital cost of the new components" or the "fixed capital costs that would be required to construct a comparable new facility" under § 60.15: Pump seals, nuts and bolts, rupture disks, and packings.

(b) Under § 60.15, the "fixed capital cost of new components" includes the fixed capital cost of all depreciable components (except components specified in § 60.488a(a)) which are or will be replaced pursuant to all continuous programs of component replacement which are commenced within any 2-year period following the applicability date for the appropriate subpart. (See the "Applicability and designation of affected facility" section of the appropriate subpart.) For purposes of this paragraph, "commenced" means that an owner or operator has undertaken a continuous program of component replacement or that an owner or operator has entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of component replacement.

**§ 60.489a List of chemicals produced by affected facilities.**

Process units that produce, as intermediates or final products, chemicals listed in § 60.489 are covered under this subpart. The applicability date for process units producing one or more of these chemicals is November 8, 2006.

## Subpart GGG—Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for which Construction, Reconstruction, or Modification Commenced After January 4, 1983, and on or Before November 7, 2006

■ 21. The heading for Subpart GGG is revised as set out above.

■ 22. Section 60.590 is amended by revising paragraphs (b) and (d) to read as follows:

**§ 60.590 Applicability and designation of affected facility.**

* * * * *

(b) Any affected facility under paragraph (a) of this section that commences construction, reconstruction, or modification after January 4, 1983, and on or before November 7, 2006, is subject to the requirements of this subpart.

* * * * *

(d) Facilities subject to subpart VV, subpart VVa, or subpart KKK of this part are excluded from this subpart.

* * * * *

■ 23. Section 60.591 is amended by adding a definition of "Asphalt" in alphabetical order and revising the definition of "Process unit" to read as follows:

**§ 60.591 Definitions.**

* * * * *

*Asphalt* (also known as Bitumen) is a black or dark brown solid or semi-solid thermo-plastic material possessing waterproofing and adhesive properties. It is a complex combination of higher molecular weight organic compounds containing a relatively high proportion of hydrocarbons having carbon numbers greater than C25 with a high carbon to hydrogen ratio. It is essentially non-volatile at ambient temperatures with closed cup flash point of 445 °F (230 °C) or greater.

* * * * *

*Process unit* means the components assembled and connected by pipes or ducts to process raw materials and to produce intermediate or final products from petroleum, unfinished petroleum derivatives, or other intermediates. A process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the product. For the purpose of this subpart, process unit includes any feed, intermediate and final product storage vessels (except as specified in § 60.482–1(g)), product transfer racks, and connected ducts and piping. A process unit includes all equipment as defined in this subpart.

■ 24. Section 60.592 is amended by revising paragraph (b) to read as follows:

**§ 60.592 Standards.**

* * * * *

(b) For a given process unit, an owner or operator may elect to comply with the requirements of paragraphs (b)(1), (2), or (3) of this section as an alternative to the requirements in § 60.482–7.

(1) Comply with § 60.483–1.

(2) Comply with § 60.483–2.

(3) Comply with the Phase III provisions in 40 CFR 63.168, except an owner or operator may elect to follow the provisions in § 60.482–7(f) instead of 40 CFR 63.168 for any valve that is designated as being leakless.

* * * * *

■ 25. Section 60.593 is amended by:

■ a. Revising the first sentence of paragraph (b)(2);

■ b. Revising paragraphs (c) and (d); and

■ c. Adding paragraph (f) to read as follows:

**§ 60.593 Exceptions.**

* * * * *

(b) * * *

(2) Each compressor is presumed not to be in hydrogen service unless an owner or operator demonstrates that the piece of equipment is in hydrogen service. * * *

* * * * *

(c) Any existing reciprocating compressor that becomes an affected facility under provisions of § 60.14 or § 60.15 is exempt from § 60.482–3(a), (b), (c), (d), (e), and (h) provided the owner or operator demonstrates that recasting the distance piece or replacing the compressor are the only options available to bring the compressor into compliance with the provisions of § 60.482–3(a), (b), (c), (d), (e), and (h).

(d) An owner or operator may use the following provision in addition to § 60.485(e): Equipment is in light liquid service if the percent evaporated is greater than 10 percent at 150 °C as determined by ASTM Method D86–78, 82, 90, 95, or 96 (incorporated by reference as specified in § 60.17).

* * * * *

(f) Open-ended valves or lines containing asphalt as defined in § 60.591 are exempt from the requirements of § 60.482–6(a) through (c).

■ 26. Part 60 is amended by adding subpart GGGa to read as follows:

## Subpart GGGa—Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for which Construction, Reconstruction, or Modification Commenced After November 7, 2006

Sec.



**§ 60.590a Applicability and designation of affected facility.**

(a)(1) The provisions of this subpart apply to affected facilities in petroleum refineries.

(2) A compressor is an affected facility.

(3) The group of all the equipment (defined in § 60.591a) within a process unit is an affected facility.

(b) Any affected facility under paragraph (a) of this section that commences construction, reconstruction, or modification after November 7, 2006, is subject to the requirements of this subpart.

(c) Addition or replacement of equipment (defined in § 60.591a) for the purpose of process improvement which is accomplished without a capital expenditure shall not by itself be considered a modification under this subpart.

(d) Facilities subject to subpart VV, subpart VVa, subpart GGG, or subpart KKK of this part are excluded from this subpart.

**§ 60.591a Definitions.**

As used in this subpart, all terms not defined herein shall have the meaning given them in the Clean Air Act, in subpart A of part 60, or in subpart VVa of this part, and the following terms shall have the specific meanings given them.

*Alaskan North Slope* means the approximately 69,000 square mile area extending from the Brooks Range to the Arctic Ocean.

*Asphalt* (also known as Bitumen) is a black or dark brown solid or semi-solid thermo-plastic material possessing waterproofing and adhesive properties. It is a complex combination of higher molecular weight organic compounds containing a relatively high proportion of hydrocarbons having carbon numbers greater than C25 with a high carbon to hydrogen ratio. It is essentially non-volatile at ambient temperatures with closed cup flash point of 445 ° F (230 ° C) or greater.

*Equipment* means each valve, pump, pressure relief device, sampling connection system, open-ended valve or line, and flange or other connector in VOC service. For the purposes of recordkeeping and reporting only, compressors are considered equipment.

*In hydrogen service* means that a compressor contains a process fluid that meets the conditions specified in § 60.593a(b).

*In light liquid service* means that the piece of equipment contains a liquid that meets the conditions specified in § 60.593a(c).

*Petroleum* means the crude oil removed from the earth and the oils derived from tar sands, shale, and coal.

*Petroleum refinery* means any facility engaged in producing gasoline, kerosene, distillate fuel oils, residual fuel oils, lubricants, or other products through the distillation of petroleum, or through the redistillation, cracking, or reforming of unfinished petroleum derivatives.

*Process unit* means the components assembled and connected by pipes or ducts to process raw materials and to produce intermediate or final products from petroleum, unfinished petroleum derivatives, or other intermediates. A process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the product. For the purpose of this subpart, process unit includes any feed, intermediate and final product storage vessels (except as specified in § 60.482–1a(g)), product transfer racks, and connected ducts and piping. A process unit includes all equipment as defined in this subpart.

**§ 60.592a Standards.**

(a) Each owner or operator subject to the provisions of this subpart shall comply with the requirements of §§ 60.482–1a to 60.482–10a as soon as practicable, but no later than 180 days after initial startup.

(b) For a given process unit, an owner or operator may elect to comply with the requirements of paragraphs (b)(1), (2), or (3) of this section as an alternative to the requirements in § 60.482–7a.

(1) Comply with § 60.483–1a.

(2) Comply with § 60.483–2a.

(3) Comply with the Phase III provisions in § 63.168, except an owner or operator may elect to follow the provisions in § 60.482–7a(f) instead of § 63.168 for any valve that is designated as being leakless.

(c) An owner or operator may apply to the Administrator for a determination of equivalency for any means of emission limitation that achieves a reduction in emissions of VOC at least equivalent to the reduction in emissions of VOC achieved by the controls required in this subpart. In doing so, the owner or operator shall comply with requirements of § 60.484a.

(d) Each owner or operator subject to the provisions of this subpart shall comply with the provisions of § 60.485a except as provided in § 60.593a.

(e) Each owner or operator subject to the provisions of this subpart shall comply with the provisions of §§ 60.486a and 60.487a.

**§ 60.593a Exceptions.**

(a) Each owner or operator subject to the provisions of this subpart may comply with the following exceptions to the provisions of subpart VVa of this part.

(b)(1) Compressors in hydrogen service are exempt from the requirements of § 60.592a if an owner or operator demonstrates that a compressor is in hydrogen service.

(2) Each compressor is presumed not to be in hydrogen service unless an owner or operator demonstrates that the piece of equipment is in hydrogen service. For a piece of equipment to be considered in hydrogen service, it must be determined that the percent hydrogen content can be reasonably expected always to exceed 50 percent by volume. For purposes of determining the percent hydrogen content in the process fluid that is contained in or contacts a compressor, procedures that conform to the general method described in ASTM E260–73, 91, or 96, E168–67, 77, or 92, or E169–63, 77, or 93 (incorporated by reference as specified in § 60.17) shall be used.

(3)(i) An owner or operator may use engineering judgment rather than procedures in paragraph (b)(2) of this section to demonstrate that the percent content exceeds 50 percent by volume, provided the engineering judgment demonstrates that the content clearly exceeds 50 percent by volume. When an owner or operator and the Administrator do not agree on whether a piece of equipment is in hydrogen service, however, the procedures in paragraph (b)(2) of this section shall be used to resolve the disagreement.

(ii) If an owner or operator determines that a piece of equipment is in hydrogen service, the determination can be revised only after following the procedures in paragraph (b)(2).

(c) Any existing reciprocating compressor that becomes an affected facility under provisions of § 60.14 or § 60.15 is exempt from § 60.482–3a(a), (b), (c), (d), (e), and (h) provided the owner or operator demonstrates that recasting the distance piece or replacing the compressor are the only options available to bring the compressor into compliance with the provisions of § 60.482–3a(a), (b), (c), (d), (e), and (h).

(d) An owner or operator may use the following provision in addition to § 60.485a(e): Equipment is in light liquid service if the percent evaporated is greater than 10 percent at 150 °C as determined by ASTM Method D86–78, 82, 90, 93, 95, or 96 (incorporated by reference as specified in § 60.17).

(e) Pumps in light liquid service and valves in gas/vapor and light liquid service within a process unit that is located in the Alaskan North Slope are exempt from the requirements of §§ 60.482–2a and 60.482–7a.

(f) Open-ended valves or lines containing asphalt as defined in § 60.591a are exempt from the requirements of § 60.482–6a(a) through (c).

(g) Connectors in gas/vapor or light liquid service are exempt from the requirements in § 60.482–11a, provided the owner or operator complies with § 60.482–8a for all connectors, not just those in heavy liquid service.

## PART 63—[AMENDED]

■ 27. The authority citation for part 63 continues to read as follows:

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

## Subpart A—[Amended]

■ 28. Section 63.14 is amended by revising paragraph (b)(28) to read as follows:

**§ 63.14 Incorporations by reference.**

* * * * *

(b) * * *

(28) ASTM D6420–99 (Reapproved 2004), Standards Test Method for Determination of Gaseous Organic Compounds by Direct Interface Gas Chromatography-Mass Spectometry, IBR approved for §§ 60.485(g)(5), 60.485a(g)(5), 63.772(a)(1)(ii), 63.2354(b)(3)(i), 63.2354(b)(3)(ii), 63.2354(b)(3)(ii)(A), and 63.2351(b)(3)(ii)(B).

* * * * *

[FR Doc. E7–21814 Filed 11–15–07; 8:45 am]

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Part II

# Environmental Protection Agency

40 CFR Part 60

Amendments to New Source Performance Standards (NSPS) for Electric Utility Steam Generating Units and Industrial-Commercial-Institutional Steam Generating Units; Final Rule

**ENVIRONMENTAL PROTECTION AGENCY**

**40 CFR Part 60**

**[EPA–HQ–OAR–2005–0031; FRL–8302–3]**

**RIN 2060–AN97**

# Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction Is Commenced After August 17, 1971; Standards of Performance for Electric Utility Steam Generating Units for Which Construction Is Commenced After September 18, 1978; Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units; and Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units

**AGENCY:** Environmental Protection Agency (EPA).

**ACTION:** Final reconsideration.

**SUMMARY:** EPA is amending the new source performance standards (NSPS) for electric utility steam generating units and industrial-commercial-institutional steam generating units. These amendments to the regulations are to add compliance alternatives for owners and operators of certain affected sources, revise certain recordkeeping and reporting requirements, correct technical and editorial errors, and update the grammatical style of the four subparts to be more consistent across all of the subparts.

**DATES:** This rule is effective on June 13, 2007. The incorporation by reference of certain publications listed in these rules is approved by the Director of the Federal Register as of June 13, 2007.

**ADDRESSES:** EPA has established a docket for this action under Docket ID No. EPA–HQ–OAR–2005–0031. All documents in the docket are listed in the Federal Docket Management System index at *http://www.regulations.gov*. 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 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:** Mr. Christian Fellner, Energy Strategies Group, Sector Policies and Programs Division (D243–01), U.S. EPA, Research Triangle Park, NC 27711, telephone number (919) 541–4003, facsimile number (919) 541–5450, electronic mail (e-mail) 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?*

The regulated categories and entities potentially affected by this final action include, but are not limited to, the following:

| Category | NAICS code [1] | Examples of potentially regulated entities |
|---|---|---|
| Industry | 221112 | Fossil fuel-fired electric utility steam generating units. |
| Federal Government | 22112 | Fossil fuel-fired electric utility steam generating units owned by the Federal Government. |
| State/local/tribal government | 22112 | Fossil fuel-fired electric utility steam generating units owned by municipalities. |
| | 921150 | Fossil fuel-fired electric steam generating units in Indian Country. |
| Any industrial, commercial, or institutional facility using a steam generating unit as defined in 60.40b or 60.40c. | 211 | Extractors of crude petroleum and natural gas. |
| | 321 | Manufacturers of lumber and wood products. |
| | 322 | Pulp and paper mills. |
| | 325 | Chemical manufacturers. |
| | 324 | Petroleum refiners and manufacturers of coal products. |
| | 316, 326, 339 | Manufacturers of rubber and miscellaneous plastic products. |
| | 331 | Steel works, blast furnaces. |
| | 332 | Electroplating, plating, polishing, anodizing, and coloring. |
| | 336 | Manufacturers of motor vehicle parts and accessories. |
| | 221 | Electric, gas, and sanitary services. |
| | 622 | Health services. |
| | 611 | Educational Services. |

[1] North American Industry Classification System (NAICS) code.

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 is regulated by this action, you should examine the applicability criteria in § 60.40a, 60.40b, or 60.40c of 40 CFR part 60. If you have any questions regarding the applicability of this action to a particular entity, consult either the air permit authority for the entity or your

EPA regional representative as listed in 40 CFR 63.13 of subpart A (General Provisions).

*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 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.

*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 U.S. Court of Appeals for the District of Columbia Circuit by August 13, 2007. Under section 307(d)(7)(B) of the CAA, only an objection to these final rules 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 these final rules may not be challenged separately in any civil or criminal proceedings brought by EPA to enforce these requirements.

## II. Background Information

In response to petitions for reconsideration filed by the Utility Air Regulatory Group and the Council of Industrial Boiler Owners of the amendments to the new source performance standards for steam generating units that EPA promulgated on February 27, 2006 (71 FR 9866), EPA proposed revised amendments to address issues for which the petitioners requested reconsideration (see docket entries EPA–HQ–OAR–2005–0031–0224 and EPA–HQ–OAR–2005–0031–0225). EPA proposed on February 9, 2007, (72 FR 6320) to amend 40 CFR part 60, subparts D, Da, Db, and Dc to clarify the intent for applying and implementing specific rule requirements, provide additional compliance alternatives, and to correct unintentional technical omissions and editorial errors. In addition, EPA proposed to republish 40 CFR 60.17 (Incorporations by reference) and subparts D, Da, Db, and Dc in their entirety for the purpose of revising the wording and writing style to be more consistent across all the NSPS subparts applicable to steam generating units.

A 30-day comment period (February 9, 2007 to March 12, 2007) was provided to accept comments on the proposed rule. An opportunity for a public hearing was provided to allow any interested persons to present oral comments on the proposed rule. However, EPA did not receive a request for a formal public hearing, so a public hearing was not held. EPA did receive a request for a 15-day extension to the comment period. EPA granted an extension of the public comment period to March 26, 2007 (72 FR 9903, March 6, 2007). We received comments on the proposed amendments from 20 commenters during the comment period.

## III. Final Amendments and Changes Since Proposal

We are amending 40 CFR part 60, subparts D, Da, Db, and Dc to add compliance alternatives for owners and operators of certain affected sources, revise certain recordkeeping and reporting requirements, correct technical and editorial errors, and update the grammatical style of the four subparts to be more consistent across all of the subparts. This action promulgates the proposed regulatory language for the amendments except for those significant provisions, as noted below, for which modifications were made to the regulatory language for the final amendments in response to specific public comments. EPA did not receive negative comments on the conforming changes to the regulatory text and is, therefore, finalizing all those changes.

The final amendments promulgated by this action reflect EPA's consideration of the comments received on the proposal. EPA's responses to the substantive public comments on the proposal are presented in a comment summary and response document available in Docket ID No. EPA–HQ–OAR–2005–0031.

The requirements in subpart Da for demonstrating continuous compliance with the particulate matter (PM) emission limits for affected electric utility steam generating units that commence construction, reconstruction, or modification after February 28, 2005, have been revised since proposal in response to comments. EPA is retaining the provision, established in the February 27, 2006 final rule, allowing the optional use of PM continuous emission monitoring systems (CEMS) to steam generating units for demonstration of compliance with rule requirements related to controlling PM emissions. Owners and operators choosing to install and properly operate PM CEMS must demonstrate compliance with the applicable PM emission limit on a daily basis and are not required to install a continuous opacity monitoring system (COMS) or to monitor PM control device performance.

We recognize that experience using PM CEMS at electric utility power plants in the United States is limited, and not all affected owners and operators will choose to use PM CEMS. Therefore, the final amendments allow owners and operators of affected electric utility steam generating units constructed, reconstructed, or modified after February 28, 2005, to demonstrate compliance with the PM emissions limit using periodic PM emissions performance testing and continuous monitoring of the PM control device performance using one of two alternatives. The first monitoring alternative is for an owner or operator of an affected source to monitor PM control device performance based on the opacity level measured during the stack performance test conducted to demonstrate compliance with the applicable PM emissions limit. The second alternative available to owners and operators depends on the type of PM control device used for the electric utility steam generating unit. The owner or operator of an affected source that uses an electrostatic precipitator (ESP) can elect to monitor performance of the control device using an ESP predictive emissions model. An owner or operator of an affected source that uses a fabric filter can elect to monitor control device performance using a bag leak detection system. One significant change from the proposal is that owners or operators of affected source that use parametric monitoring of PM emissions will have a grace period to bring the monitoring parameters back into the range established during the most recent PM emissions performance test prior to the requirement to conduct a new PM emissions performance test. The grace period does not apply to the 6-minute opacity standard and owners and operators of affected sources must continue to report excess 6-minute opacity measurements.

EPA has finalized several other alternatives to provide owners and operators of affected electric utility steam generating units additional flexibility in complying with the NSPS. EPA has finalized the optional use of Part 75 $NO_X$ and $SO_2$ CEMS calibration procedures to satisfy Part 60 requirements as proposed, the amendments to § 60.13 providing a standard methodology for validating partial operating hours, and the amendments to Appendix B of Part 60 allowing the calibration drift test be

conducted over 7 consecutive operating days instead of 7 consecutive calendar days and the relative accuracy test audit flexibility (as described in docket entry EPA–HQ–OAR–2005–0031–0234). In addition, EPA has finalized the option for steam generating units subject to subpart D allowing affected owners and operators to choose as an alternative to complying with the applicable $NO_X$ and $SO_2$ emission limits in the rule to comply with the 30-day average $NO_X$ and $SO_2$ standards for modified sources in subparts Da and Db, as applicable to the affected source.

For industrial/commercial/institutional steam generating units subject to subpart Db and burning coke oven gas (COG), we have expanded the applicability of the 30-day annual exemption from the $SO_2$ emissions limit to all units subject to subpart Db that burn COG. The amendments to subpart Db promulgated in February 27, 2006, added this flexibility for those steam generating units constructed, reconstructed, or modified after February 28, 2005, to account for byproduct plant maintenance. Based on comments we received, the amendments promulgated by this action provide the same compliance flexibility to the owner or operator of any COG-fired steam generating unit subject to subpart Db.

The final amendments add to subparts D, Da, Db, and Dc monitoring alternatives to existing requirements to use COMS for owners and operators of steam generating units burning gaseous fuels or low sulfur fuel oils. Owners and operators of electric utility steam generating units subject to subpart D or Da may elect to use a carbon monoxide (CO) CEMS in place of the COMS. Owners and operators of industrial/commercial/institutional steam generating units subject to subpart Db or Dc may elect to either use a CO CEMS or to operate according to a site-specific monitoring plan in place of using a COMS.

Finally, minor revisions to the proposed regulatory language were made to clarify specific provisions or to correct unintentional technical omissions and terminology, typographical, printing, and grammatical errors that were identified in the proposed rule. These changes include revising appropriate definitions and requirements in subpart Da to clarify the applicability and implementation of the subpart Da provisions to integrated coal gasification combined cycle electric utility power plants.

## IV. Statutory and Executive Order Reviews

### *A. Executive Order 12866: Regulatory Planning and 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 the Executive Order. EPA has concluded that the amendments EPA is promulgating will not change the costs or benefits of the rule.

### *B. Paperwork Reduction Act*

This action does not impose any new information collection burden under the provisions of the Paperwork Reduction Act, 44 U.S.C. 3501 *et seq.* The final amendments result in no changes to the information collection requirements of the existing standards of performance and would have no impact on the information collection estimate of projected cost and hour burden made and approved by the Office of Management and Budget (OMB) during the development of the existing standards of performance. Therefore, the information collection requests have not been amended. OMB has previously approved the information collection requirements contained in the existing standards of performance (40 CFR part 60, subparts D, Da, Db, and Dc) under the provisions of the Paperwork Reduction Act, 44 U.S.C. 3501 *et seq.*, at the time the standards were promulgated on June 11, 1979 (40 CFR part 60, subpart Da, 44 FR 33580), November 25, 1986 (40 CFR part 60, subpart Db, 51 FR 42768), and September 12, 1990 (40 CFR part 60, subpart Dc, 55 FR 37674). OMB assigned OMB control numbers 2060–0023 (ICR 1053.08) for 40 CFR part 60, subpart Da; 2060–0072 (ICR 1088.11) for 40 CFR part 60, subpart Db; 2060–0202 (ICR 1564.06) for 40 CFR part 60, subpart Dc. Copies of the information collection request document(s) may be obtained from Susan Auby, Collection Strategies Division, U.S. EPA (2822T), 1200 Pennsylvania Ave., NW., Washington, DC 20460, by e-mail at *auby.susan@epa.gov*, or by calling (202) 566–1672.

Burden means the total time, effort, or financial resources expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal agency. This includes the time needed to review instructions; develop, acquire, install, and utilize technology and systems for the purposes of collecting, validating, and verifying information, processing and maintaining information, and disclosing and providing information; adjust the existing ways to comply with any previously applicable instructions and requirements; train personnel to be able to respond to a collection of information; search data sources; complete and review the collection of information; and transmit or otherwise disclose the information.

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. OMB control numbers for EPA's regulations in 40 CFR are listed in 40 CFR part 9.

### *C. Regulatory Flexibility Act*

The Regulatory Flexibility Act generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure Act or any other statute unless the agency certifies that the rule 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 the final amendments 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 final rule on small entities, I certify that this action will not have a significant economic impact on a substantial number of small entities.

Although this action will not have a significant economic impact on a substantial number of small entities, EPA nonetheless has tried to reduce the impact of this rule on small entities. EPA is reducing the fuel usage recordkeeping requirement for subpart Dc facilities. In addition, EPA is minimizing the continuous opacity monitoring requirements for certain oil-fired facilities. EPA has, therefore, concluded that this action will relieve regulatory burden for the majority of affected small entities. EPA continues to be interested in the potential impacts of the rule on small entities and welcomes comments on issues related to such impacts.

*D. Unfunded Mandates Reform Act*

Title II of the Unfunded Mandates Reform Act of 1995 (UMRA), Public Law 104–4, establishes requirements for Federal agencies to assess the effects of their regulatory actions on State, local, and tribal governments and the private sector. Under section 202 of the UMRA, EPA generally must prepare a written statement, including a cost-benefit analysis, for proposed and final rules with "Federal mandates" that may result in expenditures to State, local, and tribal governments, in the aggregate, or to the private sector, of $100 million or more in any one year. Before promulgating an EPA rule for which a written statement is needed, section 205 of the UMRA generally requires EPA to identify and consider a reasonable number of regulatory alternatives and adopt the least costly, most cost-effective or least burdensome alternative that achieves the objectives of the rule. The provisions of section 205 do not apply when they are inconsistent with applicable law. Moreover, section 205 allows EPA to adopt an alternative other than the least costly, most cost-effective or least burdensome alternative if the Administrator publishes with the final rule an explanation why that alternative was not adopted. Before EPA establishes any regulatory requirements that may significantly or uniquely affect small governments, including tribal governments, it must have developed under section 203 of the UMRA a small government agency plan. The plan must provide for notifying potentially affected small governments, enabling officials of affected small governments to have meaningful and timely input in the development of EPA regulatory proposals with significant Federal intergovernmental mandates, and informing, educating, and advising small governments on compliance with the regulatory requirements.

EPA has determined that the final amendments will contain no Federal mandates 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 1 year. Thus, the final amendments are not subject to the requirements of section 202 and 205 of the UMRA. In addition, EPA has determined that the final amendments contain no regulatory requirements that might significantly or uniquely affect small governments because the burden is small and the regulation does not unfairly apply to small governments. Therefore, the final amendments are not subject to the requirements of section 203 of the UMRA.

*E. Executive Order 13132: Federalism*

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

The final amendments do not have federalism implications. They 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. The final amendments will not impose substantial direct compliance costs on State or local governments; it will not preempt State law. Thus, Executive Order 13132 does not apply to the final amendments.

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

Executive Order 13175, entitled "Consultation and Coordination with Indian Tribal Governments" (65 FR 67249, November 9, 2000), requires EPA to develop an accountable process to ensure "meaningful and timely input by tribal officials in the development of regulatory policies that have tribal implications." The final amendments do not have tribal implications, as specified in Executive Order 13175. While utility steam generating units are located on tribal lands EPA is not aware of any that are tribally owned. To the extend that institutional steam generating units are tribally owned the final amendments 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. Thus, Executive Order 13175 does not apply to the final amendments.

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

Executive Order 13045 (62 FR 19885, April 23, 1997) applies to any rule that: (1) Is determined to be "economically significant" as defined under Executive Order 12866, and (2) concerns an environmental health or safety risk that EPA has reason to believe may have a disproportionate effect on children. If the regulatory action meets both criteria, the Agency must evaluate the environmental health or safety effects of the planned rule on children, and explain why the planned regulation is preferable to other potentially effective and reasonably feasible alternatives considered by the Agency.

This action is not subject to the Executive Order because it is not economically significant as defined under Executive Order 12866, and because EPA interprets Executive Order 13045 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 Order has the potential to influence the regulation. The final amendments are based on technology performance and not on health or safety risks and, therefore, are not subject to Executive Order 13045.

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

The final amendments are not a "significant energy action": As defined in Executive Order 13211, "Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use" (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 because it only clarifies our intent and corrects errors in the existing rule. Further, we have concluded that the final amendments are not likely to have any adverse energy effects.

*I. National Technology Transfer Advancement Act*

Section 12(d) of the National Technology Transfer and Advancement Act of 1995 (NTTAA), Public Law 104–113, Section 12(d)(15 U.S.C. 272 note) directs us to use voluntary consensus standards in our regulatory activities unless to do so would be inconsistent with applicable law or otherwise impractical. 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 directs us to provide Congress, through OMB, explanations when we decide not use available and applicable voluntary consensus standards.

This action does not involve any new technical standards or the incorporation by reference of existing technical standards. Therefore, the consideration of voluntary consensus standards is not relevant to this action.

*J. 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. EPA will submit a report containing these final amendments 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 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 not a "major rule" as defined by 5 U.S.C. 804(2). These final amendments will be effective on June 13, 2007.

**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: April 13, 2007.

**Stephen L. Johnson,**

*Administrator.*

■ For the reasons stated in the preamble, title 40, chapter I, part 60, of the Code of the 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 60.13 is amended by revising paragraph (h) to read as follows:

### § 60.13 Monitoring requirements.

* * * * *

(h)(1) Owners or operators of all continuous monitoring systems for measurement of opacity shall reduce all data to 6-minute averages and for continuous monitoring systems other than opacity to 1-hour averages for time periods as defined in § 60.2. Six-minute opacity averages shall be calculated from 36 or more data points equally spaced over each 6-minute period.

(2) For continuous monitoring systems other than opacity, 1-hour averages shall be computed as follows, except that the provisions pertaining to the validation of partial operating hours are only applicable for affected facilities that are required by the applicable subpart to include partial hours in the emission calculations:

(i) Except as provided under paragraph (h)(2)(iii) of this section, for a full operating hour (any clock hour with 60 minutes of unit operation), at least four valid data points are required to calculate the hourly average, *i.e.*, one data point in each of the 15-minute quadrants of the hour.

(ii) Except as provided under paragraph (h)(2)(iii) of this section, for a partial operating hour (any clock hour with less than 60 minutes of unit operation), at least one valid data point in each 15-minute quadrant of the hour in which the unit operates is required to calculate the hourly average.

(iii) For any operating hour in which required maintenance or quality-assurance activities are performed:

(A) If the unit operates in two or more quadrants of the hour, a minimum of two valid data points, separated by at least 15 minutes, is required to calculate the hourly average; or

(B) If the unit operates in only one quadrant of the hour, at least one valid data point is required to calculate the hourly average.

(iv) If a daily calibration error check is failed during any operating hour, all data for that hour shall be invalidated, unless a subsequent calibration error test is passed in the same hour and the requirements of paragraph (h)(2)(iii) of this section are met, based solely on valid data recorded after the successful calibration.

(v) For each full or partial operating hour, all valid data points shall be used to calculate the hourly average.

(vi) Except as provided under paragraph (h)(2)(vii) of this section, data recorded during periods of continuous monitoring system breakdown, repair, calibration checks, and zero and span adjustments shall not be included in the data averages computed under this paragraph.

(vii) Owners and operators complying with the requirements of § 60.7(f)(1) or (2) must include any data recorded during periods of monitor breakdown or malfunction in the data averages.

(viii) When specified in an applicable subpart, hourly averages for certain partial operating hours shall not be computed or included in the emission averages (*e.g.* hours with < 30 minutes of unit operation under § 60.47b(d)).

(ix) Either arithmetic or integrated averaging of all data may be used to calculate the hourly averages. The data may be recorded in reduced or nonreduced form (*e.g.*, ppm pollutant and percent $O_2$ or ng/J of pollutant).

(3) All excess emissions shall be converted into units of the standard using the applicable conversion procedures specified in the applicable subpart. After conversion into units of the standard, the data may be rounded to the same number of significant digits used in the applicable subpart to specify the emission limit.

* * * * *

### § 60.17 [Amended]

■ 3. Section 60.17 is amended by revising paragraphs (a) and (h)(2) to read as follows:

* * * * *

(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; or ProQuest, 300 North Zeeb Road, Ann Arbor, MI 48106.

(1) ASTM A99–76, 82 (Reapproved 1987), Standard Specification for Ferromanganese, incorporation by reference (IBR) approved for § 60.261.

(2) ASTM A100–69, 74, 93, Standard Specification for Ferrosilicon, IBR approved for § 60.261.

(3) ASTM A101–73, 93, Standard Specification for Ferrochromium, IBR approved for § 60.261.

(4) ASTM A482–76, 93, Standard Specification for Ferrochromesilicon, IBR approved for § 60.261.

(5) ASTM A483–64, 74 (Reapproved 1988), Standard Specification for Silicomanganese, IBR approved for § 60.261.

(6) ASTM A495–76, 94, Standard Specification for Calcium-Silicon and Calcium Manganese-Silicon, IBR approved for § 60.261.

(7) ASTM D86–78, 82, 90, 93, 95, 96, Distillation of Petroleum Products, IBR approved for §§ 60.562–2(d), 60.593(d), and 60.633(h).

(8) ASTM D129–64, 78, 95, 00, Standard Test Method for Sulfur in Petroleum Products (General Bomb Method), IBR approved for §§ 60.106(j)(2), 60.335(b)(10)(i), and Appendix A: Method 19, 12.5.2.2.3.

(9) ASTM D129–00 (Reapproved 2005), Standard Test Method for Sulfur in Petroleum Products (General Bomb Method), IBR approved for § 60.4415(a)(1)(i).

(10) ASTM D240–76, 92, Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter, IBR approved for §§ 60.46(c), 60.296(b), and Appendix A: Method 19, Section 12.5.2.2.3.

(11) ASTM D270–65, 75, Standard Method of Sampling Petroleum and Petroleum Products, IBR approved for Appendix A: Method 19, Section 12.5.2.2.1.

(12) ASTM D323–82, 94, Test Method for Vapor Pressure of Petroleum Products (Reid Method), IBR approved for §§ 60.111(l), 60.111a(g), 60.111b(g), and 60.116b(f)(2)(ii).

(13) ASTM D388–77, 90, 91, 95, 98a, 99 (Reapproved 2004)$^{\varepsilon 1}$, Standard Specification for Classification of Coals by Rank, IBR approved for §§ 60.24(h)(8), 60.41 of subpart D of this part, 60.45(f)(4)(i), 60.45(f)(4)(ii), 60.45(f)(4)(vi), 60.41Da of subpart Da of this part, 60.41b of subpart Db of this part, 60.41c of subpart Dc of this part, and 60.4102.

(14) ASTM D388–77, 90, 91, 95, 98a, Standard Specification for Classification of Coals by Rank, IBR approved for §§ 60.251(b) and (c) of subpart Y of this part.

(15) ASTM D396–78, 89, 90, 92, 96, 98, Standard Specification for Fuel Oils, IBR approved for §§ 60.41b of subpart Db of this part, 60.41c of subpart Dc of this part, 60.111(b) of subpart K of this part, and 60.111a(b) of subpart Ka of this part.

(16) ASTM D975–78, 96, 98a, Standard Specification for Diesel Fuel Oils, IBR approved for §§ 60.111(b) of subpart K of this part and 60.111a(b) of subpart Ka of this part.

(17) ASTM D1072–80, 90 (Reapproved 1994), Standard Test Method for Total Sulfur in Fuel Gases, IBR approved for § 60.335(b)(10)(ii).

(18) ASTM D1072–90 (Reapproved 1999), Standard Test Method for Total Sulfur in Fuel Gases, IBR approved for § 60.4415(a)(1)(ii).

(19) ASTM D1137–53, 75, Standard Method for Analysis of Natural Gases and Related Types of Gaseous Mixtures by the Mass Spectrometer, IBR approved for § 60.45(f)(5)(i).

(20) ASTM D1193–77, 91, Standard Specification for Reagent Water, IBR approved for Appendix A: Method 5, Section 7.1.3; Method 5E, Section 7.2.1; Method 5F, Section 7.2.1; Method 6, Section 7.1.1; Method 7, Section 7.1.1; Method 7C, Section 7.1.1; Method 7D, Section 7.1.1; Method 10A, Section 7.1.1; Method 11, Section 7.1.3; Method 12, Section 7.1.3; Method 13A, Section 7.1.2; Method 26, Section 7.1.2; Method 26A, Section 7.1.2; and Method 29, Section 7.2.2.

(21) ASTM D1266–87, 91, 98, Standard Test Method for Sulfur in Petroleum Products (Lamp Method), IBR approved for §§ 60.106(j)(2) and 60.335(b)(10)(i).

(22) ASTM D1266–98 (Reapproved 2003)e1, Standard Test Method for Sulfur in Petroleum Products (Lamp Method), IBR approved for § 60.4415(a)(1)(i).

(23) ASTM D1475–60 (Reapproved 1980), 90, Standard Test Method for Density of Paint, Varnish Lacquer, and Related Products, IBR approved for § 60.435(d)(1), Appendix A: Method 24, Section 6.1; and Method 24A, Sections 6.5 and 7.1.

(24) ASTM D1552–83, 95, 01, Standard Test Method for Sulfur in Petroleum Products (High-Temperature Method), IBR approved for §§ 60.106(j)(2), 60.335(b)(10)(i), and Appendix A: Method 19, Section 12.5.2.2.3.

(25) ASTM D1552–03, Standard Test Method for Sulfur in Petroleum Products (High-Temperature Method), IBR approved for § 60.4415(a)(1)(i).

(26) ASTM D1826–77, 94, Standard Test Method for Calorific Value of Gases in Natural Gas Range by Continuous Recording Calorimeter, IBR approved for §§ 60.45(f)(5)(ii), 60.46(c)(2), 60.296(b)(3), and Appendix A: Method 19, Section 12.3.2.4.

(27) ASTM D1835–87, 91, 97, 03a, Standard Specification for Liquefied Petroleum (LP) Gases, IBR approved for §§ 60.41Da of subpart Da of this part, 60.41b of subpart Db of this part, and 60.41c of subpart Dc of this part.

(28) ASTM D1945–64, 76, 91, 96, Standard Method for Analysis of Natural Gas by Gas Chromatography, IBR approved for § 60.45(f)(5)(i).

(29) ASTM D1946–77, 90 (Reapproved 1994), Standard Method for Analysis of Reformed Gas by Gas Chromatography, IBR approved for §§ 60.18(f)(3), 60.45(f)(5)(i), 60.564(f)(1), 60.614(e)(2)(ii), 60.614(e)(4), 60.664(e)(2)(ii), 60.664(e)(4), 60.704(d)(2)(ii), and 60.704(d)(4).

(30) ASTM D2013–72, 86, Standard Method of Preparing Coal Samples for Analysis, IBR approved for Appendix A: Method 19, Section 12.5.2.1.3.

(31) ASTM D2015–77 (Reapproved 1978), 96, Standard Test Method for Gross Calorific Value of Solid Fuel by the Adiabatic Bomb Calorimeter, IBR approved for § 60.45(f)(5)(ii), 60.46(c)(2), and Appendix A: Method 19, Section 12.5.2.1.3.

(32) ASTM D2016–74, 83, Standard Test Methods for Moisture Content of Wood, IBR approved for Appendix A: Method 28, Section 16.1.1.

(33) ASTM D2234–76, 96, 97b, 98, Standard Methods for Collection of a Gross Sample of Coal, IBR approved for Appendix A: Method 19, Section 12.5.2.1.1.

(34) ASTM D2369–81, 87, 90, 92, 93, 95, Standard Test Method for Volatile Content of Coatings, IBR approved for Appendix A: Method 24, Section 6.2.

(35) ASTM D2382–76, 88, Heat of Combustion of Hydrocarbon Fuels by Bomb Calorimeter (High-Precision Method), IBR approved for §§ 60.18(f)(3), 60.485(g)(6), 60.564(f)(3), 60.614(e)(4), 60.664(e)(4), and 60.704(d)(4).

(36) ASTM D2504–67, 77, 88 (Reapproved 1993), Noncondensable Gases in C3 and Lighter Hydrocarbon Products by Gas Chromatography, IBR approved for § 60.485(g)(5).

(37) ASTM D2584–68 (Reapproved 1985), 94, Standard Test Method for Ignition Loss of Cured Reinforced Resins, IBR approved for § 60.685(c)(3)(i).

(38) ASTM D2597–94 (Reapproved 1999), Standard Test Method for Analysis of Demethanized Hydrocarbon Liquid Mixtures Containing Nitrogen and Carbon Dioxide by Gas Chromatography, IBR approved for § 60.335(b)(9)(i).

(39) ASTM D2622–87, 94, 98, Standard Test Method for Sulfur in Petroleum Products by Wavelength Dispersive X-Ray Fluorescence Spectrometry, IBR approved for §§ 60.106(j)(2) and 60.335(b)(10)(i).

(40) ASTM D2622–05, Standard Test Method for Sulfur in Petroleum Products by Wavelength Dispersive X-Ray Fluorescence Spectrometry, IBR approved for § 60.4415(a)(1)(i).

(41) ASTM D2879–83, 96, 97, Test Method for Vapor Pressure-Temperature Relationship and Initial Decomposition Temperature of Liquids by Isoteniscope, IBR approved for §§ 60.111b(f)(3), 60.116b(e)(3)(ii), 60.116b(f)(2)(i), and 60.485(e)(1).

(42) ASTM D2880–78, 96, Standard Specification for Gas Turbine Fuel Oils, IBR approved for §§ 60.111(b), 60.111a(b), and 60.335(d).

(43) ASTM D2908–74, 91, Standard Practice for Measuring Volatile Organic Matter in Water by Aqueous-Injection Gas Chromatography, IBR approved for § 60.564(j).

(44) ASTM D2986–71, 78, 95a, Standard Method for Evaluation of Air, Assay Media by the Monodisperse DOP (Dioctyl Phthalate) Smoke Test, IBR approved for Appendix A: Method 5, Section 7.1.1; Method 12, Section 7.1.1; and Method 13A, Section 7.1.1.2.

(45) ASTM D3173–73, 87, Standard Test Method for Moisture in the

Analysis Sample of Coal and Coke, IBR approved for Appendix A: Method 19, Section 12.5.2.1.3.

(46) ASTM D3176–74, 89, Standard Method for Ultimate Analysis of Coal and Coke, IBR approved for § 60.45(f)(5)(i) and Appendix A: Method 19, Section 12.3.2.3.

(47) ASTM D3177–75, 89, Standard Test Method for Total Sulfur in the Analysis Sample of Coal and Coke, IBR approved for Appendix A: Method 19, Section 12.5.2.1.3.

(48) ASTM D3178–73 (Reapproved 1979), 89, Standard Test Methods for Carbon and Hydrogen in the Analysis Sample of Coal and Coke, IBR approved for § 60.45(f)(5)(i).

(49) ASTM D3246–81, 92, 96, Standard Test Method for Sulfur in Petroleum Gas by Oxidative Microcoulometry, IBR approved for § 60.335(b)(10)(ii).

(50) ASTM D3246–05, Standard Test Method for Sulfur in Petroleum Gas by Oxidative Microcoulometry, IBR approved for § 60.4415(a)(1)(ii).

(51) ASTM D3270–73T, 80, 91, 95, Standard Test Methods for Analysis for Fluoride Content of the Atmosphere and Plant Tissues (Semiautomated Method), IBR approved for Appendix A: Method 13A, Section 16.1.

(52) ASTM D3286–85, 96, Standard Test Method for Gross Calorific Value of Coal and Coke by the Isoperibol Bomb Calorimeter, IBR approved for Appendix A: Method 19, Section 12.5.2.1.3.

(53) ASTM D3370–76, 95a, Standard Practices for Sampling Water, IBR approved for § 60.564(j).

(54) ASTM D3792–79, 91, Standard Test Method for Water Content of Water-Reducible Paints by Direct Injection into a Gas Chromatograph, IBR approved for Appendix A: Method 24, Section 6.3.

(55) ASTM D4017–81, 90, 96a, Standard Test Method for Water in Paints and Paint Materials by the Karl Fischer Titration Method, IBR approved for Appendix A: Method 24, Section 6.4.

(56) ASTM D4057–81, 95, Standard Practice for Manual Sampling of Petroleum and Petroleum Products, IBR approved for Appendix A: Method 19, Section 12.5.2.2.3.

(57) ASTM D4057–95 (Reapproved 2000), Standard Practice for Manual Sampling of Petroleum and Petroleum Products, IBR approved for § 60.4415(a)(1).

(58) ASTM D4084–82, 94, Standard Test Method for Analysis of Hydrogen Sulfide in Gaseous Fuels (Lead Acetate Reaction Rate Method), IBR approved for § 60.334(h)(1).

(59) ASTM D4084–05, Standard Test Method for Analysis of Hydrogen Sulfide in Gaseous Fuels (Lead Acetate Reaction Rate Method), IBR approved for §§ 60.4360 and 60.4415(a)(1)(ii).

(60) ASTM D4177–95, Standard Practice for Automatic Sampling of Petroleum and Petroleum Products, IBR approved for Appendix A: Method 19, Section 12.5.2.2.1.

(61) ASTM D4177–95 (Reapproved 2000), Standard Practice for Automatic Sampling of Petroleum and Petroleum Products, IBR approved for § 60.4415(a)(1).

(62) ASTM D4239–85, 94, 97, Standard Test Methods for Sulfur in the Analysis Sample of Coal and Coke Using High Temperature Tube Furnace Combustion Methods, IBR approved for Appendix A: Method 19, Section 12.5.2.1.3.

(63) ASTM D4294–02, Standard Test Method for Sulfur in Petroleum and Petroleum Products by Energy-Dispersive X-Ray Fluorescence Spectrometry, IBR approved for § 60.335(b)(10)(i).

(64) ASTM D4294–03, Standard Test Method for Sulfur in Petroleum and Petroleum Products by Energy-Dispersive X-Ray Fluorescence Spectrometry, IBR approved for § 60.4415(a)(1)(i).

(65) ASTM D4442–84, 92, Standard Test Methods for Direct Moisture Content Measurement in Wood and Wood-base Materials, IBR approved for Appendix A: Method 28, Section 16.1.1.

(66) ASTM D4444–92, Standard Test Methods for Use and Calibration of Hand-Held Moisture Meters, IBR approved for Appendix A: Method 28, Section 16.1.1.

(67) ASTM D4457–85 (Reapproved 1991), Test Method for Determination of Dichloromethane and 1, 1, 1-Trichloroethane in Paints and Coatings by Direct Injection into a Gas Chromatograph, IBR approved for Appendix A: Method 24, Section 6.5.

(68) ASTM D4468–85 (Reapproved 2000), Standard Test Method for Total Sulfur in Gaseous Fuels by Hydrogenolysis and Rateometric Colorimetry, IBR approved for §§ 60.335(b)(10)(ii) and 60.4415(a)(1)(ii).

(69) ASTM D4629–02, Standard Test Method for Trace Nitrogen in Liquid Petroleum Hydrocarbons by Syringe/Inlet Oxidative Combustion and Chemiluminescence Detection, IBR approved for §§ 60.49b(e) and 60.335(b)(9)(i).

(70) ASTM D4809–95, Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter (Precision Method), IBR approved for §§ 60.18(f)(3), 60.485(g)(6), 60.564(f)(3), 60.614(d)(4), 60.664(e)(4), and 60.704(d)(4).

(71) ASTM D4810–88 (Reapproved 1999), Standard Test Method for Hydrogen Sulfide in Natural Gas Using Length of Stain Detector Tubes, IBR approved for §§ 60.4360 and 60.4415(a)(1)(ii).

(72) ASTM D5287–97 (Reapproved 2002), Standard Practice for Automatic Sampling of Gaseous Fuels, IBR approved for § 60.4415(a)(1).

(73) ASTM D5403–93, Standard Test Methods for Volatile Content of Radiation Curable Materials, IBR approved for Appendix A: Method 24, Section 6.6.

(74) ASTM D5453–00, Standard Test Method for Determination of Total Sulfur in Light Hydrocarbons, Motor Fuels and Oils by Ultraviolet Fluorescence, IBR approved for § 60.335(b)(10)(i).

(75) ASTM D5453–05, Standard Test Method for Determination of Total Sulfur in Light Hydrocarbons, Motor Fuels and Oils by Ultraviolet Fluorescence, IBR approved for § 60.4415(a)(1)(i).

(76) ASTM D5504–01, Standard Test Method for Determination of Sulfur Compounds in Natural Gas and Gaseous Fuels by Gas Chromatography and Chemiluminescence, IBR approved for §§ 60.334(h)(1) and 60.4360.

(77) ASTM D5762–02, Standard Test Method for Nitrogen in Petroleum and Petroleum Products by Boat-Inlet Chemiluminescence, IBR approved for § 60.335(b)(9)(i).

(78) ASTM D5865–98, Standard Test Method for Gross Calorific Value of Coal and Coke, IBR approved for § 60.45(f)(5)(ii), 60.46(c)(2), and Appendix A: Method 19, Section 12.5.2.1.3.

(79) ASTM D6216–98, Standard Practice for Opacity Monitor Manufacturers to Certify Conformance with Design and Performance Specifications, IBR approved for Appendix B, Performance Specification 1.

(80) ASTM D6228–98, Standard Test Method for Determination of Sulfur Compounds in Natural Gas and Gaseous Fuels by Gas Chromatography and Flame Photometric Detection, IBR approved for § 60.334(h)(1).

(81) ASTM D6228–98 (Reapproved 2003), Standard Test Method for Determination of Sulfur Compounds in Natural Gas and Gaseous Fuels by Gas Chromatography and Flame Photometric Detection, IBR approved for §§ 60.4360 and 60.4415.

(82) ASTM D6348–03, Standard Test Method for Determination of Gaseous Compounds by Extractive Direct Interface Fourier Transform Infrared

(FTIR) Spectroscopy, IBR approved for table 7 of Subpart IIII of this part.

(83) ASTM D6366–99, Standard Test Method for Total Trace Nitrogen and Its Derivatives in Liquid Aromatic Hydrocarbons by Oxidative Combustion and Electrochemical Detection, IBR approved for § 60.335(b)(9)(i).

(84) ASTM D6522–00, 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, IBR approved for § 60.335(a).

(85) ASTM D6667–01, Standard Test Method for Determination of Total Volatile Sulfur in Gaseous Hydrocarbons and Liquefied Petroleum Gases by Ultraviolet Fluorescence, IBR approved for § 60.335(b)(10)(ii).

(86) ASTM D6667–04, Standard Test Method for Determination of Total Volatile Sulfur in Gaseous Hydrocarbons and Liquefied Petroleum Gases by Ultraviolet Fluorescence, IBR approved for § 60.4415(a)(1)(ii).

(87) ASTM D6784–02, Standard Test Method for Elemental, Oxidized, Particle-Bound and Total Mercury in Flue Gas Generated from Coal-Fired Stationary Sources (Ontario Hydro Method), IBR approved for Appendix B to part 60, Performance Specification 12A, Section 8.6.2.

(88) ASTM E168–67, 77, 92, General Techniques of Infrared Quantitative Analysis, IBR approved for §§ 60.593(b)(2) and 60.632(f).

(89) ASTM E169–63, 77, 93, General Techniques of Ultraviolet Quantitative Analysis, IBR approved for §§ 60.593(b)(2) and 60.632(f).

(90) ASTM E260–73, 91, 96, General Gas Chromatography Procedures, IBR approved for §§ 60.593(b)(2) and 60.632(f).

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(h) * * *

(2) ASME PTC 4.1–1964 (Reaffirmed 1991), Power Test Codes: Test Code for Steam Generating Units (with 1968 and 1969 Addenda), IBR approved for §§ 60.46b of subpart Db of this part, 60.58a(h)(6)(ii), 60.58b(i)(6)(ii), 60.1320(a)(3) and 60.1810(a)(3).

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## Subpart D—[Amended]

■ 4. Part 60 is amended by revising subpart D to read as follows:

**Subpart D—Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction Is Commenced After August 17, 1971**

Sec.



## Subpart D—Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction Is Commenced After August 17, 1971

### § 60.40 Applicability and designation of affected facility.

(a) The affected facilities to which the provisions of this subpart apply are:

(1) Each fossil-fuel-fired steam generating unit of more than 73 megawatts (MW) heat input rate (250 million British thermal units per hour (MMBtu/hr)).

(2) Each fossil-fuel and wood-residue-fired steam generating unit capable of firing fossil fuel at a heat input rate of more than 73 MW (250 MMBtu/hr).

(b) Any change to an existing fossil-fuel-fired steam generating unit to accommodate the use of combustible materials, other than fossil fuels as defined in this subpart, shall not bring that unit under the applicability of this subpart.

(c) Except as provided in paragraph (d) of this section, any facility under paragraph (a) of this section that commenced construction or modification after August 17, 1971, is subject to the requirements of this subpart.

(d) The requirements of §§ 60.44 (a)(4), (a)(5), (b) and (d), and 60.45(f)(4)(vi) are applicable to lignite-fired steam generating units that commenced construction or modification after December 22, 1976.

(e) Any facility covered under subpart Da is not covered under this subpart.

### § 60.41 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.

*Boiler operating day* means a 24-hour period between 12 midnight and the following midnight during which any fuel is combusted at any time in the steam-generating unit. It is not necessary for fuel to be combusted the entire 24-hour period.

*Coal* means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by ASTM D388 (incorporated by reference, see § 60.17).

*Coal refuse* means waste-products of coal mining, cleaning, and coal preparation operations (e.g. culm, gob, etc.) containing coal, matrix material, clay, and other organic and inorganic material.

*Fossil fuel* means natural gas, petroleum, coal, and any form of solid, liquid, or gaseous fuel derived from such materials for the purpose of creating useful heat.

*Fossil fuel and wood residue-fired steam generating unit* means a furnace or boiler used in the process of burning fossil fuel and wood residue for the purpose of producing steam by heat transfer.

*Fossil-fuel-fired steam generating unit* means a furnace or boiler used in the process of burning fossil fuel for the purpose of producing steam by heat transfer.

*Wood residue* means bark, sawdust, slabs, chips, shavings, mill trim, and other wood products derived from wood processing and forest management operations.

### § 60.42 Standard for particulate matter (PM).

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases that:

(1) Contain PM in excess of 43 nanograms per joule (ng/J) heat input (0.10 lb/MMBtu) derived from fossil fuel or fossil fuel and wood residue.

(2) Exhibit greater than 20 percent opacity except for one six-minute period per hour of not more than 27 percent opacity.

(b)(1) On or after December 28, 1979, no owner or operator shall cause to be discharged into the atmosphere from the Southwestern Public Service Company's Harrington Station #1, in Amarillo, TX, any gases which exhibit greater than 35 percent opacity, except that a maximum or 42 percent opacity shall be permitted for not more than 6 minutes in any hour.

(2) Interstate Power Company shall not cause to be discharged into the atmosphere from its Lansing Station Unit No. 4 in Lansing, IA, any gases which exhibit greater than 32 percent opacity, except that a maximum of 39 percent opacity shall be permitted for not more than six minutes in any hour.

### § 60.43 Standard for sulfur dioxide ($SO_2$).

(a) Except as provided under paragraph (d) of this section, on and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases that contain $SO_2$ in excess of:

(1) 340 ng/J heat input (0.80 lb/MMBtu) derived from liquid fossil fuel or liquid fossil fuel and wood residue.

(2) 520 ng/J heat input (1.2 lb/MMBtu) derived from solid fossil fuel or solid fossil fuel and wood residue, except as provided in paragraph (c) of this section.

(b) Except as provided under paragraph (d) of this section, when different fossil fuels are burned simultaneously in any combination, the applicable standard (in ng/J) shall be determined by proration using the following formula:

$$PS_{SO_2} = \frac{y\,(340) + z\,(520)}{(y+z)}$$

Where:

$PS_{SO_2}$ = Prorated standard for $S_{O2}$ when burning different fuels simultaneously, in ng/J heat input derived from all fossil fuels or from all fossil fuels and wood residue fired;

y = Percentage of total heat input derived from liquid fossil fuel; and

z = Percentage of total heat input derived from solid fossil fuel.

(c) Compliance shall be based on the total heat input from all fossil fuels burned, including gaseous fuels.

(d) As an alternate to meeting the requirements of paragraphs (a) and (b) of this section, an owner or operator can petition the Administrator (in writing) to comply with § 60.43Da(i)(3) of subpart Da of this part or comply with § 60.42b(k) of subpart Db of this part, as applicable to the affected source. If the Administrator grants the petition, the source will from then on (unless the unit is modified or reconstructed in the future) have to comply with the requirements in § 60.43Da(i)(3) of subpart Da of this part or § 60.42b(k) of subpart Db of this part, as applicable to the affected source.

(e) Units 1 and 2 (as defined in appendix G of this part) at the Newton Power Station owned or operated by the Central Illinois Public Service Company will be in compliance with paragraph (a)(2) of this section if Unit 1 and Unit 2 individually comply with paragraph (a)(2) of this section or if the combined emission rate from Units 1 and 2 does not exceed 470 ng/J (1.1 lb/MMBtu) combined heat input to Units 1 and 2.

### § 60.44 Standard for nitrogen oxides ($NO_X$).

(a) Except as provided under paragraph (e) of this section, on and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases that contain $NO_X$, expressed as $NO_2$ in excess of:

(1) 86 ng/J heat input (0.20 lb/MMBtu) derived from gaseous fossil fuel.

(2) 129 ng/J heat input (0.30 lb/MMBtu) derived from liquid fossil fuel, liquid fossil fuel and wood residue, or gaseous fossil fuel and wood residue.

(3) 300 ng/J heat input (0.70 lb/MMBtu) derived from solid fossil fuel or solid fossil fuel and wood residue (except lignite or a solid fossil fuel containing 25 percent, by weight, or more of coal refuse).

(4) 260 ng/J heat input (0.60 lb MMBtu) derived from lignite or lignite and wood residue (except as provided under paragraph (a)(5) of this section).

(5) 340 ng/J heat input (0.80 lb MMBtu) derived from lignite which is mined in North Dakota, South Dakota, or Montana and which is burned in a cyclone-fired unit.

(b) Except as provided under paragraphs (c), (d), and (e) of this section, when different fossil fuels are burned simultaneously in any combination, the applicable standard (in ng/J) is determined by proration using the following formula:

$$PS_{NO_X} = \frac{w\,(260) + x\,(86) + y\,(130) + z\,(300)}{(w+x+y+z)}$$

Where:

$PS_{NOx}$ = Prorated standard for $NO_X$ when burning different fuels simultaneously, in ng/J heat input derived from all fossil fuels fired or from all fossil fuels and wood residue fired;

w = Percentage of total heat input derived from lignite;

x = Percentage of total heat input derived from gaseous fossil fuel;

y = Percentage of total heat input derived from liquid fossil fuel; and

z = Percentage of total heat input derived from solid fossil fuel (except lignite).

(c) When a fossil fuel containing at least 25 percent, by weight, of coal refuse is burned in combination with gaseous, liquid, or other solid fossil fuel or wood residue, the standard for $NO_X$ does not apply.

(d) Except as provided under paragraph (e) of this section, cyclone-fired units which burn fuels containing at least 25 percent of lignite that is mined in North Dakota, South Dakota, or Montana remain subject to paragraph (a)(5) of this section regardless of the types of fuel combusted in combination with that lignite.

(e) As an alternate to meeting the requirements of paragraphs (a), (b), and (d) of this section, an owner or operator can petition the Administrator (in writing) to comply with § 60.44Da(e)(3) of subpart Da of this part. If the Administrator grants the petition, the source will from then on (unless the unit is modified or reconstructed in the future) have to comply with the requirements in § 60.44Da(e)(3) of subpart Da of this part.

### § 60.45 Emissions and fuel monitoring.

(a) Each owner or operator shall install, calibrate, maintain, and operate continuous emissions monitoring systems (CEMS) for measuring the opacity of emissions, $SO_2$ emissions, $NO_X$ emissions, and either oxygen ($O_2$) or carbon dioxide ($CO_2$) except as provided in paragraph (b) of this section.

(b) Certain of the CEMS requirements under paragraph (a) of this section do not apply to owners or operators under the following conditions:

(1) For a fossil-fuel-fired steam generator that burns only gaseous fossil fuel and that does not use post-combustion technology to reduce emissions of $SO_2$ or PM, CEMS for measuring the opacity of emissions and $SO_2$ emissions are not required.

(2) For a fossil-fuel-fired steam generator that does not use a flue gas desulfurization device, a CEMS for measuring $SO_2$ emissions is not required if the owner or operator monitors $SO_2$ emissions by fuel sampling and analysis.

(3) Notwithstanding § 60.13(b), installation of a CEMS for $NO_X$ may be delayed until after the initial performance tests under § 60.8 have been conducted. If the owner or operator demonstrates during the performance test that emissions of $NO_X$ are less than 70 percent of the applicable standards in § 60.44, a CEMS for measuring $NO_X$ emissions is not required. If the initial performance test results show that $NO_X$ emissions are greater than 70 percent of the applicable standard, the owner or operator shall install a CEMS for $NO_X$ within one year after the date of the initial performance

tests under § 60.8 and comply with all other applicable monitoring requirements under this part.

(4) If an owner or operator does not install any CEMS for sulfur oxides and $NO_X$, as provided under paragraphs (b)(1) and (b)(3) or paragraphs (b)(2) and (b)(3) of this section a CEMS for measuring either $O_2$ or $CO_2$ is not required.

(5) An owner or operator may petition the Administrator (in writing) to install a PM CEMS as an alternative to the CEMS for monitoring opacity emissions.

(6) A CEMS for measuring the opacity of emissions is not required for a fossil fuel-fired steam generator that does not use post-combustion technology (except a wet scrubber) for reducing PM, $SO_2$, or carbon monoxide (CO) emissions, burns only gaseous fuels or fuel oils that contain less than or equal to 0.30 weight percent sulfur, and is operated such that emissions of CO to the atmosphere from the affected source are maintained at levels less than or equal to 0.15 lb/MMBtu on a boiler operating day average basis. Owners and operators of affected sources electing to comply with this paragraph must demonstrate compliance according to the procedures specified in paragraphs (b)(6)(i) through (iv) of this section.

(i) You must monitor CO emissions using a CEMS according to the procedures specified in paragraphs (b)(6)(i)(A) through (D) of this section.

(A) The CO CEMS must be installed, certified, maintained, and operated according to the provisions in § 60.58b(i)(3) of subpart Eb of this part.

(B) Each 1-hour CO emissions average is calculated using the data points generated by the CO CEMS expressed in parts per million by volume corrected to 3 percent oxygen (dry basis).

(C) At a minimum, valid 1-hour CO emissions averages must be obtained for at least 90 percent of the operating hours on a 30-day rolling average basis. At least two data points per hour must be used to calculate each 1-hour average.

(D) Quarterly accuracy determinations and daily calibration drift tests for the CO CEMS must be performed in accordance with procedure 1 in appendix F of this part.

(ii) You must calculate the 1-hour average CO emissions levels for each boiler operating day by multiplying the average hourly CO output concentration measured by the CO CEMS times the corresponding average hourly flue gas flow rate and divided by the corresponding average hourly heat input to the affected source. The 24-hour average CO emission level is determined by calculating the arithmetic average of the hourly CO emission levels computed for each boiler operating day.

(iii) You must evaluate the preceding 24-hour average CO emission level each boiler operating day excluding periods of affected source startup, shutdown, or malfunction. If the 24-hour average CO emission level is greater than 0.15 lb/MMBtu, you must initiate investigation of the relevant equipment and control systems within 24 hours of the first discovery of the high emission incident and, take the appropriate corrective action as soon as practicable to adjust control settings or repair equipment to reduce the 24-hour average CO emission level to 0.15 lb/MMBtu or less.

(iv) You must record the CO measurements and calculations performed according to paragraph (b)(6) of this section and any corrective actions taken. The record of corrective action taken must include the date and time during which the 24-hour average CO emission level was greater than 0.15 lb/MMBtu, and the date, time, and description of the corrective action.

(c) For performance evaluations under § 60.13(c) and calibration checks under § 60.13(d), the following procedures shall be used:

(1) Methods 6, 7, and 3B of appendix A of this part, as applicable, shall be used for the performance evaluations of $SO_2$ and $NO_X$ continuous monitoring systems. Acceptable alternative methods for Methods 6, 7, and 3B of appendix A of this part are given in § 60.46(d).

(2) Sulfur dioxide or nitric oxide, as applicable, shall be used for preparing calibration gas mixtures under Performance Specification 2 of appendix B to this part.

(3) For affected facilities burning fossil fuel(s), the span value for a continuous monitoring system measuring the opacity of emissions shall be 80, 90, or 100 percent. For a continuous monitoring system measuring sulfur oxides or $NO_X$ the span value shall be determined using one of the following procedures:

(i) Except as provided under paragraph (c)(3)(ii) of this section, $SO_2$ and $NO_X$ span values shall be determined as follows:

| Fossil fuel | In parts per million | |
|---|---|---|
| | Span value for $SO_2$ | Span value for $NO_X$ |
| Gas | (1) | 500. |
| Liquid | 1,000 | 500. |
| Solid | 1,500 | 1,000. |
| Combinations | 1,000y + 1,500z | 500 (x + y) + 1,000z. |

[1] Not applicable.

Where:

x = Fraction of total heat input derived from gaseous fossil fuel;

y = Fraction of total heat input derived from liquid fossil fuel; and

z = Fraction of total heat input derived from solid fossil fuel.

(ii) As an alternative to meeting the requirements of paragraph (c)(3)(i) of this section, the owner or operator of an affected facility may elect to use the $SO_2$ and $NO_X$ span values determined according to sections 2.1.1 and 2.1.2 in appendix A to part 75 of this chapter.

(4) All span values computed under paragraph (c)(3)(i) of this section for burning combinations of fossil fuels shall be rounded to the nearest 500 ppm. Span values that are computed under paragraph (c)(3)(ii) of this section shall be rounded off according to the applicable procedures in section 2 of appendix A to part 75 of this chapter.

(5) For a fossil-fuel-fired steam generator that simultaneously burns fossil fuel and nonfossil fuel, the span value of all CEMS shall be subject to the Administrator's approval.

(d) [Reserved]

(e) For any CEMS installed under paragraph (a) of this section, the following conversion procedures shall be used to convert the continuous monitoring data into units of the applicable standards (ng/J, lb/MMBtu):

(1) When a CEMS for measuring $O_2$ is selected, the measurement of the pollutant concentration and $O_2$ concentration shall each be on a consistent basis (wet or dry). Alternative procedures approved by the Administrator shall be used when measurements are on a wet basis. When measurements are on a dry basis, the

following conversion procedure shall be used:

$$E = CF\left(\frac{20.9}{(20.9 - \%O_2)}\right)$$

Where E, C, F, and $\%O_2$ are determined under paragraph (f) of this section.

(2) When a CEMS for measuring $CO_2$ is selected, the measurement of the pollutant concentration and $CO_2$ concentration shall each be on a consistent basis (wet or dry) and the following conversion procedure shall be used:

$$E = CF_c\left(\frac{100}{\%CO_2}\right)$$

Where E, C, $F_c$ and $\%CO_2$ are determined under paragraph (f) of this section.

(f) The values used in the equations under paragraphs (e)(1) and (2) of this section are derived as follows:

(1) E = pollutant emissions, ng/J (lb/MMBtu).

(2) C = pollutant concentration, ng/dscm (lb/dscf), determined by multiplying the average concentration (ppm) for each one-hour period by $4.15 \times 10^4$ M ng/dscm per ppm ($2.59 \times 10^{-9}$ M lb/dscf per ppm) where M = pollutant molecular weight, g/g-mole (lb/lb-mole). M = 64.07 for $SO_2$ and 46.01 for $NO_X$.

(3) $\%O_2$, $\%CO_2$ = $O_2$ or $CO_2$ volume (expressed as percent), determined with equipment specified under paragraph (a) of this section.

(4) F, $F_c$ = a factor representing a ratio of the volume of dry flue gases generated to the calorific value of the fuel combusted (F), and a factor representing a ratio of the volume of $CO_2$ generated to the calorific value of the fuel combusted ($F_c$), respectively. Values of F and $F_c$ are given as follows:

(i) For anthracite coal as classified according to ASTM D388 (incorporated by reference, see § 60.17), F = $2,723 \times 10^{-17}$ dscm/J (10,140 dscf/MMBtu) and $F_c = 0.532 \times 10^{-17}$ scm $CO_2$/J (1,980 scf $CO_2$/MMBtu).

(ii) For subbituminous and bituminous coal as classified according to ASTM D388 (incorporated by reference, see § 60.17), F = $2.637 \times 10^{-7}$ dscm/J (9,820 dscf/MMBtu) and $F_c$ = $0.486 \times 10^{-7}$ scm $CO_2$/J (1,810 scf $CO_2$/MMBtu).

(iii) For liquid fossil fuels including crude, residual, and distillate oils, F = $2.476 \times 10^{-7}$ dscm/J (9,220 dscf/MMBtu) and $F_c = 0.384 \times 10^{-7}$ scm $CO_2$/J (1,430 scf $CO_2$/MMBtu).

(iv) For gaseous fossil fuels, F = $2.347 \times 10^{-7}$ dscm/J (8,740 dscf/MMBtu). For natural gas, propane, and butane fuels, $F_c = 0.279 \times 10^{-7}$ scm $CO_2$/J (1,040 scf $CO_2$/MMBtu) for natural gas, $0.322 \times 10^{-7}$ scm $CO_2$/J (1,200 scf $CO_2$/MMBtu) for propane, and $0.338 \times 10^{-7}$ scm $CO_2$/J (1,260 scf $CO_2$/MMBtu) for butane.

(v) For bark F = $2.589 \times 10^{-7}$ dscm/J (9,640 dscf/MMBtu) and $F_c = 0.500 \times 10^{-7}$ scm $CO_2$/J (1,840 scf $CO_2$/MMBtu). For wood residue other than bark F = $2.492 \times 10^{-7}$ dscm/J (9,280 dscf/MMBtu) and $F_c = 0.494 \times 10^{-7}$ scm $CO_2$/J (1,860 scf $CO_2$/MMBtu).

(vi) For lignite coal as classified according to ASTM D388 (incorporated by reference, see § 60.17), F = $2.659 \times 10^{-7}$ dscm/J (9,900 dscf/MMBtu) and $F_c$ = $0.516 \times 10^{-7}$ scm $CO_2$/J (1,920 scf $CO_2$/MMBtu).

(5) The owner or operator may use the following equation to determine an F factor (dscm/J or dscf/MMBtu) on a dry basis (if it is desired to calculate F on a wet basis, consult the Administrator) or Fc factor (scm $CO_2$/J, or scf $CO_2$/MMBtu) on either basis in lieu of the F or $F_c$ factors specified in paragraph (f)(4) of this section:

$$F = 10^{-6}\frac{[227.2\ (\%H) + 95.5\ (\%C) + 35.6\ (\%S) + 8.7\ (\%N) - 28.7\ (\%O)]}{GCV}$$

$$F_c = \frac{2.0 \times 10^{-5}(\%C)}{GCV\ (SI\ units)}$$

$$F = 10^{-6}\frac{[3.64\ (\%H) + 1.53\ (\%C) + 0.57\ (\%S) + 0.14\ (\%N) - 0.46\ (\%O)]}{GCV\ (English\ units)}$$

$$F_c = \frac{20.0\ (\%C)}{GCV\ (SI\ units)}$$

$$F_c = \frac{321 \times 10^3\ (\%C)}{GCV\ (English\ units)}$$

(i) %H, %C, %S, %N, and %O are content by weight of hydrogen, carbon, sulfur, nitrogen, and $O_2$ (expressed as percent), respectively, as determined on the same basis as GCV by ultimate analysis of the fuel fired, using ASTM D3178 or D3176 (solid fuels), or computed from results using ASTM D1137, D1945, or D1946 (gaseous fuels) as applicable. (These five methods are incorporated by reference, see § 60.17.)

(ii) GVC is the gross calorific value (kJ/kg, Btu/lb) of the fuel combusted determined by the ASTM test methods D2015 or D5865 for solid fuels and D1826 for gaseous fuels as applicable. (These three methods are incorporated by reference, see § 60.17.)

(iii) For affected facilities which fire both fossil fuels and nonfossil fuels, the F or Fc value shall be subject to the Administrator's approval.

(6) For affected facilities firing combinations of fossil fuels or fossil fuels and wood residue, the F or Fc factors determined by paragraphs (f)(4) or (f)(5) of this section shall be prorated in accordance with the applicable formula as follows:

$$F = \sum_{i=1}^{n} X_i F_i \quad \text{or} \quad F_c = \sum_{i=1}^{n} X_i (F_c)_i$$

Where:

$X_i$ = Fraction of total heat input derived from each type of fuel (e.g. natural gas, bituminous coal, wood residue, etc.);
$F_i$ or $(F_c)_i$ = Applicable F or $F_c$ factor for each fuel type determined in accordance with paragraphs (f)(4) and (f)(5) of this section; and
n = Number of fuels being burned in combination.

(g) Excess emission and monitoring system performance reports shall be submitted to the Administrator semiannually for each six-month period in the calendar year. All semiannual reports shall be postmarked by the 30th day following the end of each six-month period. Each excess emission and MSP report shall include the information required in § 60.7(c). Periods of excess emissions and monitoring systems (MS) downtime that shall be reported are defined as follows:

(1) *Opacity.* Excess emissions are defined as any six-minute period during which the average opacity of emissions exceeds 20 percent opacity, except that one six-minute average per hour of up to 27 percent opacity need not be reported.

(i) For sources subject to the opacity standard of § 60.42(b)(1), excess emissions are defined as any six-minute period during which the average opacity of emissions exceeds 35 percent opacity, except that one six-minute average per hour of up to 42 percent opacity need not be reported.

(ii) For sources subject to the opacity standard of § 60.42(b)(2), excess emissions are defined as any six-minute period during which the average opacity of emissions exceeds 32 percent opacity, except that one six-minute average per hour of up to 39 percent opacity need not be reported.

(2) *Sulfur dioxide.* Excess emissions for affected facilities are defined as:

(i) Any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) of $SO_2$ as measured by a CEMS exceed the applicable standard under § 60.43, or

(ii) Any 30 operating day period during which the average emissions (arithmetic average of all one-hour periods during the 30 operating days) of $SO_2$ as measured by a CEMS exceed the applicable standard under § 60.43. Facilities complying with the 30-day $SO_2$ standard shall use the most current associated $SO_2$ compliance and monitoring requirements in §§ 60.48Da and 60.49Da of subpart Da of this part.

(3) *Nitrogen oxides.* Excess emissions for affected facilities using a CEMS for measuring $NO_X$ are defined as:

(i) Any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) exceed the applicable standards under § 60.44, or

(ii) Any 30 operating day period during which the average emissions (arithmetic average of all one-hour periods during the 30 operating days) of $NO_X$ as measured by a CEMS exceed the applicable standard under § 60.43. Facilities complying with the 30-day $NO_X$ standard shall use the most current associated $NO_X$ compliance and monitoring requirements in §§ 60.48Da and 60.49Da of subpart Da of this part.

(4) *Particulate matter.* Excess emissions for affected facilities using a CEMS for measuring PM are defined as any boiler operating day period during which the average emissions (arithmetic average of all operating one-hour periods) exceed the applicable standards under § 60.43. Affected facilities using PM CEMS in lieu of a CEMS for monitoring opacity emissions must follow the most current applicable compliance and monitoring provisions in §§ 60.48Da and 60.49Da of subpart Da of this part.

**§ 60.46 Test methods and procedures.**

(a) In conducting the performance tests required in § 60.8, and subsequent performance tests as requested by the EPA Administrator, the owner or operator shall use as reference methods and procedures 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). Acceptable alternative methods and procedures are given in paragraph (d) of this section.

(b) The owner or operator shall determine compliance with the PM, $SO_2$, and $NO_X$ standards in §§ 60.42, 60.43, and 60.44 as follows:

(1) The emission rate (E) of PM, $SO_2$, or $NO_X$ shall be computed for each run using the following equation:

$$E = CF_d\left(\frac{20.9}{(20.9 - \%O_2)}\right)$$

Where:
E = Emission rate of pollutant, ng/J (1b/million Btu);
C = Concentration of pollutant, ng/dscm (1b/dscf);
$\%O_2$ = $O_2$ concentration, percent dry basis; and
$F_d$ = Factor as determined from Method 19 of appendix A of this part.

(2) Method 5 of appendix A of this part shall be used to determine the PM concentration (C) at affected facilities without wet flue-gas-desulfurization (FGD) systems and Method 5B of appendix A of this part shall be used to determine the PM concentration (C) after FGD systems.

(i) The sampling time and sample volume for each run shall be at least 60 minutes and 0.85 dscm (30 dscf). The probe and filter holder heating systems in the sampling train shall be set to provide an average gas temperature of 160±14 °C (320±25 °F).

(ii) The emission rate correction factor, integrated or grab sampling and analysis procedure of Method 3B of appendix A of this part shall be used to determine the $O_2$ concentration ($\%O_2$). The $O_2$ sample shall be obtained simultaneously with, and at the same traverse points as, the particulate sample. If the grab sampling procedure is used, the $O_2$ concentration for the run shall be the arithmetic mean of the sample $O_2$ concentrations at all traverse points.

(iii) If the particulate run has more than 12 traverse points, the $O_2$ traverse points may be reduced to 12 provided that Method 1 of appendix A of this part is used to locate the 12 $O_2$ traverse points.

(3) Method 9 of appendix A of this part and the procedures in § 60.11 shall be used to determine opacity.

(4) Method 6 of appendix A of this part shall be used to determine the $SO_2$ concentration.

(i) The sampling site shall be the same as that selected for the particulate sample. The sampling location in the duct shall be at the centroid of the cross section or at a point no closer to the walls than 1 m (3.28 ft). The sampling time and sample volume for each sample run shall be at least 20 minutes and 0.020 dscm (0.71 dscf). Two samples shall be taken during a 1-hour period, with each sample taken within a 30-minute interval.

(ii) The emission rate correction factor, integrated sampling and analysis procedure of Method 3B of appendix A of this part shall be used to determine the $O_2$ concentration ($\%O_2$). The $O_2$ sample shall be taken simultaneously with, and at the same point as, the $SO_2$ sample. The $SO_2$ emission rate shall be computed for each pair of $SO_2$ and $O_2$ samples. The $SO_2$ emission rate (E) for each run shall be the arithmetic mean of the results of the two pairs of samples.

(5) Method 7 of appendix A of this part shall be used to determine the $NO_X$ concentration.

(i) The sampling site and location shall be the same as for the $SO_2$ sample. Each run shall consist of four grab samples, with each sample taken at about 15-minute intervals.

(ii) For each $NO_X$ sample, the emission rate correction factor, grab sampling and analysis procedure of

Method 3B of appendix A of this part shall be used to determine the $O_2$ concentration ($\%O_2$). The sample shall be taken simultaneously with, and at the same point as, the $NO_X$ sample.

(iii) The $NO_X$ emission rate shall be computed for each pair of $NO_X$ and $O_2$ samples. The $NO_X$ emission rate (E) for each run shall be the arithmetic mean of the results of the four pairs of samples.

(c) When combinations of fossil fuels or fossil fuel and wood residue are fired, the owner or operator (in order to compute the prorated standard as shown in §§ 60.43(b) and 60.44(b)) shall determine the percentage (w, x, y, or z) of the total heat input derived from each type of fuel as follows:

(1) The heat input rate of each fuel shall be determined by multiplying the gross calorific value of each fuel fired by the rate of each fuel burned.

(2) ASTM Methods D2015, or D5865 (solid fuels), D240 (liquid fuels), or D1826 (gaseous fuels) (all of these methods are incorporated by reference, see § 60.17) shall be used to determine the gross calorific values of the fuels. The method used to determine the calorific value of wood residue must be approved by the Administrator.

(3) Suitable methods shall be used to determine the rate of each fuel burned during each test period, and a material balance over the steam generating system shall be used to confirm the rate.

(d) The owner or operator may use the following as alternatives to the reference methods and procedures in this section or in other sections as specified:

(1) The emission rate (E) of PM, $SO_2$ and $NO_X$ may be determined by using the Fc factor, provided that the following procedure is used:

(i) The emission rate (E) shall be computed using the following equation:

$$E = CF_c\left(\frac{100}{\%CO_2}\right)$$

Where:

E = Emission rate of pollutant, ng/J (lb/MMBtu);

C = Concentration of pollutant, ng/dscm (lb/dscf);

$\%CO_2 = CO_2$ concentration, percent dry basis; and

$F_c$ = Factor as determined in appropriate sections of Method 19 of appendix A of this part.

(ii) If and only if the average Fc factor in Method 19 of appendix A of this part is used to calculate E and either E is from 0.97 to 1.00 of the emission standard or the relative accuracy of a continuous emission monitoring system is from 17 to 20 percent, then three runs of Method 3B of appendix A of this part shall be used to determine the $O_2$ and $CO_2$ concentration according to the procedures in paragraph (b)(2)(ii), (4)(ii), or (5)(ii) of this section. Then if $F_o$ (average of three runs), as calculated from the equation in Method 3B of appendix A of this part, is more than ±3 percent than the average $F_o$ value, as determined from the average values of $F_d$ and $F_c$ in Method 19 of appendix A of this part, *i.e.*, $F_{oa} = 0.209\ (F_{da}/F_{ca})$, then the following procedure shall be followed:

(A) When $F_o$ is less than 0.97 $F_{oa}$, then E shall be increased by that proportion under 0.97 $F_{oa}$, *e.g.*, if $F_o$ is 0.95 $F_{oa}$, E shall be increased by 2 percent. This recalculated value shall be used to determine compliance with the emission standard.

(B) When $F_o$ is less than 0.97 $F_{oa}$ and when the average difference (d) between the continuous monitor minus the reference methods is negative, then E shall be increased by that proportion under 0.97 $F_{oa}$, *e.g.*, if $F_o$ is 0.95 $F_{oa}$, E shall be increased by 2 percent. This recalculated value shall be used to determine compliance with the relative accuracy specification.

(C) When $F_o$ is greater than 1.03 $F_{oa}$ and when the average difference d is positive, then E shall be decreased by that proportion over 1.03 $F_{oa}$, *e.g.*, if $F_o$ is 1.05 $F_{oa}$, E shall be decreased by 2 percent. This recalculated value shall be used to determine compliance with the relative accuracy specification.

(2) For Method 5 or 5B of appendix A of this part, Method 17 of appendix A of this part may be used at facilities with or without wet FGD systems if the stack gas temperature at the sampling location does not exceed an average temperature of 16 0°C (320 °F). The procedures of sections 2.1 and 2.3 of Method 5B of appendix A of this part may be used with Method 17 of appendix A of this part only if it is used after wet FGD systems. Method 17 of appendix A of this part shall not be used after wet FGD systems if the effluent gas is saturated or laden with water droplets.

(3) Particulate matter and $SO_2$ may be determined simultaneously with the Method 5 of appendix A of this part train provided that the following changes are made:

(i) The filter and impinger apparatus in sections 2.1.5 and 2.1.6 of Method 8 of appendix A of this part is used in place of the condenser (section 2.1.7) of Method 5 of appendix A of this part.

(ii) All applicable procedures in Method 8 of appendix A of this part for the determination of $SO_2$ (including moisture) are used:

(4) For Method 6 of appendix A of this part, Method 6C of appendix A of this part may be used. Method 6A of appendix A of this part may also be used whenever Methods 6 and 3B of appendix A of this part data are specified to determine the $SO_2$ emission rate, under the conditions in paragraph (d)(1) of this section.

(5) For Method 7 of appendix A of this part, Method 7A, 7C, 7D, or 7E of appendix A of this part may be used. If Method 7C, 7D, or 7E of appendix A of this part is used, the sampling time for each run shall be at least 1 hour and the integrated sampling approach shall be used to determine the $O_2$ concentration ($\%O_2$) for the emission rate correction factor.

(6) For Method 3 of appendix A of this part, Method 3A or 3B of appendix A of this part may be used.

(7) For Method 3B of appendix A of this part, Method 3A of appendix A of this part may be used.

## Subpart Da—[Amended]

■ 4a. Subpart Da is revised as follows:

### Subpart Da—Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978

Sec.



### Subpart Da—Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978

#### § 60.40Da Applicability and designation of affected facility.

(a) The affected facility to which this subpart applies is each electric utility steam generating unit:

(1) That is capable of combusting more than 73 megawatts (MW) (250 million British thermal units per hour (MMBtu/hr) heat input of fossil fuel (either alone or in combination with any other fuel); and

(2) For which construction, modification, or reconstruction is commenced after September 18, 1978.

(b) Combined cycle gas turbines (both the stationary combustion turbine and any associated duct burners) are subject to this part and not subject to subpart GG or KKKK of this part if:

(1) The combined cycle gas turbine is capable of combusting more than 73 MW (250 MMBtu/hr) heat input of fossil fuel (either alone or in combination with any other fuel); and

(2) The combined cycle gas turbine is designed and intended to burn fuels containing 50 percent (by heat input) or more solid-derived fuel not meeting the definition of natural gas on a 12-month rolling average basis; and

(3) The combined cycle gas turbine commenced construction, modification, or reconstruction after February 28, 2005.

(4) This subpart will continue to apply to all other electric utility combined cycle gas turbines that are capable of combusting more than 73 MW (250 MMBtu/hr) heat input of fossil fuel in the heat recovery steam generator. If the heat recovery steam generator is subject to this subpart and the stationary combustion turbine is subject to either subpart GG or KKKK of this part, only emissions resulting from combustion of fuels in the steam-generating unit are subject to this subpart. (The stationary combustion turbine emissions are subject to subpart GG or KKKK, as applicable, of this part).

(c) Any change to an existing fossil-fuel-fired steam generating unit to accommodate the use of combustible materials, other than fossil fuels, shall not bring that unit under the applicability of this subpart.

(d) Any change to an existing steam generating unit originally designed to fire gaseous or liquid fossil fuels, to accommodate the use of any other fuel (fossil or nonfossil) shall not bring that unit under the applicability of this subpart.

**§ 60.41Da 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.

*Anthracite* means coal that is classified as anthracite according to the American Society of Testing and Materials in ASTM D388 (incorporated by reference, see § 60.17).

*Available purchase power* means the lesser of the following:

(a) The sum of available system capacity in all neighboring companies.

(b) The sum of the rated capacities of the power interconnection devices between the principal company and all neighboring companies, minus the sum of the electric power load on these interconnections.

(c) The rated capacity of the power transmission lines between the power interconnection devices and the electric generating units (the unit in the principal company that has the malfunctioning flue gas desulfurization system and the unit(s) in the neighboring company supplying replacement electrical power) less the electric power load on these transmission lines.

*Available system capacity means* the capacity determined by subtracting the system load and the system emergency reserves from the net system capacity.

*Biomass* means plant materials and animal waste.

*Bituminous coal* means coal that is classified as bituminous according to the American Society of Testing and Materials in ASTM D388 (incorporated by reference, see § 60.17).

*Boiler operating day* for units constructed, reconstructed, or modified on or before February 28, 2005, means a 24-hour period during which fossil fuel is combusted in a steam-generating unit for the entire 24 hours. For units constructed, reconstructed, or modified after February 28, 2005, *boiler operating day* means a 24-hour period between 12 midnight and the following midnight during which any fuel is combusted at any time in the steam-generating unit. It is not necessary for fuel to be combusted the entire 24-hour period.

*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 (not meeting the definition of natural gas), coal-oil mixtures, and coal-water mixtures are included in this definition for the purposes of this subpart.

*Coal-fired electric utility steam generating unit* means an electric utility steam generating unit that burns coal, coal refuse, or a synthetic gas derived from coal either exclusively, in any combination together, or in any combination with other fuels in any amount.

*Coal refuse* means waste products of coal mining, physical coal cleaning, and coal preparation operations (*e.g.* culm, gob, etc.) containing coal, matrix material, clay, and other organic and inorganic material.

*Cogeneration, also known as "combined heat and power,"* means a steam-generating unit that simultaneously produces both electric (or mechanical) and useful thermal energy from the same primary energy source.

*Combined cycle gas turbine* means a stationary turbine combustion system where heat from the turbine exhaust gases is recovered by a steam generating unit.

*Dry flue gas desulfurization technology* or *dry FGD* means a sulfur dioxide control system that is located downstream of the steam generating unit and removes sulfur oxides ($SO_2$) from the combustion gases of the steam generating unit by contacting the combustion gases with an alkaline reagent and water, whether introduced separately or as a premixed slurry or solution and forming a dry powder material. This definition includes devices where the dry powder material is subsequently converted to another form. Alkaline slurries or solutions used in dry FGD technology include, but are not limited to, lime and sodium.

*Duct burner* means a device that combusts fuel and that is placed in the exhaust duct from another source, such as a stationary gas turbine, internal combustion engine, kiln, etc., to allow the firing of additional fuel to heat the exhaust gases before the exhaust gases enter a heat recovery steam generating unit.

*Electric utility combined cycle gas turbine* means any combined cycle gas turbine used for electric generation that is constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MW net-electrical output to any utility power distribution system for sale. Any steam distribution system that is constructed for the purpose of providing steam to a steam electric generator that would produce electrical power for sale is also considered in determining the electrical energy output capacity of the affected facility.

*Electric utility company* means the largest interconnected organization, business, or governmental entity that generates electric power for sale (*e.g.*, a holding company with operating subsidiary companies).

*Electric utility steam-generating unit* means any steam electric generating unit that is constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MW net-electrical output to any utility power distribution system for sale. Also, any steam supplied to a steam distribution system for the purpose of providing steam to a steam-electric generator that would produce electrical energy for sale is considered in determining the electrical energy output capacity of the affected facility.

*Electrostatic precipitator* or *ESP* means an add-on air pollution control device used to capture particulate matter (PM) by charging the particles using an electrostatic field, collecting the particles using a grounded collecting surface, and transporting the particles into a hopper.

*Emergency condition* means that period of time when:

(1) The electric generation output of an affected facility with a malfunctioning flue gas desulfurization system cannot be reduced or electrical output must be increased because:

(i) All available system capacity in the principal company interconnected with the affected facility is being operated, and

(ii) All available purchase power interconnected with the affected facility is being obtained, or

(2) The electric generation demand is being shifted as quickly as possible from an affected facility with a malfunctioning flue gas desulfurization system to one or more electrical generating units held in reserve by the principal company or by a neighboring company, or

(3) An affected facility with a malfunctioning flue gas desulfurization system becomes the only available unit to maintain a part or all of the principal company's system emergency reserves and the unit is operated in spinning reserve at the lowest practical electric generation load consistent with not causing significant physical damage to the unit. If the unit is operated at a higher load to meet load demand, an emergency condition would not exist unless the conditions under paragraph (1) of this definition apply.

*Emission limitation* means any emissions limit or operating limit.

*Emission rate period* means any calendar month included in a 12-month rolling average period.

*Federally enforceable* means all limitations and conditions that are enforceable by the Administrator, including the requirements of 40 CFR parts 60 and 61, requirements within any applicable State implementation plan, and any permit requirements established under 40 CFR 52.21 or under 40 CFR 51.18 and 51.24.

*Fossil fuel* means natural gas, petroleum, coal, and any form of solid, liquid, or gaseous fuel derived from such material for the purpose of creating useful heat.

*Gaseous fuel* means any fuel derived from coal or petroleum that is present as a gas at standard conditions and includes, but is not limited to, refinery fuel gas, process gas, coke-oven gas, synthetic gas, and gasified coal.

*Gross output* means the gross useful work performed by the steam generated and, for an IGCC electric utility steam generating unit, the fuel burned in stationary combustion turbines. For a unit generating only electricity, the gross useful work performed is the gross electrical output from the unit's turbine/generator sets. For a cogeneration unit, the gross useful work performed is the gross electrical or mechanical output plus 75 percent of the useful thermal output measured relative to ISO conditions that is not used to generate additional electrical or mechanical output (i.e., steam delivered to an industrial process).

*24-hour period* means the period of time between 12:01 a.m. and 12:00 midnight.

*Integrated gasification combined cycle electric utility steam generating unit* or *IGCC electric utility steam generating unit* means a coal-fired electric utility steam generating unit that burns a synthetic gas derived from coal in a combined-cycle gas turbine. No coal is directly burned in the unit during operation.

*Interconnected* means that two or more electric generating units are electrically tied together by a network of power transmission lines, and other power transmission equipment.

*ISO conditions* means a temperature of 288 Kelvin, a relative humidity of 60 percent, and a pressure of 101.3 kilopascals.

*Lignite* means coal that is classified as lignite A or B according to the American Society of Testing and Materials in ASTM D388 (incorporated by reference, see § 60.17).

*Natural gas* means:

(1) A naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane; or

(2) Liquid petroleum gas, as defined by the American Society of Testing and Materials in ASTM D1835 (incorporated by reference, see § 60.17); or

(3) A mixture of hydrocarbons that maintains a gaseous state at ISO conditions. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 34 and 43 megajoules (MJ) per standard cubic meter (910 and 1,150 Btu per standard cubic foot).

*Neighboring company* means any one of those electric utility companies with one or more electric power interconnections to the principal company and which have geographically adjoining service areas.

*Net-electric output* means the gross electric sales to the utility power distribution system minus purchased power on a calendar year basis.

*Net system capacity* means the sum of the net electric generating capability (not necessarily equal to rated capacity) of all electric generating equipment owned by an electric utility company (including steam generating units, internal combustion engines, gas turbines, nuclear units, hydroelectric units, and all other electric generating equipment) plus firm contractual purchases that are interconnected to the affected facility that has the malfunctioning flue gas desulfurization system. The electric generating capability of equipment under multiple ownership is prorated based on ownership unless the proportional entitlement to electric output is otherwise established by contractual arrangement.

*Noncontinental area* means the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, or the Northern Mariana Islands.

*Petroleum* means crude oil or petroleum or a fuel derived from crude oil or petroleum, including, but not limited to, distillate oil, residual oil, and petroleum coke.

*Potential combustion concentration* means the theoretical emissions (nanograms per joule (ng/J), lb/MMBtu heat input) that would result from combustion of a fuel in an uncleaned state without emission control systems) and:

(1) For particulate matter (PM) is:

(i) 3,000 ng/J (7.0 lb/MMBtu) heat input for solid fuel; and

(ii) 73 ng/J (0.17 lb/MMBtu) heat input for liquid fuels.

(2) For sulfur dioxide ($SO_2$) is determined under § 60.50Da(c).

(3) For nitrogen oxides ($NO_X$) is:

(i) 290 ng/J (0.67 lb/MMBtu) heat input for gaseous fuels;

(ii) 310 ng/J (0.72 lb/MMBtu) heat input for liquid fuels; and

(iii) 990 ng/J (2.30 lb/MMBtu) heat input for solid fuels.

*Potential electrical output capacity* means 33 percent of the maximum design heat input capacity of the steam generating unit, divided by 3,413 Btu/KWh, divided by 1,000 kWh/MWh, and multiplied by 8,760 hr/yr (*e.g.*, a steam generating unit with a 100 MW (340 MMBtu/hr) fossil-fuel heat input capacity would have a 289,080 MWh 12 month potential electrical output capacity). For electric utility combined cycle gas turbines the potential electrical output capacity is determined on the basis of the fossil-fuel firing

capacity of the steam generator exclusive of the heat input and electrical power contribution by the gas turbine.

*Principal company* means the electric utility company or companies which own the affected facility.

*Resource recovery unit* means a facility that combusts more than 75 percent non-fossil fuel on a quarterly (calendar) heat input basis.

*Responsible official* means responsible official as defined in 40 CFR 70.2.

*Solid-derived fuel* means any solid, liquid, or gaseous fuel derived from solid fuel for the purpose of creating useful heat and includes, but is not limited to, solvent refined coal, liquified coal, synthetic gas, gasified coal, gasified petroleum coke, gasified biomass, and gasified tire derived fuel.

*Spare flue gas desulfurization system module* means a separate system of $SO_2$ emission control equipment capable of treating an amount of flue gas equal to the total amount of flue gas generated by an affected facility when operated at maximum capacity divided by the total number of nonspare flue gas desulfurization modules in the system.

*Spinning reserve* means the sum of the unutilized net generating capability of all units of the electric utility company that are synchronized to the power distribution system and that are capable of immediately accepting additional load. The electric generating capability of equipment under multiple ownership is prorated based on ownership unless the proportional entitlement to electric output is otherwise established by contractual arrangement.

*Steam generating unit* means any furnace, boiler, or other device used for combusting fuel for the purpose of producing steam (including fossil-fuel-fired steam generators associated with combined cycle gas turbines; nuclear steam generators are not included).

*Subbituminous coal* means coal that is classified as subbituminous A, B, or C according to the American Society of Testing and Materials in ASTM D388 (incorporated by reference, see § 60.17).

*System emergency reserves* means an amount of electric generating capacity equivalent to the rated capacity of the single largest electric generating unit in the electric utility company (including steam generating units, internal combustion engines, gas turbines, nuclear units, hydroelectric units, and all other electric generating equipment) which is interconnected with the affected facility that has the malfunctioning flue gas desulfurization system. The electric generating capability of equipment under multiple ownership is prorated based on ownership unless the proportional entitlement to electric output is otherwise established by contractual arrangement.

*System load* means the entire electric demand of an electric utility company's service area interconnected with the affected facility that has the malfunctioning flue gas desulfurization system plus firm contractual sales to other electric utility companies. Sales to other electric utility companies (*e.g.*, emergency power) not on a firm contractual basis may also be included in the system load when no available system capacity exists in the electric utility company to which the power is supplied for sale.

*Wet flue gas desulfurization technology* or *wet FGD* means a $SO_2$ control system that is located downstream of the steam generating unit and removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gases with an alkaline slurry or solution and forming a liquid material. This definition applies to devices where the aqueous liquid material product of this contact is subsequently converted to other forms. Alkaline reagents used in wet FGD technology include, but are not limited to, lime, limestone, and sodium.

**§ 60.42Da Standard for particulate matter (PM).**

(a) 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, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility for which construction, reconstruction, or modification commenced before or on February 28, 2005, any gases that contain PM in excess of:

(1) 13 ng/J (0.03 lb/MMBtu) heat input derived from the combustion of solid, liquid, or gaseous fuel;

(2) 1 percent of the potential combustion concentration (99 percent reduction) when combusting solid fuel; and

(3) 30 percent of potential combustion concentration (70 percent reduction) when combusting liquid fuel.

(b) On and after the date the initial PM performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases which exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity.

(c) Except as provided in paragraph (d) 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, no owner or operator of an affected facility that commenced construction, reconstruction, or modification after February 28, 2005 shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of either:

(1) 18 ng/J (0.14 lb/MWh) gross energy output; or

(2) 6.4 ng/J (0.015 lb/MMBtu) heat input derived from the combustion of solid, liquid, or gaseous fuel.

(d) As an alternative to meeting the requirements of paragraph (c) of this section, the owner or operator of an affected facility for which construction, reconstruction, or modification commenced after February 28, 2005, may elect to meet the requirements of this paragraph. 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, no owner or operator of an affected facility shall cause to be discharged into the atmosphere from that affected facility for which construction, reconstruction, or modification commenced after February 28, 2005, any gases that contain PM in excess of:

(1) 13 ng/J (0.03 lb/MMBtu) heat input derived from the combustion of solid, liquid, or gaseous fuel, and

(2) 0.1 percent of the combustion concentration determined according to the procedure in § 60.48Da(o)(5) (99.9 percent reduction) for an affected facility for which construction or reconstruction commenced after February 28, 2005 when combusting solid, liquid, or gaseous fuel, or

(3) 0.2 percent of the combustion concentration determined according to the procedure in § 60.48Da(o)(5) (99.8 percent reduction) for an affected facility for which modification commenced after February 28, 2005 when combusting solid, liquid, or gaseous fuel.

**§ 60.43Da Standard for sulfur dioxide ($SO_2$).**

(a) 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, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility which combusts solid fuel or

solid-derived fuel and for which construction, reconstruction, or modification commenced before or on February 28, 2005, except as provided under paragraphs (c), (d), (f) or (h) of this section, any gases that contain $SO_2$ in excess of:

(1) 520 ng/J (1.20 lb/MMBtu) heat input and 10 percent of the potential combustion concentration (90 percent reduction); or

(2) 30 percent of the potential combustion concentration (70 percent reduction), when emissions are less than 260 ng/J (0.60 lb/MMBtu) heat input.

(b) 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, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility which combusts liquid or gaseous fuels (except for liquid or gaseous fuels derived from solid fuels and as provided under paragraphs (e) or (h) of this section) and for which construction, reconstruction, or modification commenced before or on February 28, 2005, any gases that contain $SO_2$ in excess of:

(1) 340 ng/J (0.80 lb/MMBtu) heat input and 10 percent of the potential combustion concentration (90 percent reduction); or

(2) 100 percent of the potential combustion concentration (zero percent reduction) when emissions are less than 86 ng/J (0.20 lb/MMBtu) heat input.

(c) 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, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility which combusts solid solvent refined coal (SRC–I) any gases that contain $SO_2$ in excess of 520 ng/J (1.20 lb/MMBtu) heat input and 15 percent of the potential combustion concentration (85 percent reduction) except as provided under paragraph (f) of this section; compliance with the emission limitation is determined on a 30-day rolling average basis and compliance with the percent reduction requirement is determined on a 24-hour basis.

(d) Sulfur dioxide emissions are limited to 520 ng/J (1.20 lb/MMBtu) heat input from any affected facility which:

(1) Combusts 100 percent anthracite;

(2) Is classified as a resource recovery unit; or

(3) Is located in a noncontinental area and combusts solid fuel or solid-derived fuel.

(e) Sulfur dioxide emissions are limited to 340 ng/J (0.80 lb/MMBtu) heat input from any affected facility which is located in a noncontinental area and combusts liquid or gaseous fuels (excluding solid-derived fuels).

(f) The emission reduction requirements under this section do not apply to any affected facility that is operated under an $SO_2$ commercial demonstration permit issued by the Administrator in accordance with the provisions of § 60.47Da.

(g) Compliance with the emission limitation and percent reduction requirements under this section are both determined on a 30-day rolling average basis except as provided under paragraph (c) of this section.

(h) When different fuels are combusted simultaneously, the applicable standard is determined by proration using the following formula:

(1) If emissions of $SO_2$ to the atmosphere are greater than 260 ng/J (0.60 lb/MMBtu) heat input

$$E_s = \frac{(340x + 520y)}{100} \quad \text{and} \quad \%P_s = 10$$

(2) If emissions of $SO_2$ to the atmosphere are equal to or less than 260 ng/J (0.60 lb/MMBtu) heat input:

$$E_s = \frac{(340x + 520y)}{100} \quad \text{and} \quad \%P_s = \frac{(10x + 30y)}{100}$$

Where:

$E_s$ = Prorated $SO_2$ emission limit (ng/J heat input);

$\%P_s$ = Percentage of potential $SO_2$ emission allowed;

x = Percentage of total heat input derived from the combustion of liquid or gaseous fuels (excluding solid-derived fuels); and

y = Percentage of total heat input derived from the combustion of solid fuel (including solid-derived fuels).

(i) Except as provided in paragraphs (j) and (k) 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, no owner or operator of an affected facility that commenced construction, reconstruction, or modification commenced after February 28, 2005 shall cause to be discharged into the atmosphere from that affected facility, any gases that contain $SO_2$ in excess of the applicable emission limitation specified in paragraphs (i)(1) through (3) of this section.

(1) For an affected facility for which construction commenced after February 28, 2005, any gases that contain $SO_2$ in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output on a 30-day rolling average basis; or

(ii) 5 percent of the potential combustion concentration (95 percent reduction) on a 30-day rolling average basis.

(2) For an affected facility for which reconstruction commenced after February 28, 2005, any gases that contain $SO_2$ in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output on a 30-day rolling average basis;

(ii) 65 ng/J (0.15 lb/MMBtu) heat input on a 30-day rolling average basis; or

(iii) 5 percent of the potential combustion concentration (95 percent reduction) on a 30-day rolling average basis.

(3) For an affected facility for which modification commenced after February 28, 2005, any gases that contain $SO_2$ in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output on a 30-day rolling average basis;

(ii) 65 ng/J (0.15 lb/MMBtu) heat input on a 30-day rolling average basis; or

(iii) 10 percent of the potential combustion concentration (90 percent reduction) on a 30-day rolling average basis.

(j) 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, no owner or operator of an affected facility that commenced construction, reconstruction, or modification commenced after February 28, 2005, and that burns 75 percent or more (by heat input) coal refuse on a 12-month rolling average basis, shall caused to be discharged into the atmosphere from that affected facility any gases that contain $SO_2$ in excess of the applicable emission limitation specified in paragraphs (j)(1) through (3) of this section.

(1) For an affected facility for which construction commenced after February

28, 2005, any gases that contain $SO_2$ in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output on a 30-day rolling average basis; or

(ii) 6 percent of the potential combustion concentration (94 percent reduction) on a 30-day rolling average basis.

(2) For an affected facility for which reconstruction commenced after February 28, 2005, any gases that contain $SO_2$ in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output on a 30-day rolling average basis;

(ii) 65 ng/J (0.15 lb/MMBtu) heat input on a 30-day rolling average basis; or

(iii) 6 percent of the potential combustion concentration (94 percent reduction) on a 30-day rolling average basis.

(3) For an affected facility for which modification commenced after February 28, 2005, any gases that contain $SO_2$ in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output on a 30-day rolling average basis;

(ii) 65 ng/J (0.15 lb/MMBtu) heat input on a 30-day rolling average basis; or

(iii) 10 percent of the potential combustion concentration (90 percent reduction) on a 30-day rolling average basis.

(k) 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, no owner or operator of an affected facility located in a noncontinental area that commenced construction, reconstruction, or modification commenced after February 28, 2005, shall cause to be discharged into the atmosphere from that affected facility any gases that contain $SO_2$ in excess of the applicable emission limitation specified in paragraphs (k)(1) and (2) of this section.

(1) For an affected facility that burns solid or solid-derived fuel, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain $SO_2$ in excess of 520 ng/J (1.2 lb/MMBtu) heat input on a 30-day rolling average basis.

(2) For an affected facility that burns other than solid or solid-derived fuel, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain $SO_2$ in excess of if the affected facility or 230 ng/J (0.54 lb/MMBtu) heat input on a 30-day rolling average basis.

**§ 60.44Da Standard for nitrogen oxides ($NO_X$).**

(a) 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, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility, except as provided under paragraphs (b), (d), (e), and (f) of this section, any gases that contain $NO_X$ (expressed as $NO_2$) in excess of the following emission limits, based on a 30-day rolling average basis, except as provided under § 60.48Da(j)(1):

(1) $NO_X$ emission limits.

| Fuel type | Emission limit for heat input | |
|---|---|---|
| | ng/J | lb/MMBtu |
| Gaseous fuels: | | |
| Coal-derived fuels | 210 | 0.50 |
| All other fuels | 86 | 0.20 |
| Liquid fuels: | | |
| Coal-derived fuels | 210 | 0.50 |
| Shale oil | 210 | 0.50 |
| All other fuels | 130 | 0.30 |
| Solid fuels: | | |
| Coal-derived fuels | 210 | 0.50 |
| Any fuel containing more than 25%, by weight, coal refuse | [1] | [1] |
| Any fuel containing more than 25%, by weight, lignite if the lignite is mined in North Dakota, South Dakota, or Montana, and is combusted in a slag tap furnace [2] | 340 | 0.80 |
| Any fuel containing more than 25%, by weight, lignite not subject to the 340 ng/J heat input emission limit [2] | 260 | 0.60 |
| Subbituminous coal | 210 | 0.50 |
| Bituminous coal | 260 | 0.60 |
| Anthracite coal | 260 | 0.60 |
| All other fuels | 260 | 0.60 |

[1] Exempt from $NO_X$ standards and $NO_X$ monitoring requirements.
[2] Any fuel containing less than 25%, by weight, lignite is not prorated but its percentage is added to the percentage of the predominant fuel.

(2) $NO_X$ reduction requirement.

| Fuel type | Percent reduction of potential combustion concentration |
|---|---|
| Gaseous fuels | 25 |
| Liquid fuels | 30 |
| Solid fuels | 65 |

(b) The emission limitations under paragraph (a) of this section do not apply to any affected facility which is combusting coal-derived liquid fuel and is operating under a commercial demonstration permit issued by the Administrator in accordance with the provisions of § 60.47Da.

(c) Except as provided under paragraphs (d), (e), and (f) of this section, when two or more fuels are combusted simultaneously, the applicable standard is determined by proration using the following formula:

$$E_n = \frac{(86w + 130x + 210y + 260z + 340v)}{100}$$

Where:

$E_n$ = Applicable standard for $NO_X$ when multiple fuels are combusted simultaneously (ng/J heat input);

w = Percentage of total heat input derived from the combustion of fuels subject to the 86 ng/J heat input standard;

x = Percentage of total heat input derived from the combustion of fuels subject to the 130 ng/J heat input standard;

y = Percentage of total heat input derived from the combustion of fuels subject to the 210 ng/J heat input standard;

z = Percentage of total heat input derived from the combustion of fuels subject to the 260 ng/J heat input standard; and

v = Percentage of total heat input delivered from the combustion of fuels subject to the 340 ng/J heat input standard.

(d)(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, no owner or operator of an affected facility that commenced construction after July 9, 1997, but before or on February 28, 2005 shall cause to be discharged into the atmosphere any gases that contain $NO_X$ (expressed as $NO_2$) in excess of 200 ng/J (1.6 lb/MWh) gross energy output, based on a 30-day rolling average basis, except as provided under § 60.48Da(k).

(2) 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, no owner or operator of affected facility for which reconstruction commenced after July 9, 1997, but before or on February 28, 2005 shall cause to be discharged into the atmosphere any gases that contain $NO_X$ (expressed as $NO_2$) in excess of 65 ng/J (0.15 lb/MMBtu) heat input, based on a 30-day rolling average basis.

(e) Except for an IGCC electric utility steam generating unit meeting the requirements of 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, no owner or operator of an affected facility that commenced construction, reconstruction, or modification after February 28, 2005 shall cause to be discharged into the atmosphere from that affected facility any gases that contain $NO_X$ (expressed as $NO_2$) in excess of the applicable emission limitation specified in paragraphs (e)(1) through (3) of this section.

(1) For an affected facility for which construction commenced after February 28, 2005, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain $NO_X$ (expressed as $NO_2$) in excess of 130 ng/J (1.0 lb/MWh) gross energy output on a 30-day rolling average basis, except as provided under § 60.48Da(k).

(2) For an affected facility for which reconstruction commenced after February 28, 2005, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain $NO_X$ (expressed as $NO_2$) in excess of either:

(i) 130 ng/J (1.0 lb/MWh) gross energy output on a 30-day rolling average basis; or

(ii) 47 ng/J (0.11 lb/MMBtu) heat input on a 30-day rolling average basis.

(3) For an affected facility for which modification commenced after February 28, 2005, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain $NO_X$ (expressed as $NO_2$) in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output on a 30-day rolling average basis; or

(ii) 65 ng/J (0.15 lb/MMBtu) heat input on a 30-day rolling average basis.

(f) 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 of an IGCC electric utility steam generating unit subject to the provisions of this subpart and for which construction, reconstruction, or modification commenced after February 28, 2005, shall meet the requirements specified in paragraphs (f)(1) through (3) of this section.

(1) Except as provided for in paragraphs (f)(2) and (3) of this section, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain $NO_X$ (expressed as $NO_2$) in excess of 130 ng/J (1.0 lb/MWh) gross energy output on a 30-day rolling average basis.

(2) When burning liquid fuel exclusively or in combination with solid-derived fuel such that the liquid fuel contributes 50 percent or more of the total heat input to the combined cycle combustion turbine, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain $NO_X$ (expressed as $NO_2$) in excess of 190 ng/J (1.5 lb/MWh) gross energy output on a 30-day rolling average basis.

(3) In cases when during a 30-day rolling average compliance period liquid fuel is burned in such a manner to meet the conditions in paragraph (f)(2) of this section for only a portion of the clock hours in the 30-day period, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain $NO_X$ (expressed as $NO_2$) in excess of the computed weighted-average emissions limit based on the proportion of gross energy output (in MWh) generated during the compliance period for each of emissions limits in paragraphs (f)(1) and (2) of this section.

**§ 60.45Da Standard for mercury (Hg).**

(a) For each coal-fired electric utility steam generating unit other than an IGCC electric utility steam generating unit, 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, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility for which construction, modification, or reconstruction commenced after January 30, 2004, any gases that contain mercury (Hg) emissions in excess of each Hg emissions limit in paragraphs (a)(1) through (5) of this section that applies to you. The Hg emissions limits in paragraphs (a)(1) through (5) of this section are based on a 12-month rolling average basis using the procedures in § 60.50Da(h).

(1) For each coal-fired electric utility steam generating unit that burns only bituminous coal, you must not discharge into the atmosphere any gases from a new affected source that contain Hg in excess of $20 \times 10^{-6}$ pound per megawatt hour (lb/MWh) or 0.020 lb/gigawatt-hour (GWh) on an output basis. The International System of Units (SI) equivalent is 0.0025 ng/J.

(2) For each coal-fired electric utility steam generating unit that burns only subbituminous coal:

(i) If your unit is located in a county-level geographical area receiving greater than 25 inches per year (in/yr) mean annual precipitation, based on the most recent publicly available U.S. Department of Agriculture 30-year data, you must not discharge into the atmosphere any gases from a new affected source that contain Hg in excess of $66 \times 10^{-6}$ lb/MWh or 0.066 lb/GWh on an output basis. The SI equivalent is 0.0083 ng/J.

(ii) If your unit is located in a county-level geographical area receiving less than or equal to 25 in/yr mean annual precipitation, based on the most recent publicly available U.S. Department of Agriculture 30-year data, you must not discharge into the atmosphere any gases from a new affected source that contain Hg in excess of $97 \times 10^{-6}$ lb/MWh or 0.097 lb/GWh on an output basis. The SI equivalent is 0.0122 ng/J.

(3) For each coal-fired electric utility steam generating unit that burns only lignite, you must not discharge into the atmosphere any gases from a new affected source that contain Hg in excess of $175 \times 10^{-6}$ lb/MWh or 0.175 lb/GWh on an output basis. The SI equivalent is 0.0221 ng/J.

(4) For each coal-burning electric utility steam generating unit that burns only coal refuse, you must not discharge into the atmosphere any gases from a new affected source that contain Hg in excess of $16 \times 10^{-6}$ lb/MWh or 0.016 lb/GWh on an output basis. The SI equivalent is 0.0020 ng/J.

(5) For each coal-fired electric utility steam generating unit that burns a blend of coals from different coal ranks (*i.e.*, bituminous coal, subbituminous coal, lignite) or a blend of coal and coal refuse, you must not discharge into the atmosphere any gases from a new affected source that contain Hg in excess of the unit-specific Hg emissions limit

established according to paragraph (a)(5)(i) or (ii) of this section, as applicable to the affected unit.

(i) If you operate a coal-fired electric utility steam generating unit that burns a blend of coals from different coal ranks or a blend of coal and coal refuse, you must not discharge into the atmosphere any gases from a new affected source that contain Hg in excess of the computed weighted Hg emissions limit based on the Btu, MWh, or MJ) contributed by each coal rank burned during the compliance period and its applicable Hg emissions limit in paragraphs (a)(1) through (4) of this section as determined using Equation 1 in this section. For each affected source, you must comply with the weighted Hg emissions limit calculated using Equation 1 in this section based on the total Hg emissions from the unit and the total Btu, MWh, or MJ contributed by all fuels burned during the compliance period.

$$EL_b = \frac{\sum_{i=1}^{n} EL_i (HH_i)}{\sum_{i=1}^{n} HH_i} \quad \text{(Eq. 1)}$$

Where:

$EL_b$ = Total allowable Hg in lb/MWh that can be emitted to the atmosphere from any affected source being averaged according to this paragraph.

$EL_i$ = Hg emissions limit for the subcategory i (coal rank) that applies to affected source, lb/MWh;

$HH_i$ = For each affected source, the Btu, MWh, or MJ contributed by the corresponding subcategory i (coal rank) burned during the compliance period; and

n = Number of subcategories (coal ranks) being averaged for an affected source.

(ii) If you operate a coal-fired electric utility steam generating unit that burns a blend of coals from different coal ranks or a blend of coal and coal refuse together with one or more non-regulated, supplementary fuels, you must not discharge into the atmosphere any gases from a new affected source that contain Hg in excess of the computed weighted Hg emission limit based on the Btu, MWh, or MJ contributed by each coal rank burned during the compliance period and its applicable Hg emissions limit in paragraphs (a)(1) through (4) of this section as determined using Equation 1 in this section. For each affected source. You must comply with the weighted Hg emissions limit calculated using Equation 1 in this section based on the total Hg emissions from the unit contributed by both regulated and nonregulated fuels burned during the compliance period and the total Btu, MWh, or MJ contributed by both regulated and nonregulated fuels burned during the compliance period.

(b) For each IGCC electric utility steam generating unit, on and after the date on which the initial performance test required to be conducted under § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility for which construction, modification, or reconstruction commenced after January 30, 2004, any gases that contain Hg emissions in excess of $20 \times 10^{-6}$ lb/MWh or 0.020 lb/GWh on an output basis. The SI equivalent is 0.0025 ng/J. This Hg emissions limit is based on a 12-month rolling average basis using the procedures in § 60.50Da(h).

**§ 60.46Da [Reserved]**

**§ 60.47Da Commercial demonstration permit.**

(a) An owner or operator of an affected facility proposing to demonstrate an emerging technology may apply to the Administrator for a commercial demonstration permit. The Administrator will issue a commercial demonstration permit in accordance with paragraph (e) of this section. Commercial demonstration permits may be issued only by the Administrator, and this authority will not be delegated.

(b) An owner or operator of an affected facility that combusts solid solvent refined coal (SRC–I) and who is issued a commercial demonstration permit by the Administrator is not subject to the $SO_2$ emission reduction requirements under § 60.43Da(c) but must, as a minimum, reduce $SO_2$ emissions to 20 percent of the potential combustion concentration (80 percent reduction) for each 24-hour period of steam generator operation and to less than 520 ng/J (1.20 lb/MMBtu) heat input on a 30-day rolling average basis.

(c) An owner or operator of a fluidized bed combustion electric utility steam generator (atmospheric or pressurized) who is issued a commercial demonstration permit by the Administrator is not subject to the $SO_2$ emission reduction requirements under § 60.43Da(a) but must, as a minimum, reduce $SO_2$ emissions to 15 percent of the potential combustion concentration (85 percent reduction) on a 30-day rolling average basis and to less than 520 ng/J (1.20 lb/MMBtu) heat input on a 30-day rolling average basis.

(d) The owner or operator of an affected facility that combusts coal-derived liquid fuel and who is issued a commercial demonstration permit by the Administrator is not subject to the applicable $NO_X$ emission limitation and percent reduction under § 60.44Da(a) but must, as a minimum, reduce emissions to less than 300 ng/J (0.70 lb/MMBtu) heat input on a 30-day rolling average basis.

(e) Commercial demonstration permits may not exceed the following equivalent MW electrical generation capacity for any one technology category, and the total equivalent MW electrical generation capacity for all commercial demonstration plants may not exceed 15,000 MW.

| Technology | Pollutant | Equivalent electrical capacity (MW electrical output) |
|---|---|---|
| Solid solvent refined coal (SCR I) | $SO_2$ | 6,000–10,000 |
| Fluidized bed combustion (atmospheric) | $SO_2$ | 400–3,000 |
| Fluidized bed combustion (pressurized) | $SO_2$ | 400–1,200 |
| Coal liquification | $NO_X$ | 750–10,000 |
| Total allowable for all technologies | ..... | 15,000 |

**§ 60.48Da Compliance provisions.**

(a) Compliance with the PM emission limitation under § 60.42Da(a)(1) constitutes compliance with the percent reduction requirements for PM under § 60.42Da(a)(2) and (3).

(b) Compliance with the $NO_X$ emission limitation under § 60.44Da(a)(1) constitutes compliance with the percent reduction requirements under § 60.44Da(a)(2).

(c) The PM emission standards under § 60.42Da, the $NO_X$ emission standards under § 60.44Da, and the Hg emission standards under § 60.45Da apply at all times except during periods of startup, shutdown, or malfunction.

(d) During emergency conditions in the principal company, an affected facility with a malfunctioning flue gas desulfurization system may be operated if $SO_2$ emissions are minimized by:

(1) Operating all operable flue gas desulfurization system modules, and bringing back into operation any malfunctioned module as soon as repairs are completed,

(2) Bypassing flue gases around only those flue gas desulfurization system modules that have been taken out of operation because they were incapable of any $SO_2$ emission reduction or which would have suffered significant physical damage if they had remained in operation, and

(3) Designing, constructing, and operating a spare flue gas desulfurization system module for an affected facility larger than 365 MW (1,250 MMBtu/hr) heat input (approximately 125 MW electrical output capacity). The Administrator may at his discretion require the owner or operator within 60 days of notification to demonstrate spare module capability. To demonstrate this capability, the owner or operator must demonstrate compliance with the appropriate requirements under paragraph under § 60.43Da(a), (b), (d), (e), and (h) for any period of operation lasting from 24 hours to 30 days when:

(i) Any one flue gas desulfurization module is not operated,

(ii) The affected facility is operating at the maximum heat input rate,

(iii) The fuel fired during the 24-hour to 30-day period is representative of the type and average sulfur content of fuel used over a typical 30-day period, and

(iv) The owner or operator has given the Administrator at least 30 days notice of the date and period of time over which the demonstration will be performed.

(e) After the initial performance test required under § 60.8, compliance with the $SO_2$ emission limitations and percentage reduction requirements under § 60.43Da and the $NO_X$ emission limitations under § 60.44Da is based on the average emission rate for 30 successive boiler operating days. A separate performance test is completed at the end of each boiler operating day after the initial performance test, and a new 30 day average emission rate for both $SO_2$ and $NO_X$ and a new percent reduction for $SO_2$ are calculated to show compliance with the standards.

(f) For the initial performance test required under § 60.8, compliance with the $SO_2$ emission limitations and percent reduction requirements under § 60.43Da and the $NO_X$ emission limitation under § 60.44Da is based on the average emission rates for $SO_2$, $NO_X$, and percent reduction for $SO_2$ for the first 30 successive boiler operating days. The initial performance test is the only test in which at least 30 days prior notice is required unless otherwise specified by the Administrator. The initial performance test is to be scheduled so that the first boiler operating day of the 30 successive boiler operating days is completed within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of the facility.

(g) The owner or operator of an affected facility subject to emission limitations in this subpart shall determine compliance as follows:

(1) Compliance with applicable 30-day rolling average $SO_2$ and $NO_X$ emission limitations is determined by calculating the arithmetic average of all hourly emission rates for $SO_2$ and $NO_X$ for the 30 successive boiler operating days, except for data obtained during startup, shutdown, malfunction ($NO_X$ only), or emergency conditions ($SO_2$ only).

(2) Compliance with applicable $SO_2$ percentage reduction requirements is determined based on the average inlet and outlet $SO_2$ emission rates for the 30 successive boiler operating days.

(3) Compliance with applicable daily average PM emission limitations is determined by calculating the arithmetic average of all hourly emission rates for PM each boiler operating day, except for data obtained during startup, shutdown, and malfunction. Averages are only calculated for boiler operating days that have valid data for at least 18 hours of unit operation during which the standard applies. Instead, the valid hourly emission rates are averaged with the next boiler operating day with 18 hours or more of valid PM CEMS data to determine compliance.

(h) If an owner or operator has not obtained the minimum quantity of emission data as required under § 60.49Da of this subpart, compliance of the affected facility with the emission requirements under §§ 60.43Da and 60.44Da of this subpart for the day on which the 30-day period ends may be determined by the Administrator by following the applicable procedures in section 7 of Method 19 of appendix A of this part.

(i) *Compliance provisions for sources subject to § 60.44Da(d)(1), (e)(1), (e)(2)(i), (e)(3)(i), or (f).* The owner or operator of an affected facility subject to § 60.44Da(d)(1), (e)(1), (e)(2)(i), (e)(3)(i), or (f) shall calculate $NO_X$ emissions as $1.194 \times 10^{-7}$ lb/scf-ppm times the average hourly $NO_X$ output concentration in ppm (measured according to the provisions of § 60.49Da(c)), times the average hourly flow rate (measured in scfh, according to the provisions of § 60.49Da(l) or § 60.49Da(m)), divided by the average hourly gross energy output (measured according to the provisions of § 60.49Da(k)). Alternatively, for oil-fired and gas-fired units, $NO_X$ emissions may be calculated by multiplying the hourly $NO_X$ emission rate in lb/MMBtu (measured by the CEMS required under §§ 60.49Da(c) and (d)), by the hourly heat input rate (measured according to the provisions of § 60.49Da(n)), and dividing the result by the average gross energy output (measured according to the provisions of § 60.49Da(k)).

(j) *Compliance provisions for duct burners subject to § 60.44Da(a)(1).* To determine compliance with the emissions limits for $NO_X$ required by § 60.44Da(a) for duct burners used in combined cycle systems, either of the procedures described in paragraph (j)(1) or (2) of this section may be used:

(1) The owner or operator of an affected duct burner shall conduct the performance test required under § 60.8 using the appropriate methods in appendix A of this part. Compliance with the emissions limits under § 60.44Da(a)(1) is determined on the average of three (nominal 1-hour) runs for the initial and subsequent performance tests. During the performance test, one sampling site shall be located in the exhaust of the turbine prior to the duct burner. A second sampling site shall be located at the outlet from the heat recovery steam generating unit. Measurements shall be taken at both sampling sites during the performance test; or

(2) The owner or operator of an affected duct burner may elect to determine compliance by using the continuous emission monitoring system (CEMS) specified under § 60.49Da for measuring $NO_X$ and oxygen ($O_2$) (or carbon dioxide ($CO_2$)) and meet the requirements of § 60.49Da. Alternatively, data from a $NO_X$ emission rate (*i.e.*, $NO_X$-diluent) CEMS certified according to the provisions of § 75.20(c) of this chapter and appendix A to part 75 of this chapter, and meeting the quality assurance requirements of § 75.21 of this chapter and appendix B to part 75 of this chapter, may be used,

with the following caveats. Data used to meet the requirements of § 60.51Da shall not include substitute data values derived from the missing data procedures in subpart D of part 75 of this chapter, nor shall the data have been bias adjusted according to the procedures of part 75 of this chapter. The sampling site shall be located at the outlet from the steam generating unit. The $NO_X$ emission rate at the outlet from the steam generating unit shall constitute the $NO_X$ emission rate from the duct burner of the combined cycle system.

(k) *Compliance provisions for duct burners subject to § 60.44Da(d)(1) or (e)(1).* To determine compliance with the emission limitation for $NO_X$ required by § 60.44Da(d)(1) or (e)(1) for duct burners used in combined cycle systems, either of the procedures described in paragraphs (k)(1) and (2) of this section may be used:

(1) The owner or operator of an affected duct burner used in combined cycle systems shall determine compliance with the applicable $NO_X$ emission limitation in § 60.44Da(d)(1) or (e)(1) as follows:

(i) The emission rate (E) of $NO_X$ shall be computed using Equation 2 in this section:

$$E = \frac{(C_{sg} \times Q_{sg}) - (C_{te} \times Q_{te})}{(O_{sg} \times h)} \qquad \text{(Eq. 2)}$$

Where:

E = Emission rate of $NO_X$ from the duct burner, ng/J (lb/MWh) gross output;
$C_{sg}$ = Average hourly concentration of $NO_X$ exiting the steam generating unit, ng/dscm (lb/dscf);
$C_{tc}$ = Average hourly concentration of $NO_X$ in the turbine exhaust upstream from duct burner, ng/dscm (lb/dscf);
$Q_{sg}$ = Average hourly volumetric flow rate of exhaust gas from steam generating unit, dscm/hr (dscf/hr);
$Q_{te}$ = Average hourly volumetric flow rate of exhaust gas from combustion turbine, dscm/hr (dscf/hr);
$O_{sg}$ = Average hourly gross energy output from steam generating unit, J (MWh); and
h = Average hourly fraction of the total heat input to the steam generating unit derived from the combustion of fuel in the affected duct burner.

(ii) Method 7E of appendix A of this part shall be used to determine the $NO_X$ concentrations ($C_{sg}$ and $C_{te}$). Method 2, 2F or 2G of appendix A of this part, as appropriate, shall be used to determine the volumetric flow rates ($Q_{sg}$ and $Q_{te}$) of the exhaust gases. The volumetric flow rate measurements shall be taken at the same time as the concentration measurements.

(iii) The owner or operator shall develop, demonstrate, and provide information satisfactory to the Administrator to determine the average hourly gross energy output from the steam generating unit, and the average hourly percentage of the total heat input to the steam generating unit derived from the combustion of fuel in the affected duct burner.

(iv) Compliance with the applicable $NO_X$ emission limitation in § 60.44Da(d)(1) or (e)(1) is determined by the three-run average (nominal 1-hour runs) for the initial and subsequent performance tests.

(2) The owner or operator of an affected duct burner used in a combined cycle system may elect to determine compliance with the applicable $NO_X$ emission limitation in § 60.44Da(d)(1) or (e)(1) on a 30-day rolling average basis as indicated in paragraphs (k)(2)(i) through (iv) of this section.

(i) The emission rate (E) of $NO_X$ shall be computed using Equation 3 in this section:

$$E = \frac{(C_{sg} \times Q_{sd})}{O_{cc}} \qquad \text{(Eq. 3)}$$

Where:

E = Emission rate of $NO_X$ from the duct burner, ng/J (lb/MWh) gross output;
$C_{sg}$ = Average hourly concentration of $NO_X$ exiting the steam generating unit, ng/dscm (lb/dscf);
$Q_{sg}$ = Average hourly volumetric flow rate of exhaust gas from steam generating unit, dscm/hr (dscf/hr); and
$O_{cc}$ = Average hourly gross energy output from entire combined cycle unit, J (MWh).

(ii) The CEMS specified under § 60.49Da for measuring $NO_X$ and $O_2$ (or $CO_2$) shall be used to determine the average hourly $NO_X$ concentrations ($C_{sg}$). The continuous flow monitoring system specified in § 60.49Da(l) or § 60.49Da(m) shall be used to determine the volumetric flow rate ($Q_{sg}$) of the exhaust gas. If the option to use the flow monitoring system in § 60.49Da(m) is selected, the flow rate data used to meet the requirements of § 60.51Da shall not include substitute data values derived from the missing data procedures in subpart D of part 75 of this chapter, nor shall the data have been bias adjusted according to the procedures of part 75 of this chapter. The sampling site shall be located at the outlet from the steam generating unit.

(iii) The continuous monitoring system specified under § 60.49Da(k) for measuring and determining gross energy output shall be used to determine the average hourly gross energy output from the entire combined cycle unit ($O_{cc}$), which is the combined output from the combustion turbine and the steam generating unit.

(iv) The owner or operator may, in lieu of installing, operating, and recording data from the continuous flow monitoring system specified in § 60.49Da(l), determine the mass rate (lb/hr) of $NO_X$ emissions by installing, operating, and maintaining continuous fuel flowmeters following the appropriate measurements procedures specified in appendix D of part 75 of this chapter. If this compliance option is selected, the emission rate (E) of $NO_X$ shall be computed using Equation 4 in this section:

$$E = \frac{(ER_{sg} \times H_{cc})}{O_{cc}} \qquad \text{(Eq. 4)}$$

Where:

E = Emission rate of $NO_X$ from the duct burner, ng/J (lb/MWh) gross output;
$ER_{sg}$ = Average hourly emission rate of $NO_X$ exiting the steam generating unit heat input calculated using appropriate F factor as described in Method 19 of appendix A of this part, ng/J (lb/MMBtu);
$H_{cc}$ = Average hourly heat input rate of entire combined cycle unit, J/hr (MMBtu/hr); and
$O_{cc}$ = Average hourly gross energy output from entire combined cycle unit, J (MWh).

(3) When an affected duct burner steam generating unit utilizes a common steam turbine with one or more affected duct burner steam generating units, the owner or operator shall either:

(i) Determine compliance with the applicable $NO_X$ emissions limits by measuring the emissions combined with the emissions from the other unit(s) utilizing the common steam turbine; or

(ii) Develop, demonstrate, and provide information satisfactory to the Administrator on methods for apportioning the combined gross energy output from the steam turbine for each of the affected duct burners. The Administrator may approve such demonstrated substitute methods for apportioning the combined gross energy output measured at the steam turbine whenever the demonstration ensures accurate estimation of emissions regulated under this part.

(l) *Compliance provisions for sources subject to § 60.45Da.* The owner or operator of an affected facility subject to § 60.45Da (new sources constructed or reconstructed after January 30, 2004) shall calculate the Hg emission rate (lb/MWh) for each calendar month of the year, using hourly Hg concentrations measured according to the provisions of § 60.49Da(p) in conjunction with hourly stack gas volumetric flow rates

measured according to the provisions of § 60.49Da(l) or (m), and hourly gross electrical outputs, determined according to the provisions in § 60.49Da(k). Compliance with the applicable standard under § 60.45Da is determined on a 12-month rolling average basis.

(m) *Compliance provisions for sources subject to § 60.43Da(i)(1)(i), (i)(2)(i), (i)(3)(i), (j)(1)(i), (j)(2)(i), or (j)(3)(i).* The owner or operator of an affected facility subject to § 60.43Da(i)(1)(i), (i)(2)(i), (i)(3)(i), (j)(1)(i), (j)(2)(i), or (j)(3)(i) shall calculate $SO_2$ emissions as $1.660 \times 10^{-7}$ lb/scf-ppm times the average hourly $SO_2$ output concentration in ppm (measured according to the provisions of § 60.49Da(b)), times the average hourly flow rate (measured according to the provisions of § 60.49Da(l) or § 60.49Da(m)), divided by the average hourly gross energy output (measured according to the provisions of § 60.49Da(k)). Alternatively, for oil-fired and gas-fired units, $SO_2$ emissions may be calculated by multiplying the hourly $SO_2$ emission rate (in lb/MMBtu), measured by the CEMS required under § 60.49Da, by the hourly heat input rate (measured according to the provisions of § 60.49Da(n)), and dividing the result by the average gross energy output (measured according to the provisions of § 60.49Da(k)).

(n) *Compliance provisions for sources subject to § 60.42Da(c)(1).* The owner or operator of an affected facility subject to § 60.42Da(c)(1) shall calculate PM emissions by multiplying the average hourly PM output concentration, measured according to the provisions of § 60.49Da(t), by the average hourly flow rate, measured according to the provisions of § 60.49Da(l), and divided by the average hourly gross energy output, measured according to the provisions of § 60.49Da(k). Compliance with the emission limit is determined by calculating the arithmetic average of the hourly emission rates computed for each boiler operating day.

(o) *Compliance provisions for sources subject to § 60.42Da(c)(2) or (d).* Except as provided for in paragraph (p) of this section, the owner or operator of an affected facility for which construction, reconstruction, or modification commenced after February 28, 2005, shall demonstrate compliance with each applicable emission limit according to the requirements in paragraphs (o)(1) through (o)(5) of this section and use a COMS to demonstrate compliance with § 60.42Da(b).

(1) You must conduct a performance test to demonstrate initial compliance with the applicable PM emissions limit in 60.42Da(c)(2) or (d) by the applicable date specified in § 60.8(a). Thereafter, you must conduct each subsequent performance test within 12 calendar months of the date of the prior performance test. You must conduct each performance test according to the requirements in § 60.8 using the test methods and procedures in § 60.50Da.

(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(c)(2) or (d) 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.

(i) Each COMS must meet Performance Specification 1 in 40 CFR part 60, appendix B.

(ii) You must comply with the quality assurance requirements in paragraphs (o)(4)(ii)(A) through (E) of this section.

(A) You must automatically (intrinsic to the opacity monitor) check the zero and upscale (span) calibration drifts at least once daily. For a particular COMS, the acceptable range of zero and upscale calibration materials is as defined in the applicable version of Performance Specification 1 in 40 CFR part 60, appendix B.

(B) You must adjust the zero and span whenever the 24-hour zero drift or 24-hour span drift exceeds 4 percent opacity. The COMS must allow for the amount of excess zero and span drift measured at the 24-hour interval checks to be recorded and quantified. The optical surfaces exposed to the effluent gases must be cleaned prior to performing the zero and span drift adjustments, except for systems using automatic zero adjustments. For systems using automatic zero adjustments, the optical surfaces must be cleaned when the cumulative automatic zero compensation exceeds 4 percent opacity.

(C) You must apply a method for producing a simulated zero opacity condition and an upscale (span) opacity condition using a certified neutral density filter or other related technique to produce a known obscuration of the light beam. All procedures applied must provide a system check of the analyzer internal optical surfaces and all electronic circuitry including the lamp and photodetector assembly.

(D) Except during periods of system breakdowns, repairs, calibration checks, and zero and span adjustments, the COMS must be in continuous operation and must complete a minimum of one cycle of sampling and analyzing for each successive 10 second period and one cycle of data recording for each successive 6-minute period.

(E) You must reduce all data from the COMS to 6-minute averages. Six-minute opacity averages must be calculated from 36 or more data points equally spaced over each 6-minute period. Data recorded during periods of system breakdowns, repairs, calibration checks, and zero and span adjustments must not be included in the data averages. An arithmetic or integrated average of all data may be used.

(iii) During each performance test conducted according to paragraph (o)(1) of this section, you must establish an opacity baseline level. The value of the opacity baseline level is determined by averaging all of the 6-minute average opacity values (reported to the nearest 0.1 percent opacity) from the COMS measurements recorded during each of the test run intervals conducted for the performance test, and then adding 2.5 percent opacity to your calculated average opacity value for all of the test runs. If your calculated average opacity value for all of the test runs is less than 5.0 percent, then the opacity baseline level is set at 5.0 percent.

(iv) You must evaluate the preceding 24-hour average opacity level measured by the COMS each boiler operating day excluding periods of affected source startup, shutdown, or malfunction. If the measured 24-hour average opacity emission level is greater than the baseline opacity level determined in paragraph (o)(2)(iii) of this section, you must initiate investigation of the relevant equipment and control systems within 24 hours of the first discovery of the high opacity incident and take the appropriate corrective action as soon as practicable to adjust control settings or repair equipment to reduce the measured 24-hour average opacity to a level below the baseline opacity level.

(v) You must record the opacity measurements, calculations performed, and any corrective actions taken. The record of corrective action taken must include the date and time during which the measured 24-hour average opacity was greater than baseline opacity level, and the date, time, and description of the corrective action.

(vi) If the measured 24-hour average opacity for your affected source remains at a level greater than the opacity baseline level after 7 days, then you must conduct a new PM performance test according to paragraph (o)(1) of this section and establish a new opacity baseline value according to paragraph (o)(2) of this section. This new performance test must be conducted within 60 days of the date that the

measured 24-hour average opacity was first determined to exceed the baseline opacity level unless a wavier is granted by the appropriate delegated permitting authority.

(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(c)(2) or (d) 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(c)(2) or (d) 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 daily average liquid-to-gas flow rate for the wet scrubber must be maintained at 90 percent of average ratio measured during all test run intervals for the performance test conducted according to paragraph (o)(1) of this section.

(ii) You must develop a site-specific monitoring plan that includes a description of the ESP predictive model used, the model input parameters, and the procedures and criteria for establishing monitoring parameter baseline levels indicative of compliance with the PM emissions limit. You must submit the site-specific monitoring plan for approval by the appropriate delegated permitting authority. For reference purposes in preparing the monitoring plan, see the OAQPS "Compliance Assurance Monitoring (CAM) Protocol for an Electrostatic Precipitator (ESP) Controlling Particulate Matter (PM) Emissions from a Coal-Fired Boiler." This document is available from the U.S. Environmental Protection Agency (U.S. EPA); Office of Air Quality Planning and 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 Continuous Emission Monitoring .

(iii) You must run the ESP predictive model using the applicable input data each boiler operating day and evaluate the model output for the preceding boiler operating day excluding periods of affected source startup, shutdown, or malfunction. If the values for one or more of the model parameters exceed the applicable baseline levels determined according to your approved site-specific monitoring plan, you must initiate investigation of the relevant equipment and control systems within 24 hours of the first discovery of a model parameter deviation and, take the appropriate corrective action as soon as practicable to adjust control settings or repair equipment to return the model output to within the applicable baseline levels.

(iv) You must record the ESP predictive model inputs and outputs and any corrective actions taken. The record of corrective action taken must include the date and time during which the model output values exceeded the applicable baseline levels, and the date, time, and description of the corrective action.

(v) If after 7 consecutive days a model parameter continues to exceed the applicable baseline level, then you must conduct a new PM performance test according to paragraph (o)(1) of this section. This new performance test must be conducted within 60 days of the date that the model parameter was first determined to exceed its baseline level unless a wavier is granted by the appropriate delegated permitting authority.

(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(c)(2) or (d) by using a bag leak detection system according to the requirements in paragraphs (o)(4)(i) through (v) of this section.

(i) Each bag leak detection system must meet the specifications and requirements in paragraphs (o)(4)(i)(A) through (H) of this section.

(A) The bag leak detection system must be certified by the manufacturer to be capable of detecting PM emissions at concentrations of 1 milligram per actual cubic meter (0.00044 grains per actual cubic foot) or less.

(B) The bag leak detection system sensor must provide output of relative PM loadings. The owner or operator must continuously record the output from the bag leak detection system using electronic or other means (*e.g.*, using a strip chart recorder or a data logger.)

(C) The bag leak detection system must be equipped with an alarm system that will react when the system detects an increase in relative particulate loading over the alarm set point established according to paragraph (o)(4)(i)(D) of this section, and the alarm must be located such that it can be noticed by the appropriate plant personnel.

(D) In the initial adjustment of the bag leak detection system, you must establish, at a minimum, the baseline output by adjusting the sensitivity (range) and the averaging period of the device, the alarm set points, and the alarm delay time.

(E) Following initial adjustment, you must not adjust the averaging period, alarm set point, or alarm delay time without approval from the appropriate delegated permitting authority except as provided in paragraph (d)(1)(vi) of this section.

(F) Once per quarter, you may adjust the sensitivity of the bag leak detection system to account for seasonal effects, including temperature and humidity, according to the procedures identified in the site-specific monitoring plan required by paragraph (o)(4)(ii) of this section.

(G) You must install the bag leak detection sensor downstream of the fabric filter and upstream of any wet scrubber.

(H) Where multiple detectors are required, the system's instrumentation and alarm may be shared among detectors.

(ii) You must develop and submit to the appropriate delegated permitting authority for approval a site-specific monitoring plan for each bag leak detection system. You must operate and maintain the bag leak detection system according to the site-specific monitoring plan at all times. Each monitoring plan must describe the items in paragraphs (o)(4)(ii)(A) through (F) of this section.

(A) Installation of the bag leak detection system;

(B) Initial and periodic adjustment of the bag leak detection system, including how the alarm set-point will be established;

(C) Operation of the bag leak detection system, including quality assurance procedures;

(D) How the bag leak detection system will be maintained, including a routine maintenance schedule and spare parts inventory list;

(E) How the bag leak detection system output will be recorded and stored; and

(F) Corrective action procedures as specified in paragraph (o)(4)(iii) of this section. In approving the site-specific monitoring plan, the appropriate delegated permitting authority may allow owners and operators more than 3 hours to alleviate a specific condition that causes an alarm if the owner or operator identifies in the monitoring plan this specific condition as one that could lead to an alarm, adequately explains why it is not feasible to

alleviate this condition within 3 hours of the time the alarm occurs, and demonstrates that the requested time will ensure alleviation of this condition as expeditiously as practicable.

(iii) For each bag leak detection system, you must initiate procedures to determine the cause of every alarm within 1 hour of the alarm. Except as provided in paragraph (o)(4)(ii)(F) of this section, you must alleviate the cause of the alarm within 3 hours of the alarm by taking whatever corrective action(s) are necessary. Corrective actions may include, but are not limited to the following:

(A) Inspecting the fabric filter for air leaks, torn or broken bags or filter media, or any other condition that may cause an increase in particulate emissions;

(B) Sealing off defective bags or filter media;

(C) Replacing defective bags or filter media or otherwise repairing the control device;

(D) Sealing off a defective fabric filter compartment;

(E) Cleaning the bag leak detection system probe or otherwise repairing the bag leak detection system; or

(F) Shutting down the process producing the particulate emissions.

(iv) You must maintain records of the information specified in paragraphs (o)(4)(iv)(A) through (C) of this section for each bag leak detection system.

(A) Records of the bag leak detection system output;

(B) Records of bag leak detection system adjustments, including the date and time of the adjustment, the initial bag leak detection system settings, and the final bag leak detection system settings; and

(C) The date and time of all bag leak detection system alarms, the time that procedures to determine the cause of the alarm were initiated, if procedures were initiated within 1 hour of the alarm, the cause of the alarm, an explanation of the actions taken, the date and time the cause of the alarm was alleviated, and if the alarm was alleviated within 3 hours of the alarm.

(v) If after any period of composed of 30 boiler operating days during which the alarm rate exceeds 5 percent of the process operating time (excluding control device or process startup, shutdown, and malfunction), then you must conduct a new PM performance test according to paragraph (o)(1) of this section. This new performance test must be conducted within 60 days of the date that the alarm rate was first determined to exceed 5 percent limit unless a wavier is granted by the appropriate delegated permitting authority.

(5) An owner or operator of a modified affected source electing to meet the emission limitations in § .42Da(d) shall determine the percent reduction in PM by using the emission rate for PM determined by the performance test conducted according to the requirements in paragraph (o)(1) of this section and the ash content on a mass basis of the fuel burned during each performance test run as determined by analysis of the fuel as fired.

(p) As an alternative to meeting the compliance provisions specified in paragraph (o) of this section, an owner or operator may elect to install, certify, maintain, and operate a CEMS measuring PM emissions discharged from the affected facility to the atmosphere and record the output of the system as specified in paragraphs (p)(1) through (p)(8) of this section.

(1) The owner or operator shall submit a written notification to the Administrator of intent to demonstrate compliance with this subpart by using a CEMS measuring PM. This notification shall be sent at least 30 calendar days before the initial startup of the monitor for compliance determination purposes. The owner or operator may discontinue operation of the monitor and instead return to demonstration of compliance with this subpart according to the requirements in paragraph (o) of this section by submitting written notification to the Administrator of such intent at least 30 calendar days before shutdown of the monitor for compliance determination purposes.

(2) Each CEMS shall be installed, certified, operated, and maintained according to the requirements in § 60.49Da(v).

(3) The initial performance evaluation shall be completed no later than 180 days after the date of initial startup of the affected facility, as specified under § 60.8 of subpart A of this part or within 180 days of the date of notification to the Administrator required under paragraph (p)(1) of this section, whichever is later.

(4) Compliance with the applicable emissions limit shall be determined based on the 24-hour daily (block) average of the hourly arithmetic average emissions concentrations using the continuous monitoring system outlet data. The 24-hour block arithmetic average emission concentration shall be calculated using EPA Reference Method 19 of appendix A of this part, section 4.1.

(5) At a minimum, valid CEMS hourly averages shall be obtained for 75 percent of all operating hours on a 30-day rolling average basis. Beginning on January 1, 2012, valid CEMS hourly averages shall be obtained for 90 percent of all operating hours on a 30-day rolling average basis.

(i) At least two data points per hour shall be used to calculate each 1-hour arithmetic average.

(ii) [Reserved]

(6) The 1-hour arithmetic averages required shall be expressed in ng/J, MMBtu/hr, or lb/MWh and shall be used to calculate the boiler operating day daily arithmetic average emission concentrations. The 1-hour arithmetic averages shall be calculated using the data points required under § 60.13(e)(2) of subpart A of this part.

(7) All valid CEMS data shall be used in calculating average emission concentrations even if the minimum CEMS data requirements of paragraph (j)(5) of this section are not met.

(8) When PM emissions data are not obtained because of CEMS breakdowns, repairs, calibration checks, and zero and span adjustments, emissions data shall be obtained by using other monitoring systems as approved by the Administrator or EPA Reference Method 19 of appendix A of this part to provide, as necessary, valid emissions data for a minimum of 90 percent (only 75 percent is required prior to January 1, 2012) of all operating hours per 30-day rolling average.

**§ 60.49Da Emission monitoring.**

(a) Except as provided for in paragraphs (t) and (u) of this section, the owner or operator of an affected facility, shall install, calibrate, maintain, and operate a CEMS, and record the output of the system, for measuring the opacity of emissions discharged to the atmosphere. If opacity interference due to water droplets exists in the stack (for example, from the use of an FGD system), the opacity is monitored upstream of the interference (at the inlet to the FGD system). If opacity interference is experienced at all locations (both at the inlet and outlet of the $SO_2$ control system), alternate parameters indicative of the PM control system's performance and/or good combustion are monitored (subject to the approval of the Administrator).

(b) The owner or operator of an affected facility shall install, calibrate, maintain, and operate a CEMS, and record the output of the system, for measuring $SO_2$ emissions, except where natural gas is the only fuel combusted, as follows:

(1) Sulfur dioxide emissions are monitored at both the inlet and outlet of the $SO_2$ control device.

(2) For a facility that qualifies under the numerical limit provisions of § 60.43Da(d), (i), (j), or (k) $SO_2$ emissions are only monitored as discharged to the atmosphere.

(3) An "as fired" fuel monitoring system (upstream of coal pulverizers) meeting the requirements of Method 19 of appendix A of this part may be used to determine potential $SO_2$ emissions in place of a continuous $SO_2$ emission monitor at the inlet to the $SO_2$ control device as required under paragraph (b)(1) of this section.

(4) If the owner or operator has installed and certified a $SO_2$ continuous emissions monitoring system (CEMS) according to the requirements of § 75.20(c)(1) of this chapter and appendix A to part 75 of this chapter, and is continuing to meet the ongoing quality assurance requirements of § 75.21 of this chapter and appendix B to part 75 of this chapter, that CEMS may be used to meet the requirements of this section, provided that:

(i) A $CO_2$ or $O_2$ continuous monitoring system is installed, calibrated, maintained and operated at the same location, according to paragraph (d) of this section; and

(ii) For sources subject to an $SO_2$ emission limit in lb/MMBtu under § 60.43Da:

(A) When relative accuracy testing is conducted, $SO_2$ concentration data and $CO_2$ (or $O_2$) data are collected simultaneously; and

(B) In addition to meeting the applicable $SO_2$ and $CO_2$ (or $O_2$) relative accuracy specifications in Figure 2 of appendix B to part 75 of this chapter, the relative accuracy (RA) standard in section 13.2 of Performance Specification 2 in appendix B to this part is met when the RA is calculated on a lb/MMBtu basis; and

(iii) The reporting requirements of § 60.51Da are met. The $SO_2$ and $CO_2$ (or $O_2$) data reported to meet the requirements of § 60.51Da shall not include substitute data values derived from the missing data procedures in subpart D of part 75 of this chapter, nor shall the $SO_2$ data have been bias adjusted according to the procedures of part 75 of this chapter.

(c)(1) The owner or operator of an affected facility shall install, calibrate, maintain, and operate a CEMS, and record the output of the system, for measuring $NO_X$ emissions discharged to the atmosphere; or

(2) If the owner or operator has installed a $NO_X$ emission rate CEMS to meet the requirements of part 75 of this chapter and is continuing to meet the ongoing requirements of part 75 of this chapter, that CEMS may be used to meet the requirements of this section, except that the owner or operator shall also meet the requirements of § 60.51Da. Data reported to meet the requirements of § 60.51Da shall not include data substituted using the missing data procedures in subpart D of part 75 of this chapter, nor shall the data have been bias adjusted according to the procedures of part 75 of this chapter.

(d) The owner or operator of an affected facility shall install, calibrate, maintain, and operate a CEMS, and record the output of the system, for measuring the $O_2$ or carbon dioxide ($CO_2$) content of the flue gases at each location where $SO_2$ or $NO_X$ emissions are monitored. For affected facilities subject to a lb/MMBtu $SO_2$ emission limit under § 60.43Da, if the owner or operator has installed and certified a $CO_2$ or $O_2$ monitoring system according to § 75.20(c) of this chapter and Appendix A to part 75 of this chapter and the monitoring system continues to meet the applicable quality-assurance provisions of § 75.21 of this chapter and appendix B to part 75 of this chapter, that CEMS may be used together with the part 75 $SO_2$ concentration monitoring system described in paragraph (b) of this section, to determine the $SO_2$ emission rate in lb/MMBtu. $SO_2$ data used to meet the requirements of § 60.51Da shall not include substitute data values derived from the missing data procedures in subpart D of part 75 of this chapter, nor shall the data have been bias adjusted according to the procedures of part 75 of this chapter.

(e) The CEMS under paragraphs (b), (c), and (d) of this section are operated and data recorded during all periods of operation of the affected facility including periods of startup, shutdown, malfunction or emergency conditions, except for CEMS breakdowns, repairs, calibration checks, and zero and span adjustments.

(f)(1) For units that began construction, reconstruction, or modification on or before February 28, 2005, the owner or operator shall obtain emission data for at least 18 hours in at least 22 out of 30 successive boiler operating days. If this minimum data requirement cannot be met with CEMS, the owner or operator shall supplement emission data with other monitoring systems approved by the Administrator or the reference methods and procedures as described in paragraph (h) of this section.

(2) For units that began construction, reconstruction, or modification after February 28, 2005, the owner or operator shall obtain emission data for at least 90 percent of all operating hours for each 30 successive boiler operating days. If this minimum data requirement cannot be met with a CEMS, the owner or operator shall supplement emission data with other monitoring systems approved by the Administrator or the reference methods and procedures as described in paragraph (h) of this section.

(g) The 1-hour averages required under paragraph § 60.13(h) are expressed in ng/J (lb/MMBtu) heat input and used to calculate the average emission rates under § 60.48Da. The 1-hour averages are calculated using the data points required under § 60.13(h)(2).

(h) When it becomes necessary to supplement CEMS data to meet the minimum data requirements in paragraph (f) of this section, the owner or operator shall use the reference methods and procedures as specified in this paragraph. Acceptable alternative methods and procedures are given in paragraph (j) of this section.

(1) Method 6 of appendix A of this part shall be used to determine the $SO_2$ concentration at the same location as the $SO_2$ monitor. Samples shall be taken at 60-minute intervals. The sampling time and sample volume for each sample shall be at least 20 minutes and 0.020 dscm (0.71 dscf). Each sample represents a 1-hour average.

(2) Method 7 of appendix A of this part shall be used to determine the $NO_X$ concentration at the same location as the $NO_X$ monitor. Samples shall be taken at 30-minute intervals. The arithmetic average of two consecutive samples represents a 1-hour average.

(3) The emission rate correction factor, integrated bag sampling and analysis procedure of Method 3B of appendix A of this part shall be used to determine the $O_2$ or $CO_2$ concentration at the same location as the $O_2$ or $CO_2$ monitor. Samples shall be taken for at least 30 minutes in each hour. Each sample represents a 1-hour average.

(4) The procedures in Method 19 of appendix A of this part shall be used to compute each 1-hour average concentration in ng/J (lb/MMBtu) heat input.

(i) The owner or operator shall use methods and procedures in this paragraph to conduct monitoring system performance evaluations under § 60.13(c) and calibration checks under § 60.13(d). Acceptable alternative methods and procedures are given in paragraph (j) of this section.

(1) Methods 3B, 6, and 7 of appendix A of this part shall be used to determine $O_2$, $SO_2$, and $NO_X$ concentrations, respectively.

(2) $SO_2$ or $NO_X$ (NO), as applicable, shall be used for preparing the

calibration gas mixtures (in $N_2$, as applicable) under Performance Specification 2 of appendix B of this part.

(3) For affected facilities burning only fossil fuel, the span value for a CEMS for measuring opacity is between 60 and 80 percent. Span values for a CEMS measuring $NO_X$ shall be determined using one of the following procedures:

(i) Except as provided under paragraph (i)(3)(ii) of this section, $NO_X$ span values shall be determined as follows:

| Fossil fuel | Span values for $NO_X$ (ppm) |
|---|---|
| Gas | 500. |
| Liquid | 500. |
| Solid | 1,000. |
| Combination | 500 (x + y) + 1,000z. |

Where:

x = Fraction of total heat input derived from gaseous fossil fuel,

y = Fraction of total heat input derived from liquid fossil fuel, and

z = Fraction of total heat input derived from solid fossil fuel.

(ii) As an alternative to meeting the requirements of paragraph (i)(3)(i) of this section, the owner or operator of an affected facility may elect to use the $NO_X$ span values determined according to section 2.1.2 in appendix A to part 75 of this chapter.

(4) All span values computed under paragraph (i)(3)(i) of this section for burning combinations of fossil fuels are rounded to the nearest 500 ppm. Span values computed under paragraph (i)(3)(ii) of this section shall be rounded off according to section 2.1.2 in appendix A to part 75 of this chapter.

(5) For affected facilities burning fossil fuel, alone or in combination with non-fossil fuel and determining span values under paragraph (i)(3)(i) of this section, the span value of the $SO_2$ CEMS at the inlet to the $SO_2$ control device is 125 percent of the maximum estimated hourly potential emissions of the fuel fired, and the outlet of the $SO_2$ control device is 50 percent of maximum estimated hourly potential emissions of the fuel fired. For affected facilities determining span values under paragraph (i)(3)(ii) of this section, $SO_2$ span values shall be determined according to section 2.1.1 in appendix A to part 75 of this chapter.

(j) The owner or operator may use the following as alternatives to the reference methods and procedures specified in this section:

(1) For Method 6 of appendix A of this part, Method 6A or 6B (whenever Methods 6 and 3 or 3B of appendix A of this part data are used) or 6C of appendix A of this part may be used. Each Method 6B of appendix A of this part sample obtained over 24 hours represents 24 1-hour averages. If Method 6A or 6B of appendix A of this part is used under paragraph (i) of this section, the conditions under § 60.48Da(d)(1) apply; these conditions do not apply under paragraph (h) of this section.

(2) For Method 7 of appendix A of this part, Method 7A, 7C, 7D, or 7E of appendix A of this part may be used. If Method 7C, 7D, or 7E of appendix A of this part is used, the sampling time for each run shall be 1 hour.

(3) For Method 3 of appendix A of this part, Method 3A or 3B of appendix A of this part may be used if the sampling time is 1 hour.

(4) For Method 3B of appendix A of this part, Method 3A of appendix A of this part may be used.

(k) The procedures specified in paragraphs (k)(1) through (3) of this section shall be used to determine gross output for sources demonstrating compliance with the output-based standard under § 60.44Da(d)(1).

(1) The owner or operator of an affected facility with electricity generation shall install, calibrate, maintain, and operate a wattmeter; measure gross electrical output in MWh on a continuous basis; and record the output of the monitor.

(2) The owner or operator of an affected facility with process steam generation shall install, calibrate, maintain, and operate meters for steam flow, temperature, and pressure; measure gross process steam output in joules per hour (or Btu per hour) on a continuous basis; and record the output of the monitor.

(3) For affected facilities generating process steam in combination with electrical generation, the gross energy output is determined from the gross electrical output measured in accordance with paragraph (k)(1) of this section plus 75 percent of the gross thermal output (measured relative to ISO conditions) of the process steam measured in accordance with paragraph (k)(2) of this section.

(l) The owner or operator of an affected facility demonstrating compliance with an output-based standard under § 60.42Da, § 60,43Da, § 60.44Da, or § 60.45Da shall install, certify, operate, and maintain a continuous flow monitoring system meeting the requirements of Performance Specification 6 of appendix B of this part and the CD assessment, RATA and reporting provisions of procedure 1 of appendix F of this part, and record the output of the system, for measuring the volumetric flow rate of exhaust gases discharged to the atmosphere; or

(m) Alternatively, data from a continuous flow monitoring system certified according to the requirements of § 75.20(c) of this chapter and appendix A to part 75 of this chapter, and continuing to meet the applicable quality control and quality assurance requirements of § 75.21 of this chapter and appendix B to part 75 of this chapter, may be used. Flow rate data reported to meet the requirements of § 60.51Da shall not include substitute data values derived from the missing data procedures in subpart D of part 75 of this chapter, nor shall the data have been bias adjusted according to the procedures of part 75 of this chapter.

(n) Gas-fired and oil-fired units. The owner or operator of an affected unit that qualifies as a gas-fired or oil-fired unit, as defined in 40 CFR 72.2, may use, as an alternative to the requirements specified in either paragraph (l) or (m) of this section, a fuel flow monitoring system certified and operated according to the requirements of appendix D of part 75 of this chapter.

(o) The owner or operator of a duct burner, as described in § 60.41Da, which is subject to the $NO_X$ standards of § 60.44Da(a)(1), (d)(1), or (e)(1) is not required to install or operate a CEMS to measure $NO_X$ emissions; a wattmeter to measure gross electrical output; meters to measure steam flow, temperature, and pressure; and a continuous flow monitoring system to measure the flow of exhaust gases discharged to the atmosphere.

(p) The owner or operator of an affected facility demonstrating compliance with an Hg limit in § 60.45Da shall install and operate a CEMS to measure and record the concentration of Hg in the exhaust gases from each stack according to the requirements in paragraphs (p)(1) through (p)(3) of this section. Alternatively, for an affected facility that is also subject to the requirements of subpart I of part 75 of this chapter, the owner or operator may install, certify, maintain, operate and quality-assure the data from a Hg CEMS according to § 75.10 of this chapter and appendices A and B to part 75 of this chapter, in lieu of following the procedures in paragraphs (p)(1) through (p)(3) of this section.

(1) The owner or operator must install, operate, and maintain each CEMS according to Performance Specification 12A in appendix B to this part.

(2) The owner or operator must conduct a performance evaluation of

each CEMS according to the requirements of § 60.13 and Performance Specification 12A in appendix B to this part.

(3) The owner or operator must operate each CEMS according to the requirements in paragraphs (p)(3)(i) through (iv) of this section.

(i) As specified in § 60.13(e)(2), each CEMS must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period.

(ii) The owner or operator must reduce CEMS data as specified in § 60.13(h).

(iii) The owner or operator shall use all valid data points collected during the hour to calculate the hourly average Hg concentration.

(iv) The owner or operator must record the results of each required certification and quality assurance test of the CEMS.

(4) Mercury CEMS data collection must conform to paragraphs (p)(4)(i) through (iv) of this section.

(i) For each calendar month in which the affected unit operates, valid hourly Hg concentration data, stack gas volumetric flow rate data, moisture data (if required), and electrical output data (i.e., valid data for all of these parameters) shall be obtained for at least 75 percent of the unit operating hours in the month.

(ii) Data reported to meet the requirements of this subpart shall not include hours of unit startup, shutdown, or malfunction. In addition, for an affected facility that is also subject to subpart I of part 75 of this chapter, data reported to meet the requirements of this subpart shall not include data substituted using the missing data procedures in subpart D of part 75 of this chapter, nor shall the data have been bias adjusted according to the procedures of part 75 of this chapter.

(iii) If valid data are obtained for less than 75 percent of the unit operating hours in a month, you must discard the data collected in that month and replace the data with the mean of the individual monthly emission rate values determined in the last 12 months. In the 12-month rolling average calculation, this substitute Hg emission rate shall be weighted according to the number of unit operating hours in the month for which the data capture requirement of § 60.49Da(p)(4)(i) was not met.

(iv) Notwithstanding the requirements of paragraph (p)(4)(iii) of this section, if valid data are obtained for less than 75 percent of the unit operating hours in another month in that same 12-month rolling average cycle, discard the data collected in that month and replace the data with the highest individual monthly emission rate determined in the last 12 months. In the 12-month rolling average calculation, this substitute Hg emission rate shall be weighted according to the number of unit operating hours in the month for which the data capture requirement of § 60.49Da(p)(4)(i) was not met.

(q) As an alternative to the CEMS required in paragraph (p) of this section, the owner or operator may use a sorbent trap monitoring system (as defined in § 72.2 of this chapter) to monitor Hg concentration, according to the procedures described in § 75.15 of this chapter and appendix K to part 75 of this chapter.

(r) For Hg CEMS that measure Hg concentration on a dry basis or for sorbent trap monitoring systems, the emissions data must be corrected for the stack gas moisture content. A certified continuous moisture monitoring system that meets the requirements of § 75.11(b) of this chapter is acceptable for this purpose. Alternatively, the appropriate default moisture value, as specified in § 75.11(b) or § 75.12(b) of this chapter, may be used.

(s) The owner or operator shall prepare and submit to the Administrator for approval a unit-specific monitoring plan for each monitoring system, at least 45 days before commencing certification testing of the monitoring systems. The owner or operator shall comply with the requirements in your plan. The plan must address the requirements in paragraphs (s)(1) through (6) of this section.

(1) Installation of the CEMS sampling probe or other interface at a measurement location relative to each affected process unit such that the measurement is representative of the exhaust emissions (*e.g.*, on or downstream of the last control device);

(2) Performance and equipment specifications for the sample interface, the pollutant concentration or parametric signal analyzer, and the data collection and reduction systems;

(3) Performance evaluation procedures and acceptance criteria (*e.g.*, calibrations, relative accuracy test audits (RATA), etc.);

(4) Ongoing operation and maintenance procedures in accordance with the general requirements of § 60.13(d) or part 75 of this chapter (as applicable);

(5) Ongoing data quality assurance procedures in accordance with the general requirements of § 60.13 or part 75 of this chapter (as applicable); and

(6) Ongoing recordkeeping and reporting procedures in accordance with the requirements of this subpart.

(t) The owner or operator of an affected facility demonstrating compliance with the output-based emissions limitation under § 60.42Da(c)(1) shall install, certify, operate, and maintain a CEMS for measuring PM emissions according to the requirements of paragraph (v) of this section. An owner or operator of an affected source demonstrating compliance with the input-based emission limitation under § 60.42Da(c)(2) may install, certify, operate, and maintain a CEMS for measuring PM emissions according to the requirements of paragraph (v) of this section.

(u) An owner or operator of an affected source that meets the conditions in either paragraph (u)(1), (2) or (3) of this section is exempted from the continuous opacity monitoring system requirements in paragraph (a) of this section and the monitoring requirements in § 60.48Da(o).

(1) A CEMS for measuring PM emissions is used to demonstrate continuous compliance on a boiler operating day average with the emissions limitations under § 60.42Da(a)(1) or § 60.42Da(c)(2) and is installed, certified, operated, and maintained on the affected source according to the requirements of paragraph (v) of this section; or

(2) The affected source burns only gaseous fuels and does not use a post-combustion technology to reduce emissions of $SO_2$ or PM; or

(3) The affected source does not use post-combustion technology (except a wet scrubber) for reducing PM, $SO_2$, or carbon monoxide (CO) emissions, burns only natural gas, gaseous fuels, or fuel oils that contain less than or equal to 0.30 weight percent sulfur, and is operated such that emissions of CO to the atmosphere from the affected source are maintained at levels less than or equal to 1.4 lb/MWh on a boiler operating day average basis. Owners and operators of affected sources electing to comply with this paragraph must demonstrate compliance according to the procedures specified in paragraphs (u)(3)(i) through (iv) of this section.

(i) You must monitor CO emissions using a CEMS according to the procedures specified in paragraphs (u)(3)(i)(A) through (D) of this section.

(A) The CO CEMS must be installed, certified, maintained, and operated according to the provisions in § 60.58b(i)(3) of subpart Eb of this part.

(B) Each 1-hour CO emissions average is calculated using the data points generated by the CO CEMS expressed in parts per million by volume corrected to 3 percent oxygen (dry basis).

(C) At a minimum, valid 1-hour CO emissions averages must be obtained for at least 90 percent of the operating hours on a 30-day rolling average basis. At least two data points per hour must be used to calculate each 1-hour average.

(D) Quarterly accuracy determinations and daily calibration drift tests for the CO CEMS must be performed in accordance with procedure 1 in appendix F of this part.

(ii) You must calculate the 1-hour average CO emissions levels for each boiler operating day by multiplying the average hourly CO output concentration measured by the CO CEMS times the corresponding average hourly flue gas flow rate and divided by the corresponding average hourly useful energy output from the affected source. The 24-hour average CO emission level is determined by calculating the arithmetic average of the hourly CO emission levels computed for each boiler operating day.

(iii) You must evaluate the preceding 24-hour average CO emission level each boiler operating day excluding periods of affected source startup, shutdown, or malfunction. If the 24-hour average CO emission level is greater than 1.4 lb/MWh, you must initiate investigation of the relevant equipment and control systems within 24 hours of the first discovery of the high emission incident and, take the appropriate corrective action as soon as practicable to adjust control settings or repair equipment to reduce the 24-hour average CO emission level to 1.4 lb/MWh or less.

(iv) You must record the CO measurements and calculations performed according to paragraph (u)(3) of this section and any corrective actions taken. The record of corrective action taken must include the date and time during which the 24-hour average CO emission level was greater than 1.4 lb/MWh, and the date, time, and description of the corrective action.

(v) The owner or operator of an affected facility using a CEMS measuring PM emissions to meet requirements of this subpart shall install, certify, operate, and maintain the CEMS as specified in paragraphs (v)(1) through (v)(3).

(1) The owner or operator shall conduct a performance evaluation of the CEMS according to the applicable requirements of § 60.13, Performance Specification 11 in appendix B of this part, and procedure 2 in appendix F of this part.

(2) During each relative accuracy test run of the CEMS required by Performance Specification 11 in appendix B of this part, PM and $O_2$ (or $CO_2$) data shall be collected concurrently (or within a 30-to 60-minute period) by both the CEMS and conducting performance tests using the following test methods.

(i) For PM, EPA Reference Method 5, 5B, or 17 of appendix A of this part shall be used.

(ii) For $O_2$ (or $CO_2$), EPA Reference Method 3, 3A, or 3B of appendix A of this part, as applicable shall be used.

(3) Quarterly accuracy determinations and daily calibration drift tests shall be performed in accordance with procedure 2 in appendix F of this part. Relative Response Audit's must be performed annually and Response Correlation Audits must be performed every 3 years.

(w)(1) Except as provided for under paragraphs (w)(2), (w)(3), and (w)(4) of this section, the $SO_2$, $NO_X$, $CO_2$, and $O_2$ CEMS required under paragraphs (b) through (d) of this section shall be installed, certified, and operated in accordance with the applicable procedures in Performance Specification 2 or 3 in appendix B to this part or according to the procedures in appendices A and B to part 75 of this chapter. Daily calibration drift assessments and quarterly accuracy determinations shall be done in accordance with Procedure 1 in appendix F to this part, and a data assessment report (DAR), prepared according to section 7 of Procedure 1 in appendix F to this part, shall be submitted with each compliance report required under § 60.51Da., the owner or operator may elect to implement the following alternative data accuracy assessment procedures:

(2) As an alternative to meeting the requirements of paragraph (w)(1) of this section, an owner or operator may elect to may elect to implement the following alternative data accuracy assessment procedures. For all required $CO_2$ and $O_2$ CEMS and for $SO_2$ and $NO_X$ CEMS with span values greater than 100 ppm, the daily calibration error test and calibration adjustment procedures described in sections 2.1.1 and 2.1.3 of appendix B to part 75 of this chapter may be followed instead of the CD assessment procedures in Procedure 1, section 4.1 of appendix F of this part. If this option is selected, the data validation and out-of-control provisions in sections 2.1.4 and 2.1.5 of appendix B to part 75 of this chapter shall be followed instead of the excessive CD and out-of-control criteria in Procedure 1, section 4.3 of appendix F to this part. For the purposes of data validation under this subpart, the excessive CD and out-of-control criteria in Procedure 1, section 4.3 of appendix F to this part shall apply to $SO_2$ and $NO_X$ span values less than 100 ppm;

(3) As an alternative to meeting the requirements of paragraph (w)(1) of this section, an owner or operator may elect to may elect to implement the following alternative data accuracy assessment procedures. For all required $CO_2$ and $O_2$ CEMS and for $SO_2$ and $NO_X$ CEMS with span values greater than 30 ppm, quarterly linearity checks may be performed in accordance with section 2.2.1 of appendix B to part 75 of this chapter, instead of performing the cylinder gas audits (CGAs) described in Procedure 1, section 5.1.2 of appendix F to this part. If this option is selected: The frequency of the linearity checks shall be as specified in section 2.2.1 of appendix B to part 75 of this chapter; the applicable linearity specifications in section 3.2 of appendix A to part 75 of this chapter shall be met; the data validation and out-of-control criteria in section 2.2.3 of appendix B to part 75 of this chapter shall be followed instead of the excessive audit inaccuracy and out-of-control criteria in Procedure 1, section 5.2 of appendix F to this part; and the grace period provisions in section 2.2.4 of appendix B to part 75 of this chapter shall apply. For the purposes of data validation under this subpart, the cylinder gas audits described in Procedure 1, section 5.1.2 of appendix F to this part shall be performed for $SO_2$ and $NO_X$ span values less than or equal to 30 ppm;

(4) As an alternative to meeting the requirements of paragraph (w)(1) of this section, an owner or operator may elect to may elect to implement the following alternative data accuracy assessment procedures. For $SO_2$, $CO_2$, and $O_2$ CEMS and for $NO_X$ CEMS, RATAs may be performed in accordance with section 2.3 of appendix B to part 75 of this chapter instead of following the procedures described in Procedure 1, section 5.1.1 of appendix F to this part. If this option is selected: The frequency of each RATA shall be as specified in section 2.3.1 of appendix B to part 75 of this chapter; the applicable relative accuracy specifications shown in Figure 2 in appendix B to part 75 of this chapter shall be met; the data validation and out-of-control criteria in section 2.3.2 of appendix B to part 75 of this chapter shall be followed instead of the excessive audit inaccuracy and out-of-control criteria in Procedure 1, section 5.2 of appendix F to this part; and the grace period provisions in section 2.3.3 of appendix B to part 75 of this chapter shall apply. For the purposes of data validation under this subpart, the relative accuracy specification in section 13.2 of Performance

Specification 2 in appendix B to this part shall be met on a lb/MMBtu basis for $SO_2$ (regardless of the $SO_2$ emission level during the RATA), and for $NO_X$ when the average $NO_X$ emission rate measured by the reference method during the RATA is less than 0.100 lb/MMBtu;

(5) If the owner or operator elects to implement the alternative data assessment procedures described in paragraphs (w)(2) through (w)(4) of this section, each data assessment report shall include a summary of the results of all of the RATAs, linearity checks, CGAs, and calibration error or drift assessments required by paragraphs (w)(2) through (w)(4) of this section.

**§ 60.50Da Compliance determination procedures and methods.**

(a) In conducting the performance tests required in § 60.8, the owner or operator shall use as reference methods and procedures the methods in appendix A of this part or the methods and procedures as specified in this section, except as provided in § 60.8(b). Section 60.8(f) does not apply to this section for $SO_2$ and $NO_X$. Acceptable alternative methods are given in paragraph (e) of this section.

(b) The owner or operator shall determine compliance with the PM standards in § 60.42Da as follows:

(1) The dry basis F factor ($O_2$) procedures in Method 19 of appendix A of this part shall be used to compute the emission rate of PM.

(2) For the particular matter concentration, Method 5 of appendix A of this part shall be used at affected facilities without wet FGD systems and Method 5B of appendix A of this part shall be used after wet FGD systems.

(i) The sampling time and sample volume for each run shall be at least 120 minutes and 1.70 dscm (60 dscf). The probe and filter holder heating system in the sampling train may be set to provide an average gas temperature of no greater than 160±14 °C (320±25 °F).

(ii) For each particulate run, the emission rate correction factor, integrated or grab sampling and analysis procedures of Method 3B of appendix A of this part shall be used to determine the $O_2$ concentration. The $O_2$ sample shall be obtained simultaneously with, and at the same traverse points as, the particulate run. If the particulate run has more than 12 traverse points, the $O_2$ traverse points may be reduced to 12 provided that Method 1 of appendix A of this part is used to locate the 12 $O_2$ traverse points. If the grab sampling procedure is used, the $O_2$ concentration for the run shall be the arithmetic mean of the sample $O_2$ concentrations at all traverse points.

(3) Method 9 of appendix A of this part and the procedures in § 60.11 shall be used to determine opacity.

(c) The owner or operator shall determine compliance with the $SO_2$ standards in § 60.43Da as follows:

(1) The percent of potential $SO_2$ emissions (%Ps) to the atmosphere shall be computed using the following equation:

$$\%P_s = \frac{(100 - \%R_f)(100 - \%R_g)}{100}$$

Where:

%Ps = Percent of potential $SO_2$ emissions, percent;

%Rf = Percent reduction from fuel pretreatment, percent; and

%Rg = Percent reduction by $SO_2$ control system, percent.

(2) The procedures in Method 19 of appendix A of this part may be used to determine percent reduction ($\%R_f$) of sulfur by such processes as fuel pretreatment (physical coal cleaning, hydrodesulfurization of fuel oil, etc.), coal pulverizers, and bottom and fly ash interactions. This determination is optional.

(3) The procedures in Method 19 of appendix A of this part shall be used to determine the percent $SO_2$ reduction ($\%R_g$) of any $SO_2$ control system. Alternatively, a combination of an "as fired" fuel monitor and emission rates measured after the control system, following the procedures in Method 19 of appendix A of this part, may be used if the percent reduction is calculated using the average emission rate from the $SO_2$ control device and the average $SO_2$ input rate from the "as fired" fuel analysis for 30 successive boiler operating days.

(4) The appropriate procedures in Method 19 of appendix A of this part shall be used to determine the emission rate.

(5) The CEMS in § 60.49Da(b) and (d) shall be used to determine the concentrations of $SO_2$ and $CO_2$ or $O_2$.

(d) The owner or operator shall determine compliance with the $NO_X$ standard in § 60.44Da as follows:

(1) The appropriate procedures in Method 19 of appendix A of this part shall be used to determine the emission rate of $NO_X$.

(2) The continuous monitoring system in § 60.49Da(c) and (d) shall be used to determine the concentrations of $NO_X$ and $CO_2$ or $O_2$.

(e) The owner or operator may use the following as alternatives to the reference methods and procedures specified in this section:

(1) For Method 5 or 5B of appendix A of this part, Method 17 of appendix A of this part may be used at facilities with or without wet FGD systems if the stack temperature at the sampling location does not exceed an average temperature of 160 °C (320 °F). The procedures of §§ 2.1 and 2.3 of Method 5B of appendix A of this part may be used in Method 17 of appendix A of this part only if it is used after wet FGD systems. Method 17 of appendix A of this part shall not be used after wet FGD systems if the effluent is saturated or laden with water droplets.

(2) The $F_c$ factor ($CO_2$) procedures in Method 19 of appendix A of this part may be used to compute the emission rate of PM under the stipulations of § 60.46(d)(1). The $CO_2$ shall be determined in the same manner as the $O_2$ concentration.

(f) Electric utility combined cycle gas turbines are performance tested for PM, $SO_2$, and $NO_X$ using the procedures of Method 19 of appendix A of this part. The $SO_2$ and $NO_X$ emission rates from the gas turbine used in Method 19 of appendix A of this part calculations 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.

(g) For the purposes of determining compliance with the emission limits in § 60.45Da, the owner or operator of an electric utility steam generating unit which is also a cogeneration unit shall use the procedures in paragraphs (g)(1) and (2) of this section to calculate emission rates based on electrical output to the grid plus 75 percent of the equivalent electrical energy (measured relative to ISO conditions) in the unit's process stream.

(1) All conversions from Btu/hr unit input to MW unit output must use equivalents found in 40 CFR 60.40(a)(1) for electric utilities (*i.e.*, 250 MMBtu/hr input to an electric utility steam generating unit is equivalent to 73 MW input to the electric utility steam generating unit); 73 MW input to the electric utility steam generating unit is equivalent to 25 MW output from the boiler electric utility steam generating unit; therefore, 250 MMBtu input to the electric utility steam generating unit is equivalent to 25 MW output from the electric utility steam generating unit).

(2) Use the Equation 5 in this section to determine the cogeneration Hg emission rate over a specific compliance period.

$$ER_{cogen} = \frac{M}{\left(V_{grid} + 0.75 \times V_{process}\right)} \qquad \text{(Eq. 5)}$$

Where:

$ER_{cogen}$ = Cogeneration Hg emission rate over a compliance period in lb/MWh;

E = Mass of Hg emitted from the stack over the same compliance period (lb);

$V_{grid}$ = Amount of energy sent to the grid over the same compliance period (MWh); and

$V_{process}$ = Amount of energy converted to steam for process use over the same compliance period (MWh).

(h) The owner or operator shall determine compliance with the Hg limit in § 60.45Da according to the procedures in paragraphs (h)(1) through (3) of this section.

(1) The initial performance test shall be commenced by the applicable date specified in § 60.8(a). The required CEMS must be certified prior to commencing the test. The performance test consists of collecting hourly Hg emission data (lb/MWh) with the CEMS for 12 successive months of unit operation (excluding hours of unit startup, shutdown and malfunction). The average Hg emission rate is calculated for each month, and then the weighted, 12-month average Hg emission rate is calculated according to paragraph (h)(2) or (h)(3) of this section, as applicable. If, for any month in the initial performance test, the minimum data capture requirement in § 60.49Da(p)(4)(i) is not met, the owner or operator shall report a substitute Hg emission rate for that month, as follows. For the first such month, the substitute monthly Hg emission rate shall be the arithmetic average of all valid hourly Hg emission rates recorded to date. For any subsequent month(s) with insufficient data capture, the substitute monthly Hg emission rate shall be the highest valid hourly Hg emission rate recorded to date. When the 12-month average Hg emission rate for the initial performance test is calculated, for each month in which there was insufficient data capture, the substitute monthly Hg emission rate shall be weighted according to the number of unit operating hours in that month. Following the initial performance test, the owner or operator shall demonstrate compliance by calculating the weighted average of all monthly Hg emission rates (in lb/MWh) for each 12 successive calendar months, excluding data obtained during startup, shutdown, or malfunction.

(2) If a CEMS is used to demonstrate compliance, follow the procedures in paragraphs (h)(2)(i) through (iii) of this section to determine the 12-month rolling average.

(i) Calculate the total mass of Hg emissions over a month (M), in lb, using either Equation 6 in paragraph (h)(2)(i)(A) of this section or Equation 7 in paragraph (h)(2)(i)(B) of this section, in conjunction with Equation 8 in paragraph (h)(2)(i)(C) of this section.

(A) If the Hg CEMS measures Hg concentration on a wet basis, use Equation 6 below to calculate the Hg mass emissions for each valid hour:

$$E_h = KC_h\ Q_h\ t_h \qquad \text{(Eq. 6)}$$

Where:

$E_h$ = Hg mass emissions for the hour, (lb);

K = Units conversion constant, $6.24 \times 10^{-11}$ lb-scm/μgm-scf;

$C_h$ = Hourly $H_g$ concentration, wet basis, (μgm/scm);

$Q_h$ = Hourly stack gas volumetric flow rate, (scfh); and

$t_h$ = Unit operating time, i.e., the fraction of the hour for which the unit operated. For example, th = 0.50 for a half-hour of unit operation and 1.00 for a full hour of operation.

(B) If the Hg CEMS measures Hg concentration on a dry basis, use Equation 7 below to calculate the Hg mass emissions for each valid hour:

$$E_h = KC_h\ Q_h\ t_h\ \left(1 - B_{ws}\right) \qquad \text{(Eq. 7)}$$

Where:

$E_h$ = Hg mass emissions for the hour, (lb);

K = Units conversion constant, $6.24 \times 10^{-11}$ lb-scm/μgm-scf;

$C_h$ = Hourly Hg concentration, dry basis, (μgm/dscm);

$Q_h$ = Hourly stack gas volumetric flow rate, (scfh);

$t_h$ = Unit operating time, *i.e.*, the fraction of the hour for which the unit operated; and

$B_{ws}$ = Stack gas moisture content, expressed as a decimal fraction (*e.g.*, for 8 percent $H_2O$, $B_{ws} = 0.08$).

(C) Use Equation 8, below, to calculate M, the total mass of Hg emitted for the month, by summing the hourly masses derived from Equation 6 or 7 (as applicable):

$$M = \sum_{h=1}^{n} E_h \qquad \text{(Eq. 8)}$$

M = Total Hg mass emissions for the month, (lb);

$E_h$ = Hg mass emissions for hour "h", from Equation 6 or 7 of this section, (lb); and

n = Number of unit operating hours in the month with valid CE and electrical output data, excluding hours of unit startup, shutdown and malfunction.

(ii) Calculate the monthly Hg emission rate on an output basis (lb/MWh) using Equation 9, below. For a cogeneration unit, use Equation 5 in paragraph (g) of this section instead.

$$ER = \frac{M}{P} \qquad \text{(Eq. 9)}$$

Where:

ER = Monthly Hg emission rate, (lb/MWh);

M = Total mass of Hg emissions for the month, from Equation 8, above, (lb); and

P = Total electrical output for the month, for the hours used to calculate M, (MWh).

(iii) Until 12 monthly Hg emission rates have been accumulated, calculate and report only the monthly averages. Then, for each subsequent calendar month, use Equation 10 below to calculate the 12-month rolling average as a weighted average of the Hg emission rate for the current month and the Hg emission rates for the previous 11 months, with one exception. Calendar months in which the unit does not operate (zero unit operating hours) shall not be included in the 12-month rolling average.

$$E_{avg} = \frac{\sum_{i=1}^{12}\left(ER_i \times n_i\right)}{\sum_{i=1}^{12} n_i} \qquad \text{(Eq. 10)}$$

Where:

$E_{avg}$ = Weighted 12-month rolling average Hg emission rate, (lb/MWh);

$ER_i$ = Monthly Hg emission rate, for month "i", (lb/MWh); and

n = Number of unit operating hours in month "i" with valid CEM and electrical output data, excluding hours of unit startup, shutdown, and malfunction.

(3) If a sorbent trap monitoring system is used in lieu of a Hg CEMS, as described in § 75.15 of this chapter and in appendix K to part 75 of this chapter, calculate the monthly Hg emission rates using Equations 7 through 9 of this section, except that for a particular pair of sorbent traps, $C_h$ in Equation 7 shall be the flow-proportional average Hg concentration measured over the data collection period.

(i) Daily calibration drift (CD) tests and quarterly accuracy determinations shall be performed for Hg CEMS in accordance with Procedure 1 of appendix F to this part. For the CD assessments, you may use either elemental mercury or mercuric chloride ($Hg^{\circ}$ $HgCl_2$) standards. The four

quarterly accuracy determinations shall consist of one RATA and three measurement error (ME) tests using $HgCl_2$ standards, as described in section 8.3 of Performance Specification 12–A in appendix B to this part (note: $Hg^0$ standards may be used if the Hg monitor does not have a converter). Alternatively, the owner or operator may implement the applicable daily, weekly, quarterly, and annual quality assurance (QA) requirements for Hg CEMS in appendix B to part 75 of this chapter, in lieu of the QA procedures in appendices B and F to this part. Annual RATA of sorbent trap monitoring systems shall be performed in accordance with appendices A and B to part 75 of this chapter, and all other quality assurance requirements specified in appendix K to part 75 of this chapter shall be met for sorbent trap monitoring systems.

**§ 60.51Da Reporting requirements.**

(a) For $SO_2$, $NO_X$, PM, and Hg emissions, the performance test data from the initial and subsequent performance test and from the performance evaluation of the continuous monitors (including the transmissometer) are submitted to the Administrator.

(b) For $SO_2$ and $NO_X$ the following information is reported to the Administrator for each 24-hour period.

(1) Calendar date.

(2) The average $SO_2$ and $NO_X$ emission rates (ng/J or lb/MMBtu) for each 30 successive boiler operating days, ending with the last 30-day period in the quarter; reasons for non-compliance with the emission standards; and, description of corrective actions taken.

(3) Percent reduction of the potential combustion concentration of $SO_2$ for each 30 successive boiler operating days, ending with the last 30-day period in the quarter; reasons for non-compliance with the standard; and, description of corrective actions taken.

(4) Identification of the boiler operating days for which pollutant or diluent data have not been obtained by an approved method for at least 75 percent of the hours of operation of the facility; justification for not obtaining sufficient data; and description of corrective actions taken.

(5) Identification of the times when emissions data have been excluded from the calculation of average emission rates because of startup, shutdown, malfunction ($NO_X$ only), emergency conditions ($SO_2$ only), or other reasons, and justification for excluding data for reasons other than startup, shutdown, malfunction, or emergency conditions.

(6) Identification of "F" factor used for calculations, method of determination, and type of fuel combusted.

(7) Identification of times when hourly averages have been obtained based on manual sampling methods.

(8) Identification of the times when the pollutant concentration exceeded full span of the CEMS.

(9) Description of any modifications to CEMS which could affect the ability of the CEMS to comply with Performance Specifications 2 or 3.

(c) If the minimum quantity of emission data as required by § 60.49Da is not obtained for any 30 successive boiler operating days, the following information obtained under the requirements of § 60.48Da(h) is reported to the Administrator for that 30-day period:

(1) The number of hourly averages available for outlet emission rates (no) and inlet emission rates ($n_i$) as applicable.

(2) The standard deviation of hourly averages for outlet emission rates ($s_o$) and inlet emission rates ($s_i$) as applicable.

(3) The lower confidence limit for the mean outlet emission rate ($E_o$*) and the upper confidence limit for the mean inlet emission rate ($E_i$*) as applicable.

(4) The applicable potential combustion concentration.

(5) The ratio of the upper confidence limit for the mean outlet emission rate ($E_o$*) and the allowable emission rate ($E_{std}$) as applicable.

(d) If any standards under § 60.43Da are exceeded during emergency conditions because of control system malfunction, the owner or operator of the affected facility shall submit a signed statement:

(1) Indicating if emergency conditions existed and requirements under § 60.48Da(d) were met during each period, and

(2) Listing the following information:

(i) Time periods the emergency condition existed;

(ii) Electrical output and demand on the owner or operator's electric utility system and the affected facility;

(iii) Amount of power purchased from interconnected neighboring utility companies during the emergency period;

(iv) Percent reduction in emissions achieved;

(v) Atmospheric emission rate (ng/J) of the pollutant discharged; and

(vi) Actions taken to correct control system malfunction.

(e) If fuel pretreatment credit toward the $SO_2$ emission standard under § 60.43Da is claimed, the owner or operator of the affected facility shall submit a signed statement:

(1) Indicating what percentage cleaning credit was taken for the calendar quarter, and whether the credit was determined in accordance with the provisions of § 60.50Da and Method 19 of appendix A of this part; and

(2) Listing the quantity, heat content, and date each pretreated fuel shipment was received during the previous quarter; the name and location of the fuel pretreatment facility; and the total quantity and total heat content of all fuels received at the affected facility during the previous quarter.

(f) For any periods for which opacity, $SO_2$ or $NO_X$ emissions data are not available, the owner or operator of the affected facility shall submit a signed statement indicating if any changes were made in operation of the emission control system during the period of data unavailability. Operations of the control system and affected facility during periods of data unavailability are to be compared with operation of the control system and affected facility before and following the period of data unavailability.

(g) For Hg, the following information shall be reported to the Administrator:

(1) Company name and address;

(2) Date of report and beginning and ending dates of the reporting period;

(3) The applicable Hg emission limit (lb/MWh); and

(4) For each month in the reporting period:

(i) The number of unit operating hours;

(ii) The number of unit operating hours with valid data for Hg concentration, stack gas flow rate, moisture (if required), and electrical output;

(iii) The monthly Hg emission rate (lb/MWh);

(iv) The number of hours of valid data excluded from the calculation of the monthly Hg emission rate, due to unit startup, shutdown and malfunction; and

(v) The 12-month rolling average Hg emission rate (lb/MWh); and

(5) The data assessment report (DAR) required by appendix F to this part, or an equivalent summary of QA test results if the QA of part 75 of this chapter are implemented.

(h) The owner or operator of the affected facility shall submit a signed statement indicating whether:

(1) The required CEMS calibration, span, and drift checks or other periodic audits have or have not been performed as specified.

(2) The data used to show compliance was or was not obtained in accordance with approved methods and procedures

of this part and is representative of plant performance.

(3) The minimum data requirements have or have not been met; or, the minimum data requirements have not been met for errors that were unavoidable.

(4) Compliance with the standards has or has not been achieved during the reporting period.

(i) For the purposes of the reports required under § 60.7, periods of excess emissions are defined as all 6-minute periods during which the average opacity exceeds the applicable opacity standards under § 60.42Da(b). Opacity levels in excess of the applicable opacity standard and the date of such excesses are to be submitted to the Administrator each calendar quarter.

(j) The owner or operator of an affected facility shall submit the written reports required under this section and subpart A to the Administrator semiannually for each six-month period. All semiannual reports shall be postmarked by the 30th day following the end of each six-month period.

(k) The owner or operator of an affected facility may submit electronic quarterly reports for $SO_2$ and/or $NO_X$ and/or opacity and/or Hg in lieu of submitting the written reports required under paragraphs (b), (g), and (i) of this section. The format of each quarterly electronic report shall be coordinated with the permitting authority. The electronic report(s) shall be submitted no later than 30 days after the end of the calendar quarter and shall be accompanied by a certification statement from the owner or operator, indicating whether compliance with the applicable emission standards and minimum data requirements of this subpart was achieved during the reporting period. Before submitting reports in the electronic format, the owner or operator shall coordinate with the permitting authority to obtain their agreement to submit reports in this alternative format.

**§ 60.52Da Recordkeeping requirements.**

The owner or operator of an affected facility subject to the emissions limitations in § 60.45Da shall provide notifications in accordance with § 60.7(a) and shall maintain records of all information needed to demonstrate compliance including performance tests, monitoring data, fuel analyses, and calculations, consistent with the requirements of § 60.7(f).

## Subpart Db—[Amended]

■ 5. Subpart Db is revised to read as follows

## Subpart Db—Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units



## Subpart Db—Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units

**§ 60.40b Applicability and delegation of authority.**

(a) The affected facility to which this subpart applies is each steam generating unit that commences construction, modification, or reconstruction after June 19, 1984, and that has a heat input capacity from fuels combusted in the steam generating unit of greater than 29 megawatts (MW) (100 million British thermal units per hour (MMBtu/hr)).

(b) Any affected facility meeting the applicability requirements under paragraph (a) of this section and commencing construction, modification, or reconstruction after June 19, 1984, but on or before June 19, 1986, is subject to the following standards:

(1) Coal-fired affected facilities having a heat input capacity between 29 and 73 MW (100 and 250 MMBtu/hr), inclusive, are subject to the particulate matter (PM) and nitrogen oxides ($NO_X$) standards under this subpart.

(2) Coal-fired affected facilities having a heat input capacity greater than 73 MW (250 MMBtu/hr) and meeting the applicability requirements under subpart D (Standards of performance for fossil-fuel-fired steam generators; § 60.40) are subject to the PM and $NO_X$ standards under this subpart and to the sulfur dioxide ($SO_2$) standards under subpart D (§ 60.43).

(3) Oil-fired affected facilities having a heat input capacity between 29 and 73 MW (100 and 250 MMBtu/hr), inclusive, are subject to the $NO_X$ standards under this subpart.

(4) Oil-fired affected facilities having a heat input capacity greater than 73 MW (250 MMBtu/hr) and meeting the applicability requirements under subpart D (Standards of performance for fossil-fuel-fired steam generators; § 60.40) are also subject to the $NO_X$ standards under this subpart and the PM and $SO_2$ standards under subpart D (§ 60.42 and § 60.43).

(c) Affected facilities that also meet the applicability requirements under subpart J (Standards of performance for petroleum refineries; § 60.104) are subject to the PM and $NO_X$ standards under this subpart and the $SO_2$ standards under subpart J (§ 60.104).

(d) Affected facilities that also meet the applicability requirements under subpart E (Standards of performance for incinerators; § 60.50) are subject to the $NO_X$ and PM standards under this subpart.

(e) Steam generating units meeting the applicability requirements under subpart Da (Standards of performance for electric utility steam generating units; § 60.40Da) are not subject to this subpart.

(f) Any change to an existing steam generating unit for the sole purpose of combusting gases containing total reduced sulfur (TRS) as defined under § 60.281 is not considered a modification under § 60.14 and the steam generating unit is not subject to this subpart.

(g) In delegating implementation and enforcement authority to a State under section 111(c) of the Clean Air Act, the following authorities shall be retained by the Administrator and not transferred to a State.

(1) Section 60.44b(f).

(2) Section 60.44b(g).

(3) Section 60.49b(a)(4).

(h) Any affected facility that meets the applicability requirements and is subject to subpart Ea, subpart Eb, or subpart AAAA of this part is not covered by this subpart.

(i) Heat recovery steam generators that are associated with combined cycle gas turbines and that meet the applicability requirements of subpart GG or KKKK of this part are not subject to this subpart. This subpart will continue to apply to all other heat recovery steam generators that are capable of combusting more than 29 MW (100 MMBtu/hr) heat input of fossil fuel. If the heat recovery steam generator is subject to this subpart, only emissions resulting from combustion of fuels in the steam generating unit are subject to this subpart. (The gas turbine emissions are subject to subpart GG or KKKK, as applicable, of this part.)

(j) Any affected facility meeting the applicability requirements under paragraph (a) of this section and commencing construction, modification, or reconstruction after June 19, 1986 is not subject to subpart D (Standards of

Performance for Fossil-Fuel-Fired Steam Generators, § 60.40).

(k) Any affected facility that meets the applicability requirements and is subject to an EPA approved State or Federal section 111(d)/129 plan implementing subpart Cb or subpart BBBB of this part is not covered by this subpart.

**§ 60.41b Definitions.**

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

*Annual capacity factor* means the ratio between the actual heat input to a steam generating unit from the fuels listed in § 60.42b(a), § 60.43b(a), or § 60.44b(a), as applicable, during a calendar year and the potential heat input to the steam generating unit had it been operated for 8,760 hours during a calendar year at the maximum steady state design heat input capacity. In the case of steam generating units that are rented or leased, the actual heat input shall be determined based on the combined heat input from all operations of the affected facility in a calendar year.

*Byproduct/waste* means any liquid or gaseous substance produced at chemical manufacturing plants, petroleum refineries, or pulp and paper mills (except natural gas, distillate oil, or residual oil) and combusted in a steam generating unit for heat recovery or for disposal. Gaseous substances with carbon dioxide ($CO_2$) levels greater than 50 percent or carbon monoxide levels greater than 10 percent are not byproduct/waste for the purpose of this subpart.

*Chemical manufacturing plants* mean industrial plants that are classified by the Department of Commerce under Standard Industrial Classification (SIC) Code 28.

*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), coal refuse, and petroleum coke. Coal-derived synthetic fuels, including but not limited to solvent refined coal, gasified coal, coal-oil mixtures, coke oven gas, and coal-water mixtures, are also included in this definition for the purposes of this subpart.

*Coal refuse* means any byproduct of coal mining or coal cleaning operations with an ash content greater than 50 percent, by weight, and a heating value less than 13,900 kJ/kg (6,000 Btu/lb) on a dry basis.

*Cogeneration*, also known as combined heat and power, means a facility that simultaneously produces both electric (or mechanical) and useful thermal energy from the same primary energy source.

*Coke oven gas* means the volatile constituents generated in the gaseous exhaust during the carbonization of bituminous coal to form coke.

*Combined cycle system* means a system in which a separate source, such as a gas turbine, internal combustion engine, kiln, etc., provides exhaust gas to a steam generating unit.

*Conventional technology* means wet flue gas desulfurization (FGD) technology, dry FGD technology, atmospheric fluidized bed combustion technology, and oil hydrodesulfurization technology.

*Distillate oil* means fuel oils that contain 0.05 weight percent nitrogen or less and comply with the specifications for fuel oil numbers 1 and 2, as defined by the American Society of Testing and Materials in ASTM D396 (incorporated by reference, see § 60.17).

*Dry flue gas desulfurization technology* means a $SO_2$ control system that is located downstream of the steam generating unit and removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gases with an alkaline reagent and water, whether introduced separately or as a premixed slurry or solution and forming a dry powder material. This definition includes devices where the dry powder material is subsequently converted to another form. Alkaline slurries or solutions used in dry flue gas desulfurization technology include but are not limited to lime and sodium.

*Duct burner* means a device that combusts fuel and that is placed in the exhaust duct from another source, such as a stationary gas turbine, internal combustion engine, kiln, etc., to allow the firing of additional fuel to heat the exhaust gases before the exhaust gases enter a steam generating unit.

*Emerging technology* means any $SO_2$ control system that is not defined as a conventional technology under this section, and for which the owner or operator of the facility has applied to the Administrator and received approval to operate as an emerging technology under § 60.49b(a)(4).

*Federally enforceable* means all limitations and conditions that are enforceable by the Administrator, including the requirements of 40 CFR parts 60 and 61, requirements within any applicable State Implementation Plan, and any permit requirements established under 40 CFR 52.21 or under 40 CFR 51.18 and 51.24.

*Fluidized bed combustion technology* means combustion of fuel in a bed or series of beds (including but not limited to bubbling bed units and circulating bed units) of limestone aggregate (or other sorbent materials) in which these materials are forced upward by the flow of combustion air and the gaseous products of combustion.

*Fuel pretreatment* means a process that removes a portion of the sulfur in a fuel before combustion of the fuel in a steam generating unit.

*Full capacity* means operation of the steam generating unit at 90 percent or more of the maximum steady-state design heat input capacity.

*Gaseous fuel* means any fuel that is present as a gas at ISO conditions.

*Gross output* means the gross useful work performed by the steam generated. For units generating only electricity, the gross useful work performed is the gross electrical output from the turbine/generator set. For cogeneration units, the gross useful work performed is the gross electrical or mechanical output plus 75 percent of the useful thermal output measured relative to ISO conditions that is not used to generate additional electrical or mechanical output (i.e., steam delivered to an industrial process).

*Heat input* means heat derived from combustion of fuel in a steam generating unit and does not include the heat derived from preheated combustion air, recirculated flue gases, or exhaust gases from other sources, such as gas turbines, internal combustion engines, kilns, etc.

*Heat release rate* means the steam generating unit design heat input capacity (in MW or Btu/hr) divided by the furnace volume (in cubic meters or cubic feet); the furnace volume is that volume bounded by the front furnace wall where the burner is located, the furnace side waterwall, and extending to the level just below or in front of the first row of convection pass tubes.

*Heat transfer medium* means any material that is used to transfer heat from one point to another point.

*High heat release rate* means a heat release rate greater than 730,000 J/sec-$m^3$ (70,000 Btu/hr-$ft^3$).

*ISO Conditions* means a temperature of 288 Kelvin, a relative humidity of 60 percent, and a pressure of 101.3 kilopascals.

*Lignite* means a type of coal classified as lignite A or lignite B by the American Society of Testing and Materials in ASTM D388 (incorporated by reference, see § 60.17).

*Low heat release rate* means a heat release rate of 730,000 J/sec-$m^3$ (70,000 Btu/hr-$ft^3$) or less.

*Mass-feed stoker steam generating unit* means a steam generating unit where solid fuel is introduced directly into a retort or is fed directly onto a grate where it is combusted.

*Maximum heat input capacity* means the ability of a steam generating unit to combust a stated maximum amount of fuel on a steady state basis, as determined by the physical design and characteristics of the steam generating unit.

*Municipal-type solid waste* means refuse, more than 50 percent of which is waste consisting of a mixture of paper, wood, yard wastes, food wastes, plastics, leather, rubber, and other combustible materials, and noncombustible materials such as glass and rock.

*Natural gas* means: (1) A naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane; or (2) liquefied petroleum gas, as defined by the American Society for Testing and Materials in ASTM D1835 (incorporated by reference, see § 60.17).

*Noncontinental area* means the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, or the Northern Mariana Islands.

*Oil* means crude oil or petroleum or a liquid fuel derived from crude oil or petroleum, including distillate and residual oil.

*Petroleum refinery* means industrial plants as classified by the Department of Commerce under Standard Industrial Classification (SIC) Code 29.

*Potential sulfur dioxide emission rate* means the theoretical $SO_2$ emissions (nanograms per joule (ng/J) or lb/MMBtu heat input) that would result from combusting fuel in an uncleaned state and without using emission control systems.

*Process heater* means a device that is primarily used to heat a material to initiate or promote a chemical reaction in which the material participates as a reactant or catalyst.

*Pulp and paper mills* means industrial plants that are classified by the Department of Commerce under North American Industry Classification System (NAICS) Code 322 or Standard Industrial Classification (SIC) Code 26.

*Pulverized coal-fired steam generating unit* means a steam generating unit in which pulverized coal is introduced into an air stream that carries the coal to the combustion chamber of the steam generating unit where it is fired in suspension. This includes both conventional pulverized coal-fired and micropulverized coal-fired steam generating units. Residual oil means crude oil, fuel oil numbers 1 and 2 that have a nitrogen content greater than 0.05 weight percent, and all fuel oil numbers 4, 5 and 6, as defined by the American Society of Testing and Materials in ASTM D396 (incorporated by reference, see § 60.17).

*Spreader stoker steam generating unit* means a steam generating unit in which solid fuel is introduced to the combustion zone by a mechanism that throws the fuel onto a grate from above. Combustion takes place both in suspension and on the grate.

*Steam generating unit* means a device that combusts any fuel or byproduct/waste and produces steam or heats water or any other heat transfer medium. This term includes any municipal-type solid waste incinerator with a heat recovery steam generating unit or any steam generating unit that combusts fuel and is part of a cogeneration system or a combined cycle system. This term does not include process heaters as they are defined in this subpart.

*Steam generating unit operating day* means a 24-hour period between 12:00 midnight and the following midnight during which any fuel is combusted at any time in the steam generating unit. It is not necessary for fuel to be combusted continuously for the entire 24-hour period.

*Very low sulfur oil* means for units constructed, reconstructed, or modified on or before February 28, 2005, an oil that contains no more than 0.5 weight percent sulfur or that, when combusted without $SO_2$ emission control, has a $SO_2$ emission rate equal to or less than 215 ng/J (0.5 lb/MMBtu) heat input. For units constructed, reconstructed, or modified after February 28, 2005, *very low sulfur oil* means an oil that contains no more than 0.3 weight percent sulfur or that, when combusted without $SO_2$ emission control, has a $SO_2$ emission rate equal to or less than 140 ng/J (0.32 lb/MMBtu) heat input.

*Wet flue gas desulfurization technology* means a $SO_2$ control system that is located downstream of the steam generating unit and removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gas with an alkaline slurry or solution and forming a liquid material. This definition applies to devices where the aqueous liquid material product of this contact is subsequently converted to other forms. Alkaline reagents used in wet flue gas desulfurization technology include, but are not limited to, lime, limestone, and sodium.

*Wet scrubber system* means any emission control device that mixes an aqueous stream or slurry with the exhaust gases from a steam generating unit to control emissions of PM or $SO_2$.

*Wood* means wood, wood residue, bark, or any derivative fuel or residue thereof, in any form, including, but not limited to, sawdust, sanderdust, wood chips, scraps, slabs, millings, shavings, and processed pellets made from wood or other forest residues.

**§ 60.42b Standard for sulfur dioxide ($SO_2$).**

(a) Except as provided in paragraphs (b), (c), (d), or (k) of this section, on and after the date on which the performance test is completed or required to be completed under § 60.8, whichever comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, that combusts coal or oil shall cause to be discharged into the atmosphere any gases that contain $SO_2$ in excess of 87 ng/J (0.20 lb/MMBtu) or 10 percent (0.10) of the potential $SO_2$ emission rate (90 percent reduction) and the emission limit determined according to the following formula:

$$E_s = \frac{(K_a H_a + K_b H_b)}{(H_a + H_b)}$$

Where:

$E_s$ = $SO_2$ emission limit, in ng/J or lb/MMBtu heat input;

$K_a$ = 520 ng/J (or 1.2 lb/MMBtu);

$K_b$ = 340 ng/J (or 0.80 lb/MMBtu);

$H_a$ = Heat input from the combustion of coal, in J (MMBtu); and

$H_b$ = Heat input from the combustion of oil, in J (MMBtu).

Only the heat input supplied to the affected facility from the combustion of coal and oil is counted under this section. No credit is provided for the heat input to the affected facility from the combustion of natural gas, wood, municipal-type solid waste, or other fuels or heat derived from exhaust gases from other sources, such as gas turbines, internal combustion engines, kilns, etc.

(b) On and after the date on which the performance test is completed or required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, that combusts coal refuse alone in a fluidized bed combustion steam generating unit shall cause to be discharged into the atmosphere any gases that contain $SO_2$ in excess of 87 ng/J (0.20 lb/MMBtu) or 20 percent (0.20) of the potential $SO_2$ emission rate (80 percent reduction) and

520 ng/J (1.2 lb/MMBtu) heat input. If coal or oil is fired with coal refuse, the affected facility is subject to paragraph (a) or (d) of this section, as applicable.

(c) On and after the date on which the performance test is completed or is required to be completed under § 60.8, whichever comes first, no owner or operator of an affected facility that combusts coal or oil, either alone or in combination with any other fuel, and that uses an emerging technology for the control of $SO_2$ emissions, shall cause to be discharged into the atmosphere any gases that contain $SO_2$ in excess of 50 percent of the potential $SO_2$ emission rate (50 percent reduction) and that contain $SO_2$ in excess of the emission limit determined according to the following formula:

$$E_s = \frac{(K_c H_c + K_d H_d)}{(H_c + H_d)}$$

Where:

$E_s$ = $SO_2$ emission limit, in ng/J or lb/MM Btu heat input;

$K_c$ = 260 ng/J (or 0.60 lb/MMBtu);

$K_d$ = 170 ng/J (or 0.40 lb/MMBtu);

$H_c$ = Heat input from the combustion of coal, in J (MMBtu); and

$H_d$ = Heat input from the combustion of oil, in J (MMBtu).

Only the heat input supplied to the affected facility from the combustion of coal and oil is counted under this section. No credit is provided for the heat input to the affected facility from the combustion of natural gas, wood, municipal-type solid waste, or other fuels, or from the heat input derived from exhaust gases from other sources, such as gas turbines, internal combustion engines, kilns, etc.

(d) On and after the date on which the performance test is completed or required to be completed under § 60.8, whichever comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005 and listed in paragraphs (d)(1), (2), (3), or (4) of this section shall cause to be discharged into the atmosphere any gases that contain $SO_2$ in excess of 520 ng/J (1.2 lb/MMBtu) heat input if the affected facility combusts coal, or 215 ng/J (0.5 lb/MMBtu) heat input if the affected facility combusts oil other than very low sulfur oil. Percent reduction requirements are not applicable to affected facilities under paragraphs (d)(1), (2), (3) or (4) of this section.

(1) Affected facilities that have an annual capacity factor for coal and oil of 30 percent (0.30) or less and are subject to a federally enforceable permit limiting the operation of the affected facility to an annual capacity factor for coal and oil of 30 percent (0.30) or less;

(2) Affected facilities located in a noncontinental area; or

(3) Affected facilities combusting coal or oil, alone or in combination with any fuel, in a duct burner as part of a combined cycle system where 30 percent (0.30) or less of the heat entering the steam generating unit is from combustion of coal and oil in the duct burner and 70 percent (0.70) or more of the heat entering the steam generating unit is from the exhaust gases entering the duct burner; or

(4) The affected facility burns coke oven gas alone or in combination with natural gas or very low sulfur distillate oil.

(e) Except as provided in paragraph (f) of this section, compliance with the emission limits, fuel oil sulfur limits, and/or percent reduction requirements under this section are determined on a 30-day rolling average basis.

(f) Except as provided in paragraph (j)(2) of this section, compliance with the emission limits or fuel oil sulfur limits under this section is determined on a 24-hour average basis for affected facilities that (1) have a federally enforceable permit limiting the annual capacity factor for oil to 10 percent or less, (2) combust only very low sulfur oil, and (3) do not combust any other fuel.

(g) Except as provided in paragraph (i) of this section and § 60.45b(a), the $SO_2$ emission limits and percent reduction requirements under this section apply at all times, including periods of startup, shutdown, and malfunction.

(h) Reductions in the potential $SO_2$ emission rate through fuel pretreatment are not credited toward the percent reduction requirement under paragraph (c) of this section unless:

(1) Fuel pretreatment results in a 50 percent or greater reduction in potential $SO_2$ emissions and

(2) Emissions from the pretreated fuel (without combustion or post-combustion $SO_2$ control) are equal to or less than the emission limits specified in paragraph (c) of this section.

(i) An affected facility subject to paragraph (a), (b), or (c) of this section may combust very low sulfur oil or natural gas when the $SO_2$ control system is not being operated because of malfunction or maintenance of the $SO_2$ control system.

(j) Percent reduction requirements are not applicable to affected facilities combusting only very low sulfur oil. The owner or operator of an affected facility combusting very low sulfur oil shall demonstrate that the oil meets the definition of very low sulfur oil by: (1) Following the performance testing procedures as described in § 60.45b(c) or § 60.45b(d), and following the monitoring procedures as described in § 60.47b(a) or § 60.47b(b) to determine $SO_2$ emission rate or fuel oil sulfur content; or (2) maintaining fuel records as described in § 60.49b(r).

(k)(1) Except as provided in paragraphs (k)(2), (k)(3), and (k)(4) of this section, on and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commences construction, reconstruction, or modification after February 28, 2005, and that combusts coal, oil, natural gas, a mixture of these fuels, or a mixture of these fuels with any other fuels shall cause to be discharged into the atmosphere any gases that contain $SO_2$ in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 8 percent (0.08) of the potential $SO_2$ emission rate (92 percent reduction) and 520 ng/J (1.2 lb/MMBtu) heat input.

(2) Units firing only very low sulfur oil and/or a mixture of gaseous fuels with a potential $SO_2$ emission rate of 140 ng/J (0.32 lb/MMBtu) heat input or less are exempt from the $SO_2$ emissions limit in paragraph 60.42b(k)(1).

(3) Units that are located in a noncontinental area and that combust coal or oil shall not discharge any gases that contain $SO_2$ in excess of 520 ng/J (1.2 lb/MMBtu) heat input if the affected facility combusts coal, or 215 ng/J (0.50 lb/MMBtu) heat input if the affected facility combusts oil.

(4) As an alternative to meeting the requirements under paragraph (k)(1) of this section, modified facilities that combust coal or a mixture of coal with other fuels shall not cause to be discharged into the atmosphere any gases that contain $SO_2$ in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 10 percent (0.10) of the potential $SO_2$ emission rate (90 percent reduction) and 520 ng/J (1.2 lb/MMBtu) heat input.

**§ 60.43b Standard for particulate matter (PM).**

(a) On and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005 that combusts coal or combusts mixtures of coal with other fuels, shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of the following emission limits:

(1) 22 ng/J (0.051 lb/MMBtu) heat input, (i) If the affected facility combusts only coal, or

(ii) If the affected facility combusts coal and other fuels and has an annual capacity factor for the other fuels of 10 percent (0.10) or less.

(2) 43 ng/J (0.10 lb/MMBtu) heat input if the affected facility combusts coal and other fuels and has an annual capacity factor for the other fuels greater than 10 percent (0.10) and is subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor greater than 10 percent (0.10) for fuels other than coal.

(3) 86 ng/J (0.20 lb/MMBtu) heat input if the affected facility combusts coal or coal and other fuels and

(i) Has an annual capacity factor for coal or coal and other fuels of 30 percent (0.30) or less,

(ii) Has a maximum heat input capacity of 73 MW (250 MMBtu/hr) or less,

(iii) Has a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor of 30 percent (0.30) or less for coal or coal and other solid fuels, and

(iv) Construction of the affected facility commenced after June 19, 1984, and before November 25, 1986.

(4) An affected facility burning coke oven gas alone or in combination with other fuels not subject to a PM standard under § 60.43b and not using a post-combustion technology (except a wet scrubber) for reducing PM or $SO_2$ emissions is not subject to the PM limits under § 60.43b(a).

(b) On and after the date on which the performance test is completed or required to be completed under § 60.8, whichever comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, and that combusts oil (or mixtures of oil with other fuels) and uses a conventional or emerging technology to reduce $SO_2$ emissions shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 43 ng/J (0.10 lb/MMBtu) heat input.

(c) On and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, and that combusts wood, or wood with other fuels, except coal, shall cause to be discharged from that affected facility any gases that contain PM in excess of the following emission limits:

(1) 43 ng/J (0.10 lb/MMBtu) heat input if the affected facility has an annual capacity factor greater than 30 percent (0.30) for wood.

(2) 86 ng/J (0.20 lb/MMBtu) heat input if (i) The affected facility has an annual capacity factor of 30 percent (0.30) or less for wood;

(ii) Is subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor of 30 percent (0.30) or less for wood; and

(iii) Has a maximum heat input capacity of 73 MW (250 MMBtu/hr) or less.

(d) On and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that combusts municipal-type solid waste or mixtures of municipal-type solid waste with other fuels, shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of the following emission limits:

(1) 43 ng/J (0.10 lb/MMBtu) heat input;

(i) If the affected facility combusts only municipal-type solid waste; or

(ii) If the affected facility combusts municipal-type solid waste and other fuels and has an annual capacity factor for the other fuels of 10 percent (0.10) or less.

(2) 86 ng/J (0.20 lb/MMBtu) heat input if the affected facility combusts municipal-type solid waste or municipal-type solid waste and other fuels; and

(i) Has an annual capacity factor for municipal-type solid waste and other fuels of 30 percent (0.30) or less;

(ii) Has a maximum heat input capacity of 73 MW (250 MMBtu/hr) or less;

(iii) Has a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor of 30 percent (0.30) or less for municipal-type solid waste, or municipal-type solid waste and other fuels; and

(iv) Construction of the affected facility commenced after June 19, 1984, but on or before November 25, 1986.

(e) For the purposes of this section, the annual capacity factor is determined by dividing the actual heat input to the steam generating unit during the calendar year from the combustion of coal, wood, or municipal-type solid waste, and other fuels, as applicable, by the potential heat input to the steam generating unit if the steam generating unit had been operated for 8,760 hours at the maximum heat input capacity.

(f) On and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that combusts coal, oil, wood, or mixtures of these fuels with any other fuels shall cause to be discharged into the atmosphere any gases that exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity.

(g) The PM and opacity standards apply at all times, except during periods of startup, shutdown or malfunction.

(h)(1) Except as provided in paragraphs (h)(2), (h)(3), (h)(4), and (h)(5) of this section, on and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification after February 28, 2005, and that combusts coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 13 ng/J (0.030 lb/MMBtu) heat input,

(2) As an alternative to meeting the requirements of paragraph (h)(1) of this section, the owner or operator of an affected facility for which modification commenced after February 28, 2005, may elect to meet the requirements of this paragraph. On and after the date on which the initial performance test is completed or required to be completed under § 60.8, no owner or operator of an affected facility that commences modification after February 28, 2005 shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of both:

(i) 22 ng/J (0.051 lb/MMBtu) heat input derived from the combustion of coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels; and

(ii) 0.2 percent of the combustion concentration (99.8 percent reduction) when combusting coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels.

(3) On and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commences modification after February 28, 2005, and that combusts over 30 percent wood (by heat input) on

an annual basis and has a maximum heat input capacity of 73 MW (250 MMBtu/h) or less shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 43 ng/J (0.10 lb/MMBtu) heat input.

(4) On and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commences modification after February 28, 2005, and that combusts over 30 percent wood (by heat input) on an annual basis and has a maximum heat input capacity greater than 73 MW (250 MMBtu/h) shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 37 ng/J (0.085 lb/MMBtu) heat input.

(5) On and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, an owner or operator of an affected facility that commences construction, reconstruction, or modification after February 28, 2005, and that combusts only oil that contains no more than 0.3 weight percent sulfur, coke oven gas, a mixture of these fuels, or either fuel (or a mixture of these fuels) in combination with other fuels not subject to a PM standard under § 60.43b and not using a post-combustion technology (except a wet scrubber) to reduce $SO_2$ or PM emissions is not subject to the PM limits under § 60.43b(h)(1).

### § 60.44b Standard for nitrogen oxides ($NO_X$).

(a) Except as provided under paragraphs (k) and (l) of this section, on and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that is subject to the provisions of this section and that combusts only coal, oil, or natural gas shall cause to be discharged into the atmosphere from that affected facility any gases that contain $NO_X$ (expressed as $NO_2$) in excess of the following emission limits:

| Fuel/steam generating unit type | Nitrogen oxide emission limits (expressed as $NO_2$) heat input | |
|---|---|---|
| | ng/J | lb/MMBTu |
| (1) Natural gas and distillate oil, except (4): | | |
| (i) Low heat release rate | 43 | 0.10 |
| (ii) High heat release rate | 86 | 0.20 |
| (2) Residual oil: | | |
| (i) Low heat release rate | 130 | 0.30 |
| (ii) High heat release rate | 170 | 0.40 |
| (3) Coal: | | |
| (i) Mass-feed stoker | 210 | 0.50 |
| (ii) Spreader stoker and fluidized bed combustion | 260 | 0.60 |
| (iii) Pulverized coal | 300 | 0.70 |
| (iv) Lignite, except (v) | 260 | 0.60 |
| (v) Lignite mined in North Dakota, South Dakota, or Montana and combusted in a slag tap furnace | 340 | 0.80 |
| (vi) Coal-derived synthetic fuels | 210 | 0.50 |
| (4) Duct burner used in a combined cycle system: | | |
| (i) Natural gas and distillate oil | 86 | 0.20 |
| (ii) Residual oil | 170 | 0.40 |

(b) Except as provided under paragraphs (k) and (l) of this section, on and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that simultaneously combusts mixtures of coal, oil, or natural gas shall cause to be discharged into the atmosphere from that affected facility any gases that contain $NO_X$ in excess of a limit determined by the use of the following formula:

$$E_n = \frac{(EL_{go}H_{go}) + (EL_{ro}H_{ro}) + (EL_cH_c)}{(H_{go} + H_{ro} + H_c)}$$

Where:

$E_n$ = $NO_X$ emission limit (expressed as $NO_2$), ng/J (lb/MMBtu);

$EL_{go}$ = Appropriate emission limit from paragraph (a)(1) for combustion of natural gas or distillate oil, ng/J (lb/MMBtu);

$H_{go}$ = Heat input from combustion of natural gas or distillate oil, J (MMBtu);

$EL_{ro}$ = Appropriate emission limit from paragraph (a)(2) for combustion of residual oil, ng/J (lb/MMBtu);

$H_{ro}$ = Heat input from combustion of residual oil, J (MMBtu);

$EL_c$ = Appropriate emission limit from paragraph (a)(3) for combustion of coal, ng/J (lb/MMBtu); and

$H_c$ = Heat input from combustion of coal, J (MMBtu).

(c) Except as provided under paragraph (l) of this section, on and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that simultaneously combusts coal or oil, or a mixture of these fuels with natural gas, and wood, municipal-type solid waste, or any other fuel shall cause to be discharged into the atmosphere any gases that contain $NO_X$ in excess of the emission limit for the coal or oil, or mixtures of these fuels with natural gas combusted in the affected facility, as determined pursuant to paragraph (a) or (b) of this section, unless the affected facility has an annual capacity factor for coal or oil, or mixture of these fuels with natural gas of 10 percent (0.10) or less and is subject to a federally enforceable requirement that limits operation of the affected facility to an annual capacity factor of 10 percent (0.10) or less for coal, oil, or a mixture of these fuels with natural gas.

(d) On and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that simultaneously combusts natural gas with wood, municipal-type solid waste, or other solid fuel, except coal, shall cause to be discharged into the atmosphere from that affected facility any gases that contain $NO_X$ in excess of 130 ng/J (0.30 lb/MMBtu) heat input unless the affected facility has an annual capacity factor for natural gas of

10 percent (0.10) or less and is subject to a federally enforceable requirement that limits operation of the affected facility to an annual capacity factor of 10 percent (0.10) or less for natural gas.

(e) Except as provided under paragraph (l) of this section, on and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that simultaneously combusts coal, oil, or natural gas with byproduct/waste shall cause to be discharged into the atmosphere any gases that contain $NO_X$ in excess of the emission limit determined by the following formula unless the affected facility has an annual capacity factor for coal, oil, and natural gas of 10 percent (0.10) or less and is subject to a federally enforceable requirement that limits operation of the affected facility to an annual capacity factor of 10 percent (0.10) or less:

$$E_n = \frac{(EL_{go}H_{go}) + (EL_{ro}H_{ro}) + (EL_cH_c)}{(H_{go} + H_{ro} + H_c)}$$

Where:

$E_n$ = $NO_X$ emission limit (expressed as $NO_2$), ng/J (lb/MMBtu);

$EL_{go}$ = Appropriate emission limit from paragraph (a)(1) for combustion of natural gas or distillate oil, ng/J (lb/MMBtu);

$H_{go}$ = Heat input from combustion of natural gas, distillate oil and gaseous byproduct/waste, J (MMBtu);

$EL_{ro}$ = Appropriate emission limit from paragraph (a)(2) for combustion of residual oil and/or byproduct/waste, ng/J (lb/MMBtu);

$H_{ro}$ = Heat input from combustion of residual oil, J (MMBtu);

$EL_c$ = Appropriate emission limit from paragraph (a)(3) for combustion of coal, ng/J (lb/MMBtu); and

$H_c$ = Heat input from combustion of coal, J (MMBtu).

(f) Any owner or operator of an affected facility that combusts byproduct/waste with either natural gas or oil may petition the Administrator within 180 days of the initial startup of the affected facility to establish a $NO_X$ emission limit that shall apply specifically to that affected facility when the byproduct/waste is combusted. The petition shall include sufficient and appropriate data, as determined by the Administrator, such as $NO_X$ emissions from the affected facility, waste composition (including nitrogen content), and combustion conditions to allow the Administrator to confirm that the affected facility is unable to comply with the emission limits in paragraph (e) of this section and to determine the appropriate emission limit for the affected facility.

(1) Any owner or operator of an affected facility petitioning for a facility-specific $NO_X$ emission limit under this section shall:

(i) Demonstrate compliance with the emission limits for natural gas and distillate oil in paragraph (a)(1) of this section or for residual oil in paragraph (a)(2) or (l)(1) of this section, as appropriate, by conducting a 30-day performance test as provided in § 60.46b(e). During the performance test only natural gas, distillate oil, or residual oil shall be combusted in the affected facility; and

(ii) Demonstrate that the affected facility is unable to comply with the emission limits for natural gas and distillate oil in paragraph (a)(1) of this section or for residual oil in paragraph (a)(2) or (l)(1) of this section, as appropriate, when gaseous or liquid byproduct/waste is combusted in the affected facility under the same conditions and using the same technological system of emission reduction applied when demonstrating compliance under paragraph (f)(1)(i) of this section.

(2) The $NO_X$ emission limits for natural gas or distillate oil in paragraph (a)(1) of this section or for residual oil in paragraph (a)(2) or (l)(1) of this section, as appropriate, shall be applicable to the affected facility until and unless the petition is approved by the Administrator. If the petition is approved by the Administrator, a facility-specific $NO_X$ emission limit will be established at the $NO_X$ emission level achievable when the affected facility is combusting oil or natural gas and byproduct/waste in a manner that the Administrator determines to be consistent with minimizing $NO_X$ emissions. In lieu of amending this subpart, a letter will be sent to the facility describing the facility-specific $NO_X$ limit. The facility shall use the compliance procedures detailed in the letter and make the letter available to the public. If the Administrator determines it is appropriate, the conditions and requirements of the letter can be reviewed and changed at any point.

(g) Any owner or operator of an affected facility that combusts hazardous waste (as defined by 40 CFR part 261 or 40 CFR part 761) with natural gas or oil may petition the Administrator within 180 days of the initial startup of the affected facility for a waiver from compliance with the $NO_X$ emission limit that applies specifically to that affected facility. The petition must include sufficient and appropriate data, as determined by the Administrator, on $NO_X$ emissions from the affected facility, waste destruction efficiencies, waste composition (including nitrogen content), the quantity of specific wastes to be combusted and combustion conditions to allow the Administrator to determine if the affected facility is able to comply with the $NO_X$ emission limits required by this section. The owner or operator of the affected facility shall demonstrate that when hazardous waste is combusted in the affected facility, thermal destruction efficiency requirements for hazardous waste specified in an applicable federally enforceable requirement preclude compliance with the $NO_X$ emission limits of this section. The $NO_X$ emission limits for natural gas or distillate oil in paragraph (a)(1) of this section or for residual oil in paragraph (a)(2) or (l)(1) of this section, as appropriate, are applicable to the affected facility until and unless the petition is approved by the Administrator. (See 40 CFR 761.70 for regulations applicable to the incineration of materials containing polychlorinated biphenyls (PCB's).) In lieu of amending this subpart, a letter will be sent to the facility describing the facility-specific $NO_X$ limit. The facility shall use the compliance procedures detailed in the letter and make the letter available to the public. If the Administrator determines it is appropriate, the conditions and requirements of the letter can be reviewed and changed at any point.

(h) For purposes of paragraph (i) of this section, the $NO_X$ standards under this section apply at all times including periods of startup, shutdown, or malfunction.

(i) Except as provided under paragraph (j) of this section, compliance with the emission limits under this section is determined on a 30-day rolling average basis.

(j) Compliance with the emission limits under this section is determined on a 24-hour average basis for the initial performance test and on a 3-hour average basis for subsequent performance tests for any affected facilities that:

(1) Combust, alone or in combination, only natural gas, distillate oil, or residual oil with a nitrogen content of 0.30 weight percent or less;

(2) Have a combined annual capacity factor of 10 percent or less for natural gas, distillate oil, and residual oil with a nitrogen content of 0.30 weight percent or less; and

(3) Are subject to a federally enforceable requirement limiting operation of the affected facility to the

firing of natural gas, distillate oil, and/or residual oil with a nitrogen content of 0.30 weight percent or less and limiting operation of the affected facility to a combined annual capacity factor of 10 percent or less for natural gas, distillate oil, and residual oil with a nitrogen content of 0.30 weight percent or less.

(k) Affected facilities that meet the criteria described in paragraphs (j)(1), (2), and (3) of this section, and that have a heat input capacity of 73 MW (250 MMBtu/hr) or less, are not subject to the $NO_X$ emission limits under this section.

(l) On and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction or reconstruction after July 9, 1997 shall cause to be discharged into the atmosphere from that affected facility any gases that contain $NO_X$ (expressed as $NO_2$) in excess of the following limits:

(1) If the affected facility combusts coal, oil, or natural gas, or a mixture of these fuels, or with any other fuels: A limit of 86 ng/J (0.20 lb/MMBtu) heat input unless the affected facility has an annual capacity factor for coal, oil, and natural gas of 10 percent (0.10) or less and is subject to a federally enforceable requirement that limits operation of the facility to an annual capacity factor of 10 percent (0.10) or less for coal, oil, and natural gas; or

(2) If the affected facility has a low heat release rate and combusts natural gas or distillate oil in excess of 30 percent of the heat input on a 30-day rolling average from the combustion of all fuels, a limit determined by use of the following formula:

$$E_n = \frac{(0.10 \times H_{go}) + (0.20 \times H_r)}{(H_{go} + H_r)}$$

Where:

$E_n$ = $NO_X$ emission limit, (lb/MMBtu);
$H_{go}$ = 30-day heat input from combustion of natural gas or distillate oil; and
$H_r$ = 30-day heat input from combustion of any other fuel.

(3) After February 27, 2006, units where more than 10 percent of total annual output is electrical or mechanical may comply with an optional limit of 270 ng/J (2.1 lb/MWh) gross energy output, based on a 30-day rolling average. Units complying with this output-based limit must demonstrate compliance according to the procedures of § 60.48Da(i) of subpart Da of this part, and must monitor emissions according to § 60.49Da(c), (k), through (n) of subpart Da of this part.

**§ 60.45b Compliance and performance test methods and procedures for sulfur dioxide.**

(a) The $SO_2$ emission standards under § 60.42b apply at all times. Facilities burning coke oven gas alone or in combination with any other gaseous fuels or distillate oil and complying with the fuel based limit under § 60.42b(d) or § 60.42b(k)(2) are allowed to exceed the limit 30 operating days per calendar year for by-product plant maintenance.

(b) In conducting the performance tests required under § 60.8, the owner or operator shall use the methods and procedures in appendix A (including fuel certification and sampling) of this part or the methods and procedures as specified in this section, except as provided in § 60.8(b). Section 60.8(f) does not apply to this section. The 30-day notice required in § 60.8(d) applies only to the initial performance test unless otherwise specified by the Administrator.

(c) The owner or operator of an affected facility shall conduct performance tests to determine compliance with the percent of potential $SO_2$ emission rate (% $P_s$) and the $SO_2$ emission rate ($E_s$) pursuant to § 60.42b following the procedures listed below, except as provided under paragraph (d) and (k) of this section.

(1) The initial performance test shall be conducted over 30 consecutive operating days of the steam generating unit. Compliance with the $SO_2$ standards shall be determined using a 30-day average. The first operating day included in the initial performance test shall be scheduled within 30 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of the facility.

(2) If only coal, only oil, or a mixture of coal and oil is combusted, the following procedures are used:

(i) The procedures in Method 19 of appendix A of this part are used to determine the hourly $SO_2$ emission rate ($E_{ho}$) and the 30-day average emission rate ($E_{ao}$). The hourly averages used to compute the 30-day averages are obtained from the continuous emission monitoring system (CEMS) of § 60.47b (a) or (b).

(ii) The percent of potential $SO_2$ emission rate (%$P_s$) emitted to the atmosphere is computed using the following formula:

$$\%P_s = 100\left(1 - \frac{\%R_g}{100}\right)\left(1 - \frac{\%R_f}{100}\right)$$

Where:

%$P_s$ = Potential $SO_2$ emission rate, percent;
%$R_g$ = $SO_2$ removal efficiency of the control device as determined by Method 19 of appendix A of this part, in percent; and
%$R_f$ = $SO_2$ removal efficiency of fuel pretreatment as determined by Method 19 of appendix A of this part, in percent.

(3) If coal or oil is combusted with other fuels, the same procedures required in paragraph (c)(2) of this section are used, except as provided in the following:

(i) An adjusted hourly $SO_2$ emission rate ($E_{ho}°$) is used in Equation 19–19 of Method 19 of appendix A of this part to compute an adjusted 30-day average emission rate ($E_{ao}°$). The Eho° is computed using the following formula:

$$E_{ho}^{o} = \frac{E_{ho} - E_w(1 - X_k)}{X_k}$$

Where:

$E_{ho}°$ = Adjusted hourly $SO_2$ emission rate, ng/J (lb/MMBtu);
$E_{ho}$ = Hourly $SO_2$ emission rate, ng/J (lb/MMBtu);
$E_w$ = $SO_2$ concentration in fuels other than coal and oil combusted in the affected facility, as determined by the fuel sampling and analysis procedures in Method 19 of appendix A of this part, ng/J (lb/MMBtu). The value $E_w$ for each fuel lot is used for each hourly average during the time that the lot is being combusted; and
$X_k$ = Fraction of total heat input from fuel combustion derived from coal, oil, or coal and oil, as determined by applicable procedures in Method 19 of appendix A of this part.

(ii) To compute the percent of potential $SO_2$ emission rate (%$P_s$), an adjusted %$R_g$ (%$R_g°$) is computed from the adjusted $E_{ao}°$ from paragraph (b)(3)(i) of this section and an adjusted average $SO_2$ inlet rate ($E_{ai}°$) using the following formula:

$$\%R_g^o = 100\left(1.0 - \frac{E_{ao}^o}{E_{ai}^o}\right)$$

To compute $E_{ai}°$, an adjusted hourly $SO_2$ inlet rate ($E_{hi}°$) is used. The $E_{hi}°$ is computed using the following formula:

$$E_{hi}^{o} = \frac{E_{hi} - E_w(1 - X_k)}{X_k}$$

Where:

$E_{hi}°$ = Adjusted hourly $SO_2$ inlet rate, ng/J (lb/MMBtu); and
$E_{hi}$ = Hourly $SO_2$ inlet rate, ng/J (lb/MMBtu).

(4) The owner or operator of an affected facility subject to paragraph (b)(3) of this section does not have to measure parameters $E_w$ or $X_k$ if the owner or operator elects to assume that

$X_k = 1.0$. Owners or operators of affected facilities who assume $X_k = 1.0$ shall:

(i) Determine $\%P_s$ following the procedures in paragraph (c)(2) of this section; and

(ii) Sulfur dioxide emissions ($E_s$) are considered to be in compliance with $SO_2$ emission limits under § 60.42b.

(5) The owner or operator of an affected facility that qualifies under the provisions of § 60.42b(d) does not have to measure parameters $E_w$ or $X_k$ under paragraph (b)(3) of this section if the owner or operator of the affected facility elects to measure $SO_2$ emission rates of the coal or oil following the fuel sampling and analysis procedures under Method 19 of appendix A of this part.

(d) Except as provided in paragraph (j) of this section, the owner or operator of an affected facility that combusts only very low sulfur oil, has an annual capacity factor for oil of 10 percent (0.10) or less, and is subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor for oil of 10 percent (0.10) or less shall:

(1) Conduct the initial performance test over 24 consecutive steam generating unit operating hours at full load;

(2) Determine compliance with the standards after the initial performance test based on the arithmetic average of the hourly emissions data during each steam generating unit operating day if a CEMS is used, or based on a daily average if Method 6B of appendix A of this part or fuel sampling and analysis procedures under Method 19 of appendix A of this part are used.

(e) The owner or operator of an affected facility subject to § 60.42b(d)(1) shall demonstrate the maximum design capacity of the steam generating unit by operating the facility at maximum capacity for 24 hours. This demonstration will be made during the initial performance test and a subsequent demonstration may be requested at any other time. If the 24-hour average firing rate for the affected facility is less than the maximum design capacity provided by the manufacturer of the affected facility, the 24-hour average firing rate shall be used to determine the capacity utilization rate for the affected facility, otherwise the maximum design capacity provided by the manufacturer is used.

(f) For the initial performance test required under § 60.8, compliance with the $SO_2$ emission limits and percent reduction requirements under § 60.42b is based on the average emission rates and the average percent reduction for $SO_2$ for the first 30 consecutive steam generating unit operating days, except as provided under paragraph (d) of this section. The initial performance test is the only test for which at least 30 days prior notice is required unless otherwise specified by the Administrator. The initial performance test is to be scheduled so that the first steam generating unit operating day of the 30 successive steam generating unit operating days is completed within 30 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of the facility. The boiler load during the 30-day period does not have to be the maximum design load, but must be representative of future operating conditions and include at least one 24-hour period at full load.

(g) After the initial performance test required under § 60.8, compliance with the $SO_2$ emission limits and percent reduction requirements under § 60.42b is based on the average emission rates and the average percent reduction for $SO_2$ for 30 successive steam generating unit operating days, except as provided under paragraph (d). A separate performance test is completed at the end of each steam generating unit operating day after the initial performance test, and a new 30-day average emission rate and percent reduction for $SO_2$ are calculated to show compliance with the standard.

(h) Except as provided under paragraph (i) of this section, the owner or operator of an affected facility shall use all valid $SO_2$ emissions data in calculating $\%P_s$ and $E_{ho}$ under paragraph (c), of this section whether or not the minimum emissions data requirements under § 60.46b are achieved. All valid emissions data, including valid $SO_2$ emission data collected during periods of startup, shutdown and malfunction, shall be used in calculating $\%P_s$ and $E_{ho}$ pursuant to paragraph (c) of this section.

(i) During periods of malfunction or maintenance of the $SO_2$ control systems when oil is combusted as provided under § 60.42b(i), emission data are not used to calculate $\%P_s$ or $E_s$ under § 60.42b(a), (b) or (c), however, the emissions data are used to determine compliance with the emission limit under § 60.42b(i).

(j) The owner or operator of an affected facility that combusts very low sulfur oil is not subject to the compliance and performance testing requirements of this section if the owner or operator obtains fuel receipts as described in § 60.49b(r).

(k) The owner or operator of an affected facility seeking to demonstrate compliance under §§ 60.42b(d)(4), 60.42b(j), and 60.42b(k)(2) shall follow the applicable procedures under § 60.49b(r).

**§ 60.46b Compliance and performance test methods and procedures for particulate matter and nitrogen oxides.**

(a) The PM emission standards and opacity limits under § 60.43b apply at all times except during periods of startup, shutdown, or malfunction. The $NO_X$ emission standards under § 60.44b apply at all times.

(b) Compliance with the PM emission standards under § 60.43b shall be determined through performance testing as described in paragraph (d) of this section, except as provided in paragraph (i) of this section.

(c) Compliance with the $NO_X$ emission standards under § 60.44b shall be determined through performance testing under paragraph (e) or (f), or under paragraphs (g) and (h) of this section, as applicable.

(d) To determine compliance with the PM emission limits and opacity limits under § 60.43b, the owner or operator of an affected facility shall conduct an initial performance test as required under § 60.8, and shall conduct subsequent performance tests as requested by the Administrator, using the following procedures and reference methods:

(1) Method 3B of appendix A of this part is used for gas analysis when applying Method 5 or 17 of appendix A of this part.

(2) Method 5, 5B, or 17 of appendix A of this part shall be used to measure the concentration of PM as follows:

(i) Method 5 of appendix A of this part shall be used at affected facilities without wet flue gas desulfurization (FGD) systems; and

(ii) Method 17 of appendix A of this part may be used at facilities with or without wet scrubber systems provided the stack gas temperature does not exceed a temperature of 160 °C (32 °F). The procedures of sections 2.1 and 2.3 of Method 5B of appendix A of this part may be used in Method 17 of appendix A of this part only if it is used after a wet FGD system. Do not use Method 17 of appendix A of this part after wet FGD systems if the effluent is saturated or laden with water droplets.

(iii) Method 5B of appendix A of this part is to be used only after wet FGD systems.

(3) Method 1 of appendix A of this part is used to select the sampling site and the number of traverse sampling points. The sampling time for each run is at least 120 minutes and the minimum sampling volume is 1.7 dscm (60 dscf) except that smaller sampling

times or volumes may be approved by the Administrator when necessitated by process variables or other factors.

(4) For Method 5 of appendix A of this part, the temperature of the sample gas in the probe and filter holder is monitored and is maintained at 160±14 °C (320±25 °F).

(5) For determination of PM emissions, the oxygen ($O_2$) or $CO_2$ sample is obtained simultaneously with each run of Method 5, 5B, or 17 of appendix A of this part by traversing the duct at the same sampling location.

(6) For each run using Method 5, 5B, or 17 of appendix A of this part, the emission rate expressed in ng/J heat input is determined using:

(i) The $O_2$ or $CO_2$ measurements and PM measurements obtained under this section;

(ii) The dry basis F factor; and

(iii) The dry basis emission rate calculation procedure contained in Method 19 of appendix A of this part.

(7) Method 9 of appendix A of this part is used for determining the opacity of stack emissions.

(e) To determine compliance with the emission limits for $NO_X$ required under § 60.44b, the owner or operator of an affected facility shall conduct the performance test as required under § 60.8 using the continuous system for monitoring $NO_X$ under § 60.48(b).

(1) For the initial compliance test, $NO_X$ from the steam generating unit are monitored for 30 successive steam generating unit operating days and the 30-day average emission rate is used to determine compliance with the $NO_X$ emission standards under § 60.44b. The 30-day average emission rate is calculated as the average of all hourly emissions data recorded by the monitoring system during the 30-day test period.

(2) Following the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, the owner or operator of an affected facility which combusts coal or which combusts residual oil having a nitrogen content greater than 0.30 weight percent shall determine compliance with the $NO_X$ emission standards under § 60.44b on a continuous basis through the use of a 30-day rolling average emission rate. A new 30-day rolling average emission rate is calculated each steam generating unit operating day as the average of all of the hourly $NO_X$ emission data for the preceding 30 steam generating unit operating days.

(3) Following the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, the owner or operator of an affected facility that has a heat input capacity greater than 73 MW (250 MMBtu/hr) and that combusts natural gas, distillate oil, or residual oil having a nitrogen content of 0.30 weight percent or less shall determine compliance with the $NO_X$ standards under § 60.44b on a continuous basis through the use of a 30-day rolling average emission rate. A new 30-day rolling average emission rate is calculated each steam generating unit operating day as the average of all of the hourly $NO_X$ emission data for the preceding 30 steam generating unit operating days.

(4) Following 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 of an affected facility that has a heat input capacity of 73 MW (250 MMBtu/hr) or less and that combusts natural gas, distillate oil, or residual oil having a nitrogen content of 0.30 weight percent or less shall upon request determine compliance with the $NO_X$ standards under § 60.44b through the use of a 30-day performance test. During periods when performance tests are not requested, $NO_X$ emissions data collected pursuant to § 60.48b(g)(1) or § 60.48b(g)(2) are used to calculate a 30-day rolling average emission rate on a daily basis and used to prepare excess emission reports, but will not be used to determine compliance with the $NO_X$ emission standards. A new 30-day rolling average emission rate is calculated each steam generating unit operating day as the average of all of the hourly $NO_X$ emission data for the preceding 30 steam generating unit operating days.

(5) If the owner or operator of an affected facility that combusts residual oil does not sample and analyze the residual oil for nitrogen content, as specified in § 60.49b(e), the requirements of § 60.48b(g)(1) apply and the provisions of § 60.48b(g)(2) are inapplicable.

(f) To determine compliance with the emissions limits for $NO_X$ required by § 60.44b(a)(4) or § 60.44b(l) for duct burners used in combined cycle systems, either of the procedures described in paragraph (f)(1) or (2) of this section may be used:

(1) The owner or operator of an affected facility shall conduct the performance test required under § 60.8 as follows:

(i) The emissions rate (E) of $NO_X$ shall be computed using Equation 1 in this section:

$$E = E_{sg} + \left(\frac{H_g}{H_b}\right)\left(E_{sg} - E_g\right) \qquad \text{(Eq.1)}$$

Where:

E = Emissions rate of $NO_X$ from the duct burner, ng/J (lb/MMBtu) heat input;

$E_{sg}$ = Combined effluent emissions rate, in ng/J (lb/MMBtu) heat input using appropriate F factor as described in Method 19 of appendix A of this part;

$H_g$ = Heat input rate to the combustion turbine, in J/hr (MMBtu/hr);

$H_b$ = Heat input rate to the duct burner, in J/hr (MMBtu/hr); and

$E_g$ = Emissions rate from the combustion turbine, in ng/J (lb/MMBtu) heat input calculated using appropriate F factor as described in Method 19 of appendix A of this part.

(ii) Method 7E of appendix A of this part shall be used to determine the $NO_X$ concentrations. Method 3A or 3B of appendix A of this part shall be used to determine $O_2$ concentration.

(iii) The owner or operator shall identify and demonstrate to the Administrator's satisfaction suitable methods to determine the average hourly heat input rate to the combustion turbine and the average hourly heat input rate to the affected duct burner.

(iv) Compliance with the emissions limits under § 60.44b(a)(4) or § 60.44b(l) is determined by the three-run average (nominal 1-hour runs) for the initial and subsequent performance tests; or

(2) The owner or operator of an affected facility may elect to determine compliance on a 30-day rolling average basis by using the CEMS specified under § 60.48b for measuring $NO_X$ and $O_2$ and meet the requirements of § 60.48b. The sampling site shall be located at the outlet from the steam generating unit. The $NO_X$ emissions rate at the outlet from the steam generating unit shall constitute the $NO_X$ emissions rate from the duct burner of the combined cycle system.

(g) The owner or operator of an affected facility described in § 60.44b(j) or § 60.44b(k) shall demonstrate the maximum heat input capacity of the steam generating unit by operating the facility at maximum capacity for 24 hours. The owner or operator of an affected facility shall determine the maximum heat input capacity using the heat loss method described in sections 5 and 7.3 of the ASME *Power Test Codes* 4.1 (incorporated by reference, see § 60.17). This demonstration of maximum heat input capacity shall be made during the initial performance test for affected facilities that meet the criteria of § 60.44b(j). It shall be made within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not

later than 180 days after initial start-up of each facility, for affected facilities meeting the criteria of § 60.44b(k). Subsequent demonstrations may be required by the Administrator at any other time. If this demonstration indicates that the maximum heat input capacity of the affected facility is less than that stated by the manufacturer of the affected facility, the maximum heat input capacity determined during this demonstration shall be used to determine the capacity utilization rate for the affected facility. Otherwise, the maximum heat input capacity provided by the manufacturer is used.

(h) The owner or operator of an affected facility described in § 60.44b(j) that has a heat input capacity greater than 73 MW (250 MMBtu/hr) shall:

(1) Conduct an initial performance test as required under § 60.8 over a minimum of 24 consecutive steam generating unit operating hours at maximum heat input capacity to demonstrate compliance with the $NO_X$ emission standards under § 60.44b using Method 7, 7A, 7E of appendix A of this part, or other approved reference methods; and

(2) Conduct subsequent performance tests once per calendar year or every 400 hours of operation (whichever comes first) to demonstrate compliance with the $NO_X$ emission standards under § 60.44b over a minimum of 3 consecutive steam generating unit operating hours at maximum heat input capacity using Method 7, 7A, 7E of appendix A of this part, or other approved reference methods.

(i) The owner or operator of an affected facility seeking to demonstrate compliance under paragraph § 60.43b(h)(5) shall follow the applicable procedures under § 60.49b(r).

(j) In place of PM testing with EPA Reference Method 5, 5B, or 17 of appendix A of this part, an owner or operator may elect to install, calibrate, maintain, and operate a CEMS for monitoring PM emissions discharged to the atmosphere and record the output of the system. The owner or operator of an affected facility who elects to continuously monitor PM emissions instead of conducting performance testing using EPA Method 5, 5B, or 17 of appendix A of this part shall comply with the requirements specified in paragraphs (j)(1) through (j)(13) of this section.

(1) Notify the Administrator one month before starting use of the system.

(2) Notify the Administrator one month before stopping use of the system.

(3) The monitor shall be installed, evaluated, and operated in accordance with § 60.13 of subpart A of this part.

(4) The initial performance evaluation shall be completed no later than 180 days after the date of initial startup of the affected facility, as specified under § 60.8 of subpart A of this part or within 180 days of notification to the Administrator of use of the CEMS if the owner or operator was previously determining compliance by Method 5, 5B, or 17 of appendix A of this part performance tests, whichever is later.

(5) The owner or operator of an affected facility shall conduct an initial performance test for PM emissions as required under § 60.8 of subpart A of this part. Compliance with the PM emission limit shall be determined by using the CEMS specified in paragraph (j) of this section to measure PM and calculating a 24-hour block arithmetic average emission concentration using EPA Reference Method 19 of appendix A of this part, section 4.1.

(6) Compliance with the PM emission limit shall be determined based on the 24-hour daily (block) average of the hourly arithmetic average emission concentrations using CEMS outlet data.

(7) At a minimum, valid CEMS hourly averages shall be obtained as specified in paragraphs (j)(7)(i) of this section for 75 percent of the total operating hours per 30-day rolling average.

(i) At least two data points per hour shall be used to calculate each 1-hour arithmetic average.

(ii) [Reserved]

(8) The 1-hour arithmetic averages required under paragraph (j)(7) of this section shall be expressed in ng/J or lb/MMBtu heat input and shall be used to calculate the boiler operating day daily arithmetic average emission concentrations. The 1-hour arithmetic averages shall be calculated using the data points required under § 60.13(e)(2) of subpart A of this part.

(9) All valid CEMS data shall be used in calculating average emission concentrations even if the minimum CEMS data requirements of paragraph (j)(7) of this section are not met.

(10) The CEMS shall be operated according to Performance Specification 11 in appendix B of this part.

(11) During the correlation testing runs of the CEMS required by Performance Specification 11 in appendix B of this part, PM and $O_2$ (or $CO_2$) data shall be collected concurrently (or within a 30-to 60-minute period) by both the continuous emission monitors and the test methods specified in paragraphs (j)(7)(i) of this section.

(i) For PM, EPA Reference Method 5, 5B, or 17 of appendix A of this part shall be used.

(ii) For $O_2$ (or $CO_2$), EPA reference Method 3, 3A, or 3B of appendix A of this part, as applicable shall be used.

(12) Quarterly accuracy determinations and daily calibration drift tests shall be performed in accordance with procedure 2 in appendix F of this part. Relative Response Audit's must be performed annually and Response Correlation Audits must be performed every 3 years.

(13) When PM emissions data are not obtained because of CEMS breakdowns, repairs, calibration checks, and zero and span adjustments, emissions data shall be obtained by using other monitoring systems as approved by the Administrator or EPA Reference Method 19 of appendix A of this part to provide, as necessary, valid emissions data for a minimum of 75 percent of total operating hours per 30-day rolling average.

**§ 60.47b Emission monitoring for sulfur dioxide.**

(a) Except as provided in paragraphs (b), (f), and (h) of this section, the owner or operator of an affected facility subject to the $SO_2$ standards under § 60.42b shall install, calibrate, maintain, and operate CEMS for measuring $SO_2$ concentrations and either $O_2$ or $CO_2$ concentrations and shall record the output of the systems. For units complying with the percent reduction standard, the $SO_2$ and either $O_2$ or $CO_2$ concentrations shall both be monitored at the inlet and outlet of the $SO_2$ control device. If the owner or operator has installed and certified $SO_2$ and $O_2$ or $CO_2$ CEMS according to the requirements of § 75.20(c)(1) of this chapter and appendix A to part 75 of this chapter, and is continuing to meet the ongoing quality assurance requirements of § 75.21 of this chapter and appendix B to part 75 of this chapter, those CEMS may be used to meet the requirements of this section, provided that:

(1) When relative accuracy testing is conducted, $SO_2$ concentration data and $CO_2$ (or $O_2$) data are collected simultaneously; and

(2) In addition to meeting the applicable $SO_2$ and $CO_2$ (or $O_2$) relative accuracy specifications in Figure 2 of appendix B to part 75 of this chapter, the relative accuracy (RA) standard in section 13.2 of Performance Specification 2 in appendix B to this part is met when the RA is calculated on a lb/MMBtu basis; and

(3) The reporting requirements of § 60.49b are met. $SO_2$ and $CO_2$ (or $O_2$)

data used to meet the requirements of § 60.49b shall not include substitute data values derived from the missing data procedures in subpart D of part 75 of this chapter, nor shall the $SO_2$ data have been bias adjusted according to the procedures of part 75 of this chapter.

(b) As an alternative to operating CEMS as required under paragraph (a) of this section, an owner or operator may elect to determine the average $SO_2$ emissions and percent reduction by:

(1) Collecting coal or oil samples in an as-fired condition at the inlet to the steam generating unit and analyzing them for sulfur and heat content according to Method 19 of appendix A of this part. Method 19 of appendix A of this part provides procedures for converting these measurements into the format to be used in calculating the average $SO_2$ input rate, or

(2) Measuring $SO_2$ according to Method 6B of appendix A of this part at the inlet or outlet to the $SO_2$ control system. An initial stratification test is required to verify the adequacy of the Method 6B of appendix A of this part sampling location. The stratification test shall consist of three paired runs of a suitable $SO_2$ and $CO_2$ measurement train operated at the candidate location and a second similar train operated according to the procedures in section 3.2 and the applicable procedures in section 7 of Performance Specification 2. Method 6B of appendix A of this part, Method 6A of appendix A of this part, or a combination of Methods 6 and 3 or 3B of appendix A of this part or Methods 6C and 3A of appendix A of this part are suitable measurement techniques. If Method 6B of appendix A of this part is used for the second train, sampling time and timer operation may be adjusted for the stratification test as long as an adequate sample volume is collected; however, both sampling trains are to be operated similarly. For the location to be adequate for Method 6B of appendix A of this part 24-hour tests, the mean of the absolute difference between the three paired runs must be less than 10 percent.

(3) A daily $SO_2$ emission rate, $E_D$, shall be determined using the procedure described in Method 6A of appendix A of this part, section 7.6.2 (Equation 6A–8) and stated in ng/J (lb/MMBtu) heat input.

(4) The mean 30-day emission rate is calculated using the daily measured values in ng/J (lb/MMBtu) for 30 successive steam generating unit operating days using equation 19–20 of Method 19 of appendix A of this part.

(c) The owner or operator of an affected facility shall obtain emission data for at least 75 percent of the operating hours in at least 22 out of 30 successive boiler operating days. If this minimum data requirement is not met with a single monitoring system, the owner or operator of the affected facility shall supplement the emission data with data collected with other monitoring systems as approved by the Administrator or the reference methods and procedures as described in paragraph (b) of this section.

(d) The 1-hour average $SO_2$ emission rates measured by the CEMS required by paragraph (a) of this section and required under § 60.13(h) is expressed in ng/J or lb/MMBtu heat input and is used to calculate the average emission rates under § 60.42(b). Each 1-hour average $SO_2$ emission rate must be based on 30 or more minutes of steam generating unit operation. The hourly averages shall be calculated according to § 60.13(h)(2). Hourly $SO_2$ emission rates are not calculated if the affected facility is operated less than 30 minutes in a given clock hour and are not counted toward determination of a steam generating unit operating day.

(e) The procedures under § 60.13 shall be followed for installation, evaluation, and operation of the CEMS.

(1) Except as provided for in paragraph (e)(4) of this section, all CEMS shall be operated in accordance with the applicable procedures under Performance Specifications 1, 2, and 3 of appendix B of this part.

(2) Except as provided for in paragraph (e)(4) of this section, quarterly accuracy determinations and daily calibration drift tests shall be performed in accordance with Procedure 1 of appendix F of this part.

(3) For affected facilities combusting coal or oil, alone or in combination with other fuels, the span value of the $SO_2$ CEMS at the inlet to the $SO_2$ control device is 125 percent of the maximum estimated hourly potential $SO_2$ emissions of the fuel combusted, and the span value of the CEMS at the outlet to the $SO_2$ control device is 50 percent of the maximum estimated hourly potential $SO_2$ emissions of the fuel combusted. Alternatively, $SO_2$ span values determined according to section 2.1.1 in appendix A to part 75 of this chapter may be used.

(4) As an alternative to meeting the requirements of requirements of paragraphs (e)(1) and (e)(2) of this section, the owner or operator may elect to implement the following alternative data accuracy assessment procedures:

(i) For all required $CO_2$ and $O_2$ monitors and for $SO_2$ and $NO_X$ monitors with span values less than 100 ppm, the daily calibration error test and calibration adjustment procedures described in sections 2.1.1 and 2.1.3 of appendix B to part 75 of this chapter may be followed instead of the CD assessment procedures in Procedure 1, section 4.1 of appendix F to this part. If this option is selected, the data validation and out-of-control provisions in sections 2.1.4 and 2.1.5 of appendix B to part 75 of this chapter shall be followed instead of the excessive CD and out-of-control criteria in Procedure 1, section 4.3 of appendix F to this part. For the purposes of data validation under this subpart, the excessive CD and out-of-control criteria in Procedure 1, section 4.3 of appendix F to this part shall apply to $SO_2$ and $NO_X$ span values less than 100 ppm;

(ii) For all required $CO_2$ and $O_2$ monitors and for $SO_2$ and $NO_X$ monitors with span values greater than 30 ppm, quarterly linearity checks may be performed in accordance with section 2.2.1 of appendix B to part 75 of this chapter, instead of performing the cylinder gas audits (CGAs) described in Procedure 1, section 5.1.2 of appendix F to this part. If this option is selected: The frequency of the linearity checks shall be as specified in section 2.2.1 of appendix B to part 75 of this chapter; the applicable linearity specifications in section 3.2 of appendix A to part 75 of this chapter shall be met; the data validation and out-of-control criteria in section 2.2.3 of appendix B to part 75 of this chapter shall be followed instead of the excessive audit inaccuracy and out-of-control criteria in Procedure 1, section 5.2 of appendix F to this part; and the grace period provisions in section 2.2.4 of appendix B to part 75 of this chapter shall apply. For the purposes of data validation under this subpart, the cylinder gas audits described in Procedure 1, section 5.1.2 of appendix F to this part shall be performed for $SO_2$ and $NO_X$ span values less than or equal to 30 ppm; and

(iii) For $SO_2$, $CO_2$, and $O_2$ monitoring systems and for $NO_X$ emission rate monitoring systems, RATAs may be performed in accordance with section 2.3 of appendix B to part 75 of this chapter instead of following the procedures described in Procedure 1, section 5.1.1 of appendix F to this part. If this option is selected: The frequency of each RATA shall be as specified in section 2.3.1 of appendix B to part 75 of this chapter; the applicable relative accuracy specifications shown in Figure 2 in appendix B to part 75 of this chapter shall be met; the data validation and out-of-control criteria in section 2.3.2 of appendix B to part 75 of this chapter shall be followed instead of the excessive audit inaccuracy and out-of-control criteria in Procedure 1, section

5.2 of appendix F to this part; and the grace period provisions in section 2.3.3 of appendix B to part 75 of this chapter shall apply. For the purposes of data validation under this subpart, the relative accuracy specification in section 13.2 of Performance Specification 2 in appendix B to this part shall be met on a lb/MMBtu basis for $SO_2$ (regardless of the $SO_2$ emission level during the RATA), and for $NO_X$ when the average $NO_X$ emission rate measured by the reference method during the RATA is less than 0.100 lb/MMBtu.

(f) The owner or operator of an affected facility that combusts very low sulfur oil or is demonstrating compliance under § 60.45b(k) is not subject to the emission monitoring requirements under paragraph (a) of this section if the owner or operator maintains fuel records as described in § 60.49b(r).

**§ 60.48b Emission monitoring for particulate matter and nitrogen oxides.**

(a) Except as provided in paragraph (j) of this section, the owner or operator of an affected facility subject to the opacity standard under § 60.43b shall install, calibrate, maintain, and operate a CEMS for measuring the opacity of emissions discharged to the atmosphere and record the output of the system.

(b) Except as provided under paragraphs (g), (h), and (i) of this section, the owner or operator of an affected facility subject to a $NO_X$ standard under § 60.44b shall comply with either paragraphs (b)(1) or (b)(2) of this section.

(1) Install, calibrate, maintain, and operate CEMS for measuring $NO_X$ and $O_2$ (or $CO_2$) emissions discharged to the atmosphere, and shall record the output of the system; or

(2) If the owner or operator has installed a $NO_X$ emission rate CEMS to meet the requirements of part 75 of this chapter and is continuing to meet the ongoing requirements of part 75 of this chapter, that CEMS may be used to meet the requirements of this section, except that the owner or operator shall also meet the requirements of § 60.49b. Data reported to meet the requirements of § 60.49b shall not include data substituted using the missing data procedures in subpart D of part 75 of this chapter, nor shall the data have been bias adjusted according to the procedures of part 75 of this chapter.

(c) The CEMS required under paragraph (b) of this section shall be operated and data recorded during all periods of operation of the affected facility except for CEMS breakdowns and repairs. Data is recorded during calibration checks, and zero and span adjustments.

(d) The 1-hour average $NO_X$ emission rates measured by the continuous $NO_X$ monitor required by paragraph (b) of this section and required under § 60.13(h) shall be expressed in ng/J or lb/MMBtu heat input and shall be used to calculate the average emission rates under § 60.44b. The 1-hour averages shall be calculated using the data points required under § 60.13(h)(2).

(e) The procedures under § 60.13 shall be followed for installation, evaluation, and operation of the continuous monitoring systems.

(1) For affected facilities combusting coal, wood or municipal-type solid waste, the span value for a continuous monitoring system for measuring opacity shall be between 60 and 80 percent.

(2) For affected facilities combusting coal, oil, or natural gas, the span value for $NO_X$ is determined using one of the following procedures:

(i) Except as provided under paragraph (e)(2)(ii) of this section, $NO_X$ span values shall be determined as follows:

| Fuel | Span values for $NO_X$ (ppm) |
|---|---|
| Natural gas | 500. |
| Oil | 500. |
| Coal | 1,000. |
| Mixtures | 500 (x + y) + 1,000z. |

Where:

x = Fraction of total heat input derived from natural gas;

y = Fraction of total heat input derived from oil; and

z = Fraction of total heat input derived from coal.

(ii) As an alternative to meeting the requirements of paragraph (e)(2)(i) of this section, the owner or operator of an affected facility may elect to use the $NO_X$ span values determined according to section 2.1.2 in appendix A to part 75 of this chapter.

(3) All span values computed under paragraph (e)(2)(i) of this section for combusting mixtures of regulated fuels are rounded to the nearest 500 ppm. Span values computed under paragraph (e)(2)(ii) of this section shall be rounded off according to section 2.1.2 in appendix A to part 75 of this chapter.

(f) When $NO_X$ emission data are not obtained because of CEMS breakdowns, repairs, calibration checks and zero and span adjustments, emission data will be obtained by using standby monitoring systems, Method 7 of appendix A of this part, Method 7A of appendix A of this part, or other approved reference methods to provide emission data for a minimum of 75 percent of the operating hours in each steam generating unit operating day, in at least 22 out of 30 successive steam generating unit operating days.

(g) The owner or operator of an affected facility that has a heat input capacity of 73 MW (250 MMBtu/hr) or less, and that has an annual capacity factor for residual oil having a nitrogen content of 0.30 weight percent or less, natural gas, distillate oil, or any mixture of these fuels, greater than 10 percent (0.10) shall:

(1) Comply with the provisions of paragraphs (b), (c), (d), (e)(2), (e)(3), and (f) of this section; or

(2) Monitor steam generating unit operating conditions and predict $NO_X$ emission rates as specified in a plan submitted pursuant to § 60.49b(c).

(h) The owner or operator of a duct burner, as described in § 60.41b, that is subject to the $NO_X$ standards of § 60.44b(a)(4) or § 60.44b(l) is not required to install or operate a continuous emissions monitoring system to measure $NO_X$ emissions.

(i) The owner or operator of an affected facility described in § 60.44b(j) or § 60.44b(k) is not required to install or operate a CEMS for measuring $NO_X$ emissions.

(j) The owner or operator of an affected facility that meets the conditions in either paragraph (j)(1), (2), (3), (4), or (5) of this section is not required to install or operate a COMS for measuring opacity if:

(1) The affected facility uses a PM CEMS to monitor PM emissions; or

(2) The affected facility burns only liquid (excluding residual oil) or gaseous fuels with potential $SO_2$ emissions rates of 26 ng/J (0.060 lb/MMBtu) or less and does not use a post-combustion technology to reduce $SO_2$ or PM emissions. The owner or operator must maintain fuel records of the sulfur content of the fuels burned, as described under § 60.49b(r); or

(3) The affected facility burns coke oven gas alone or in combination with fuels meeting the criteria in paragraph (j)(2) of this section and does not use a post-combustion technology to reduce $SO_2$ or PM emissions; or

(4) The affected facility does not use post-combustion technology (except a wet scrubber) for reducing PM, $SO_2$, or carbon monoxide (CO) emissions, burns only gaseous fuels or fuel oils that contain less than or equal to 0.30 weight percent sulfur, and is operated such that emissions of CO to the atmosphere from the affected facility are maintained at levels less than or equal to 0.15 lb/MMBtu on a steam generating unit operating day average basis. Owners and

operators of affected facilities electing to comply with this paragraph must demonstrate compliance according to the procedures specified in paragraphs (j)(4)(i) through (iv) of this section.

(i) You must monitor CO emissions using a CEMS according to the procedures specified in paragraphs (j)(4)(i)(A) through (D) of this section.

(A) The CO CEMS must be installed, certified, maintained, and operated according to the provisions in § 60.58b(i)(3) of subpart Eb of this part.

(B) Each 1-hour CO emissions average is calculated using the data points generated by the CO CEMS expressed in parts per million by volume corrected to 3 percent oxygen (dry basis).

(C) At a minimum, valid 1-hour CO emissions averages must be obtained for at least 90 percent of the operating hours on a 30-day rolling average basis. At least two data points per hour must be used to calculate each 1-hour average.

(D) Quarterly accuracy determinations and daily calibration drift tests for the CO CEMS must be performed in accordance with procedure 1 in appendix F of this part.

(ii) You must calculate the 1-hour average CO emissions levels for each steam generating unit operating day by multiplying the average hourly CO output concentration measured by the CO CEMS times the corresponding average hourly flue gas flow rate and divided by the corresponding average hourly heat input to the affected source. The 24-hour average CO emission level is determined by calculating the arithmetic average of the hourly CO emission levels computed for each steam generating unit operating day.

(iii) You must evaluate the preceding 24-hour average CO emission level each steam generating unit operating day excluding periods of affected source startup, shutdown, or malfunction. If the 24-hour average CO emission level is greater than 0.15 lb/MMBtu, you must initiate investigation of the relevant equipment and control systems within 24 hours of the first discovery of the high emission incident and, take the appropriate corrective action as soon as practicable to adjust control settings or repair equipment to reduce the 24-hour average CO emission level to 0.15 lb/MMBtu or less.

(iv) You must record the CO measurements and calculations performed according to paragraph (j)(4) of this section and any corrective actions taken. The record of corrective action taken must include the date and time during which the 24-hour average CO emission level was greater than 0.15 lb/MMBtu, and the date, time, and description of the corrective action.

(5) The affected facility burns only gaseous fuels or fuel oils that contain less than or equal to 0.30 weight percent sulfur and operates according to a written site-specific monitoring plan approved by the appropriate delegated 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.

(k) Owners or operators complying with the PM emission limit by using a PM CEMS monitor instead of monitoring opacity must calibrate, maintain, and operate a CEMS, and record the output of the system, for PM emissions discharged to the atmosphere as specified in § 60.46b(j). The CEMS specified in paragraph § 60.46b(j) shall be operated and data recorded during all periods of operation of the affected facility except for CEMS breakdowns and repairs. Data is recorded during calibration checks, and zero and span adjustments.

**§ 60.49b Reporting and recordkeeping requirements.**

(a) The owner or operator of each affected facility shall submit notification of the date of initial startup, as provided by § 60.7. This notification shall include:

(1) The design heat input capacity of the affected facility and identification of the fuels to be combusted in the affected facility;

(2) If applicable, a copy of any federally enforceable requirement that limits the annual capacity factor for any fuel or mixture of fuels under §§ 60.42b(d)(1), 60.43b(a)(2), (a)(3)(iii), (c)(2)(ii), (d)(2)(iii), 60.44b(c), (d), (e), (i), (j), (k), 60.45b(d), (g), 60.46b(h), or 60.48b(i);

(3) The annual capacity factor at which the owner or operator anticipates operating the facility based on all fuels fired and based on each individual fuel fired; and

(4) Notification that an emerging technology will be used for controlling emissions of $SO_2$. The Administrator will examine the description of the emerging technology and will determine whether the technology qualifies as an emerging technology. In making this determination, the Administrator may require the owner or operator of the affected facility to submit additional information concerning the control device. The affected facility is subject to the provisions of § 60.42b(a) unless and until this determination is made by the Administrator.

(b) The owner or operator of each affected facility subject to the $SO_2$, PM, and/or $NO_X$ emission limits under §§ 60.42b, 60.43b, and 60.44b shall submit to the Administrator the performance test data from the initial performance test and the performance evaluation of the CEMS using the applicable performance specifications in appendix B of this part. The owner or operator of each affected facility described in § 60.44b(j) or § 60.44b(k) shall submit to the Administrator the maximum heat input capacity data from the demonstration of the maximum heat input capacity of the affected facility.

(c) The owner or operator of each affected facility subject to the $NO_X$ standard of § 60.44b who seeks to demonstrate compliance with those standards through the monitoring of steam generating unit operating conditions under the provisions of § 60.48b(g)(2) shall submit to the Administrator for approval a plan that identifies the operating conditions to be monitored under § 60.48b(g)(2) and the records to be maintained under § 60.49b(j). This plan shall be submitted to the Administrator for approval within 360 days of the initial startup of the affected facility. If the plan is approved, the owner or operator shall maintain records of predicted nitrogen oxide emission rates and the monitored operating conditions, including steam generating unit load, identified in the plan. The plan shall:

(1) Identify the specific operating conditions to be monitored and the relationship between these operating conditions and $NO_X$ emission rates (*i.e.*, ng/J or lbs/MMBtu heat input). Steam generating unit operating conditions include, but are not limited to, the degree of staged combustion (*i.e.*, the ratio of primary air to secondary and/or tertiary air) and the level of excess air (*i.e.*, flue gas $O_2$ level);

(2) Include the data and information that the owner or operator used to identify the relationship between $NO_X$ emission rates and these operating conditions; and

(3) Identify how these operating conditions, including steam generating unit load, will be monitored under § 60.48b(g) on an hourly basis by the owner or operator during the period of operation of the affected facility; the quality assurance procedures or practices that will be employed to ensure that the data generated by monitoring these operating conditions will be representative and accurate; and the type and format of the records of these operating conditions, including steam generating unit load, that will be

maintained by the owner or operator under § 60.49b(j).

(d) The owner or operator of an affected facility shall record and maintain records of the amounts of each fuel combusted during each day and calculate the annual capacity factor individually for coal, distillate oil, residual oil, natural gas, wood, and municipal-type solid waste for the reporting period. The annual capacity factor is determined on a 12-month rolling average basis with a new annual capacity factor calculated at the end of each calendar month.

(e) For an affected facility that combusts residual oil and meets the criteria under §§ 60.46b(e)(4), 60.44b(j), or (k), the owner or operator shall maintain records of the nitrogen content of the residual oil combusted in the affected facility and calculate the average fuel nitrogen content for the reporting period. The nitrogen content shall be determined using ASTM Method D4629 (incorporated by reference, see § 60.17), or fuel suppliers. If residual oil blends are being combusted, fuel nitrogen specifications may be prorated based on the ratio of residual oils of different nitrogen content in the fuel blend.

(f) For facilities subject to the opacity standard under § 60.43b, the owner or operator shall maintain records of opacity.

(g) Except as provided under paragraph (p) of this section, the owner or operator of an affected facility subject to the $NO_X$ standards under § 60.44b shall maintain records of the following information for each steam generating unit operating day:

(1) Calendar date;

(2) The average hourly $NO_X$ emission rates (expressed as $NO_2$) (ng/J or lb/MMBtu heat input) measured or predicted;

(3) The 30-day average $NO_X$ emission rates (ng/J or lb/MMBtu heat input) calculated at the end of each steam generating unit operating day from the measured or predicted hourly nitrogen oxide emission rates for the preceding 30 steam generating unit operating days;

(4) Identification of the steam generating unit operating days when the calculated 30-day average $NO_X$ emission rates are in excess of the $NO_X$ emissions standards under § 60.44b, with the reasons for such excess emissions as well as a description of corrective actions taken;

(5) Identification of the steam generating unit operating days for which pollutant data have not been obtained, including reasons for not obtaining sufficient data and a description of corrective actions taken;

(6) Identification of the times when emission data have been excluded from the calculation of average emission rates and the reasons for excluding data;

(7) Identification of "F" factor used for calculations, method of determination, and type of fuel combusted;

(8) Identification of the times when the pollutant concentration exceeded full span of the CEMS;

(9) Description of any modifications to the CEMS that could affect the ability of the CEMS to comply with Performance Specification 2 or 3; and

(10) Results of daily CEMS drift tests and quarterly accuracy assessments as required under appendix F, Procedure 1 of this part.

(h) The owner or operator of any affected facility in any category listed in paragraphs (h)(1) or (2) of this section is required to submit excess emission reports for any excess emissions that occurred during the reporting period.

(1) Any affected facility subject to the opacity standards under § 60.43b(e) or to the operating parameter monitoring requirements under § 60.13(i)(1).

(2) Any affected facility that is subject to the $NO_X$ standard of § 60.44b, and that:

(i) Combusts natural gas, distillate oil, or residual oil with a nitrogen content of 0.3 weight percent or less; or

(ii) Has a heat input capacity of 73 MW (250 MMBtu/hr) or less and is required to monitor $NO_X$ emissions on a continuous basis under § 60.48b(g)(1) or steam generating unit operating conditions under § 60.48b(g)(2).

(3) For the purpose of § 60.43b, excess emissions are defined as all 6-minute periods during which the average opacity exceeds the opacity standards under § 60.43b(f).

(4) For purposes of § 60.48b(g)(1), excess emissions are defined as any calculated 30-day rolling average $NO_X$ emission rate, as determined under § 60.46b(e), that exceeds the applicable emission limits in § 60.44b.

(i) The owner or operator of any affected facility subject to the continuous monitoring requirements for $NO_X$ under § 60.48(b) shall submit reports containing the information recorded under paragraph (g) of this section.

(j) The owner or operator of any affected facility subject to the $SO_2$ standards under § 60.42b shall submit reports.

(k) For each affected facility subject to the compliance and performance testing requirements of § 60.45b and the reporting requirement in paragraph (j) of this section, the following information shall be reported to the Administrator:

(1) Calendar dates covered in the reporting period;

(2) Each 30-day average $SO_2$ emission rate (ng/J or lb/MMBtu heat input) measured during the reporting period, ending with the last 30-day period; reasons for noncompliance with the emission standards; and a description of corrective actions taken;

(3) Each 30-day average percent reduction in $SO_2$ emissions calculated during the reporting period, ending with the last 30-day period; reasons for noncompliance with the emission standards; and a description of corrective actions taken;

(4) Identification of the steam generating unit operating days that coal or oil was combusted and for which $SO_2$ or diluent ($O_2$ or $CO_2$) data have not been obtained by an approved method for at least 75 percent of the operating hours in the steam generating unit operating day; justification for not obtaining sufficient data; and description of corrective action taken;

(5) Identification of the times when emissions data have been excluded from the calculation of average emission rates; justification for excluding data; and description of corrective action taken if data have been excluded for periods other than those during which coal or oil were not combusted in the steam generating unit;

(6) Identification of "F" factor used for calculations, method of determination, and type of fuel combusted;

(7) Identification of times when hourly averages have been obtained based on manual sampling methods;

(8) Identification of the times when the pollutant concentration exceeded full span of the CEMS;

(9) Description of any modifications to the CEMS that could affect the ability of the CEMS to comply with Performance Specification 2 or 3;

(10) Results of daily CEMS drift tests and quarterly accuracy assessments as required under appendix F, Procedure 1 of this part; and

(11) The annual capacity factor of each fired as provided under paragraph (d) of this section.

(l) For each affected facility subject to the compliance and performance testing requirements of § 60.45b(d) and the reporting requirements of paragraph (j) of this section, the following information shall be reported to the Administrator:

(1) Calendar dates when the facility was in operation during the reporting period;

(2) The 24-hour average $SO_2$ emission rate measured for each steam generating unit operating day during the reporting

period that coal or oil was combusted, ending in the last 24-hour period in the quarter; reasons for noncompliance with the emission standards; and a description of corrective actions taken;

(3) Identification of the steam generating unit operating days that coal or oil was combusted for which $SO_2$ or diluent ($O_2$ or $CO_2$) data have not been obtained by an approved method for at least 75 percent of the operating hours; justification for not obtaining sufficient data; and description of corrective action taken;

(4) Identification of the times when emissions data have been excluded from the calculation of average emission rates; justification for excluding data; and description of corrective action taken if data have been excluded for periods other than those during which coal or oil were not combusted in the steam generating unit;

(5) Identification of "F" factor used for calculations, method of determination, and type of fuel combusted;

(6) Identification of times when hourly averages have been obtained based on manual sampling methods;

(7) Identification of the times when the pollutant concentration exceeded full span of the CEMS;

(8) Description of any modifications to the CEMS that could affect the ability of the CEMS to comply with Performance Specification 2 or 3; and

(9) Results of daily CEMS drift tests and quarterly accuracy assessments as required under Procedure 1 of appendix F 1 of this part. If the owner or operator elects to implement the alternative data assessment procedures described in §§ 60.47b(e)(4)(i) through (e)(4)(iii), each data assessment report shall include a summary of the results of all of the RATAs, linearity checks, CGAs, and calibration error or drift assessments required by §§ 60.47b(e)(4)(i) through (e)(4)(iii).

(m) For each affected facility subject to the $SO_2$ standards under § 60.42(b) for which the minimum amount of data required under § 60.47b(f) were not obtained during the reporting period, the following information is reported to the Administrator in addition to that required under paragraph (k) of this section:

(1) The number of hourly averages available for outlet emission rates and inlet emission rates;

(2) The standard deviation of hourly averages for outlet emission rates and inlet emission rates, as determined in Method 19 of appendix A of this part, section 7;

(3) The lower confidence limit for the mean outlet emission rate and the upper confidence limit for the mean inlet emission rate, as calculated in Method 19 of appendix A of this part, section 7; and

(4) The ratio of the lower confidence limit for the mean outlet emission rate and the allowable emission rate, as determined in Method 19 of appendix A of this part, section 7.

(n) If a percent removal efficiency by fuel pretreatment (*i.e.*, $\%R_f$) is used to determine the overall percent reduction (*i.e.*, $\%R_o$) under § 60.45b, the owner or operator of the affected facility shall submit a signed statement with the report.

(1) Indicating what removal efficiency by fuel pretreatment (*i.e.*, $\%R_f$) was credited during the reporting period;

(2) Listing the quantity, heat content, and date each pre-treated fuel shipment was received during the reporting period, the name and location of the fuel pretreatment facility; and the total quantity and total heat content of all fuels received at the affected facility during the reporting period;

(3) Documenting the transport of the fuel from the fuel pretreatment facility to the steam generating unit; and

(4) Including a signed statement from the owner or operator of the fuel pretreatment facility certifying that the percent removal efficiency achieved by fuel pretreatment was determined in accordance with the provisions of Method 19 of appendix A of this part and listing the heat content and sulfur content of each fuel before and after fuel pretreatment.

(o) All records required under this section shall be maintained by the owner or operator of the affected facility for a period of 2 years following the date of such record.

(p) The owner or operator of an affected facility described in § 60.44b(j) or (k) shall maintain records of the following information for each steam generating unit operating day:

(1) Calendar date;

(2) The number of hours of operation; and

(3) A record of the hourly steam load.

(q) The owner or operator of an affected facility described in § 60.44b(j) or § 60.44b(k) shall submit to the Administrator a report containing:

(1) The annual capacity factor over the previous 12 months;

(2) The average fuel nitrogen content during the reporting period, if residual oil was fired; and

(3) If the affected facility meets the criteria described in § 60.44b(j), the results of any $NO_X$ emission tests required during the reporting period, the hours of operation during the reporting period, and the hours of operation since the last $NO_X$ emission test.

(r) The owner or operator of an affected facility who elects to use the fuel based compliance alternatives in § 60.42b or § 60.43b shall either:

(1) The owner or operator of an affected facility who elects to demonstrate that the affected facility combusts only very low sulfur oil under § 60.42b(j)(2) or § 60.42b(k)(2) shall obtain and maintain at the affected facility fuel receipts from the fuel supplier that certify that the oil meets the definition of distillate oil as defined in § 60.41b and the applicable sulfur limit. For the purposes of this section, the distillate oil need not meet the fuel nitrogen content specification in the definition of distillate oil. Reports shall be submitted to the Administrator certifying that only very low sulfur oil meeting this definition and/or pipeline quality natural gas was combusted in the affected facility during the reporting period; or

(2) The owner or operator of an affected facility who elects to demonstrate compliance based on fuel analysis in § 60.42b or § 60.43b shall develop and submit a site-specific fuel analysis plan to the Administrator for review and approval no later than 60 days before the date you intend to demonstrate compliance. Each fuel analysis plan shall include a minimum initial requirement of weekly testing and each analysis report shall contain, at a minimum, the following information:

(i) The potential sulfur emissions rate of the representative fuel mixture in ng/J heat input;

(ii) The method used to determine the potential sulfur emissions rate of each constituent of the mixture. For distillate oil and natural gas a fuel receipt or tariff sheet is acceptable;

(iii) The ratio of different fuels in the mixture; and

(iv) The owner or operator can petition the Administrator to approve monthly or quarterly sampling in place of weekly sampling.

(s) Facility specific $NO_X$ standard for Cytec Industries Fortier Plant's C.AOG incinerator located in Westwego, Louisiana:

(1) *Definitions.*

*Oxidation zone* is defined as the portion of the C.AOG incinerator that extends from the inlet of the oxidizing zone combustion air to the outlet gas stack.

*Reducing zone* is defined as the portion of the C.AOG incinerator that extends from the burner section to the inlet of the oxidizing zone combustion air.

*Total inlet air* is defined as the total amount of air introduced into the C.AOG incinerator for combustion of natural gas and chemical by-product waste and is equal to the sum of the air flow into the reducing zone and the air flow into the oxidation zone.

(2) *Standard for nitrogen oxides.* (i) When fossil fuel alone is combusted, the $NO_X$ emission limit for fossil fuel in § 60.44b(a) applies.

(ii) When natural gas and chemical by-product waste are simultaneously combusted, the $NO_X$ emission limit is 289 ng/J (0.67 lb/MMBtu) and a maximum of 81 percent of the total inlet air provided for combustion shall be provided to the reducing zone of the C.AOG incinerator.

(3) *Emission monitoring.* (i) The percent of total inlet air provided to the reducing zone shall be determined at least every 15 minutes by measuring the air flow of all the air entering the reducing zone and the air flow of all the air entering the oxidation zone, and compliance with the percentage of total inlet air that is provided to the reducing zone shall be determined on a 3-hour average basis.

(ii) The $NO_X$ emission limit shall be determined by the compliance and performance test methods and procedures for $NO_X$ in § 60.46b(i).

(iii) The monitoring of the $NO_X$ emission limit shall be performed in accordance with § 60.48b.

(4) *Reporting and recordkeeping requirements.* (i) The owner or operator of the C.AOG incinerator shall submit a report on any excursions from the limits required by paragraph (a)(2) of this section to the Administrator with the quarterly report required by paragraph (i) of this section.

(ii) The owner or operator of the C.AOG incinerator shall keep records of the monitoring required by paragraph (a)(3) of this section for a period of 2 years following the date of such record.

(iii) The owner of operator of the C.AOG incinerator shall perform all the applicable reporting and recordkeeping requirements of this section.

(t) Facility-specific $NO_X$ standard for Rohm and Haas Kentucky Incorporated's Boiler No. 100 located in Louisville, Kentucky:

(1) *Definitions.*

*Air ratio control damper* is defined as the part of the low $NO_X$ burner that is adjusted to control the split of total combustion air delivered to the reducing and oxidation portions of the combustion flame.

*Flue gas recirculation line* is defined as the part of Boiler No. 100 that recirculates a portion of the boiler flue gas back into the combustion air.

(2) *Standard for nitrogen oxides.* (i) When fossil fuel alone is combusted, the $NO_X$ emission limit for fossil fuel in § 60.44b(a) applies.

(ii) When fossil fuel and chemical by-product waste are simultaneously combusted, the $NO_X$ emission limit is 473 ng/J (1.1 lb/MMBtu), and the air ratio control damper tee handle shall be at a minimum of 5 inches (12.7 centimeters) out of the boiler, and the flue gas recirculation line shall be operated at a minimum of 10 percent open as indicated by its valve opening position indicator.

(3) *Emission monitoring for nitrogen oxides.* (i) The air ratio control damper tee handle setting and the flue gas recirculation line valve opening position indicator setting shall be recorded during each 8-hour operating shift.

(ii) The $NO_X$ emission limit shall be determined by the compliance and performance test methods and procedures for $NO_X$ in § 60.46b.

(iii) The monitoring of the $NO_X$ emission limit shall be performed in accordance with § 60.48b.

(4) *Reporting and recordkeeping requirements.* (i) The owner or operator of Boiler No. 100 shall submit a report on any excursions from the limits required by paragraph (b)(2) of this section to the Administrator with the quarterly report required by § 60.49b(i).

(ii) The owner or operator of Boiler No. 100 shall keep records of the monitoring required by paragraph (b)(3) of this section for a period of 2 years following the date of such record.

(iii) The owner of operator of Boiler No. 100 shall perform all the applicable reporting and recordkeeping requirements of § 60.49b.

(u) *Site-specific standard for Merck & Co., Inc.'s Stonewall Plant in Elkton, Virginia.* (1) This paragraph (u) applies only to the pharmaceutical manufacturing facility, commonly referred to as the Stonewall Plant, located at Route 340 South, in Elkton, Virginia ("site") and only to the natural gas-fired boilers installed as part of the powerhouse conversion required pursuant to 40 CFR 52.2454(g). The requirements of this paragraph shall apply, and the requirements of §§ 60.40b through 60.49b(t) shall not apply, to the natural gas-fired boilers installed pursuant to 40 CFR 52.2454(g).

(i) The site shall equip the natural gas-fired boilers with low $NO_X$ technology.

(ii) The site shall install, calibrate, maintain, and operate a continuous monitoring and recording system for measuring $NO_X$ emissions discharged to the atmosphere and opacity using a continuous emissions monitoring system or a predictive emissions monitoring system.

(iii) Within 180 days of the completion of the powerhouse conversion, as required by 40 CFR 52.2454, the site shall perform a performance test to quantify criteria pollutant emissions.

(2) [Reserved]

(v) The owner or operator of an affected facility may submit electronic quarterly reports for $SO_2$ and/or $NO_X$ and/or opacity in lieu of submitting the written reports required under paragraphs (h), (i), (j), (k) or (l) of this section. The format of each quarterly electronic report shall be coordinated with the permitting authority. The electronic report(s) shall be submitted no later than 30 days after the end of the calendar quarter and shall be accompanied by a certification statement from the owner or operator, indicating whether compliance with the applicable emission standards and minimum data requirements of this subpart was achieved during the reporting period. Before submitting reports in the electronic format, the owner or operator shall coordinate with the permitting authority to obtain their agreement to submit reports in this alternative format.

(w) The reporting period for the reports required under this subpart is each 6 month period. All reports shall be submitted to the Administrator and shall be postmarked by the 30th day following the end of the reporting period.

(x) Facility-specific $NO_X$ standard for Weyerhaeuser Company's No. 2 Power Boiler located in New Bern, North Carolina:

(1) *Standard for nitrogen oxides.* (i) When fossil fuel alone is combusted, the $NO_X$ emission limit for fossil fuel in § 60.44b(a) applies.

(ii) When fossil fuel and chemical by-product waste are simultaneously combusted, the $NO_X$ emission limit is 215 ng/J (0.5 lb/MMBtu).

(2) *Emission monitoring for nitrogen oxides.* (i) The $NO_X$ emissions shall be determined by the compliance and performance test methods and procedures for $NO_X$ in § 60.46b.

(ii) The monitoring of the $NO_X$ emissions shall be performed in accordance with § 60.48b.

(3) *Reporting and recordkeeping requirements.* (i) The owner or operator of the No. 2 Power Boiler shall submit a report on any excursions from the limits required by paragraph (x)(2) of this section to the Administrator with the quarterly report required by § 60.49b(i).

(ii) The owner or operator of the No. 2 Power Boiler shall keep records of the monitoring required by paragraph (x)(3) of this section for a period of 2 years following the date of such record.

(iii) The owner or operator of the No. 2 Power Boiler shall perform all the applicable reporting and recordkeeping requirements of § 60.49b.

(y) Facility-specific $NO_X$ standard for INEOS USA's AOGI located in Lima, Ohio:

(1) *Standard for $NO_X$.* (i) When fossil fuel alone is combusted, the $NO_X$ emission limit for fossil fuel in § 60.44b(a) applies.

(ii) When fossil fuel and chemical byproduct/waste are simultaneously combusted, the $NO_X$ emission limit is 645 ng/J (1.5 lb/MMBtu).

(2) *Emission monitoring for $NO_X$.* (i) The $NO_X$ emissions shall be determined by the compliance and performance test methods and procedures for $NO_X$ in § 60.46b.

(ii) The monitoring of the $NO_X$ emissions shall be performed in accordance with § 60.48b.

(3) *Reporting and recordkeeping requirements.* (i) The owner or operator of the AOGI shall submit a report on any excursions from the limits required by paragraph (y)(2) of this section to the Administrator with the quarterly report required by paragraph (i) of this section.

(ii) The owner or operator of the AOGI shall keep records of the monitoring required by paragraph (y)(3) of this section for a period of 2 years following the date of such record.

(iii) The owner or operator of the AOGI shall perform all the applicable reporting and recordkeeping requirements of this section.

## Subpart Dc—[Amended]

■ 6. Subpart Dc is revised to read as follows:

### Subpart Dc—Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units

Sec.



### Subpart Dc—Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units

#### § 60.40c Applicability and delegation of authority.

(a) Except as provided in paragraph (d) of this section, the affected facility to which this subpart applies is each steam generating unit for which construction, modification, or reconstruction is commenced after June 9, 1989 and that has a maximum design heat input capacity of 29 megawatts (MW) (100 million British thermal units per hour (MMBtu/hr)) or less, but greater than or equal to 2.9 MW (10 MMBtu/hr).

(b) In delegating implementation and enforcement authority to a State under section 111(c) of the Clean Air Act, § 60.48c(a)(4) shall be retained by the Administrator and not transferred to a State.

(c) Steam generating units that meet the applicability requirements in paragraph (a) of this section are not subject to the sulfur dioxide ($SO_2$) or particulate matter (PM) emission limits, performance testing requirements, or monitoring requirements under this subpart (§§ 60.42c, 60.43c, 60.44c, 60.45c, 60.46c, or 60.47c) during periods of combustion research, as defined in § 60.41c.

(d) Any temporary change to an existing steam generating unit for the purpose of conducting combustion research is not considered a modification under § 60.14.

(e) Heat recovery steam generators that are associated with combined cycle gas turbines and meet the applicability requirements of subpart GG or KKKK of this part are not subject to this subpart. This subpart will continue to apply to all other heat recovery steam generators that are capable of combusting more than or equal to 2.9 MW (10 MMBtu/hr) heat input of fossil fuel but less than or equal to 29 MW (100 MMBtu/hr) heat input of fossil fuel. If the heat recovery steam generator is subject to this subpart, only emissions resulting from combustion of fuels in the steam generating unit are subject to this subpart. (The gas turbine emissions are subject to subpart GG or KKKK, as applicable, of this part).

(f) Any facility covered by subpart AAAA of this part is not covered by this subpart.

(g) Any facility covered by an EPA approved State or Federal section 111(d)/129 plan implementing subpart BBBB of this part is not covered by this subpart.

#### § 60.41c Definitions.

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

*Annual capacity factor* means the ratio between the actual heat input to a steam generating unit from an individual fuel or combination of fuels during a period of 12 consecutive calendar months and the potential heat input to the steam generating unit from all fuels had the steam generating unit been operated for 8,760 hours during that 12-month period at the maximum design heat input capacity. In the case of steam generating units that are rented or leased, the actual heat input shall be determined based on the combined heat input from all operations of the affected facility during a period of 12 consecutive calendar months.

*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), coal refuse, and petroleum coke. Coal-derived synthetic fuels derived from coal for the purposes of creating useful heat, including but not limited to solvent refined coal, gasified coal, coal-oil mixtures, and coal-water mixtures, are also included in this definition for the purposes of this subpart.

*Coal refuse* means any by-product of coal mining or coal cleaning operations with an ash content greater than 50 percent (by weight) and a heating value less than 13,900 kilojoules per kilogram (kJ/kg) (6,000 Btu per pound (Btu/lb) on a dry basis.

*Cogeneration steam generating unit* means a steam generating unit that simultaneously produces both electrical (or mechanical) and thermal energy from the same primary energy source.

*Combined cycle system* means a system in which a separate source (such as a stationary gas turbine, internal combustion engine, or kiln) provides exhaust gas to a steam generating unit.

*Combustion research* means the experimental firing of any fuel or combination of fuels in a steam generating unit for the purpose of conducting research and development of more efficient combustion or more effective prevention or control of air pollutant emissions from combustion, provided that, during these periods of research and development, the heat generated is not used for any purpose other than preheating combustion air for use by that steam generating unit (*i.e.*, the heat generated is released to the atmosphere without being used for space heating, process heating, driving pumps, preheating combustion air for

other units, generating electricity, or any other purpose).

*Conventional technology* means wet flue gas desulfurization technology, dry flue gas desulfurization technology, atmospheric fluidized bed combustion technology, and oil hydrodesulfurization technology.

*Distillate oil* means fuel oil that complies with the specifications for fuel oil numbers 1 or 2, as defined by the American Society for Testing and Materials in ASTM D396 (incorporated by reference, see § 60.17).

*Dry flue gas desulfurization technology* means a $SO_2$ control system that is located between the steam generating unit and the exhaust vent or stack, and that removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gases with an alkaline reagent and water, whether introduced separately or as a premixed slurry or solution and forming a dry powder material. This definition includes devices where the dry powder material is subsequently converted to another form. Alkaline reagents used in dry flue gas desulfurization systems include, but are not limited to, lime and sodium compounds.

*Duct burner* means a device that combusts fuel and that is placed in the exhaust duct from another source (such as a stationary gas turbine, internal combustion engine, kiln, etc.) to allow the firing of additional fuel to heat the exhaust gases before the exhaust gases enter a steam generating unit.

*Emerging technology* means any $SO_2$ control system that is not defined as a conventional technology under this section, and for which the owner or operator of the affected facility has received approval from the Administrator to operate as an emerging technology under § 60.48c(a)(4).

*Federally enforceable* means all limitations and conditions that are enforceable by the Administrator, including the requirements of 40 CFR parts 60 and 61, requirements within any applicable State implementation plan, and any permit requirements established under 40 CFR 52.21 or under 40 CFR 51.18 and 51.24.

*Fluidized bed combustion technology* means a device wherein fuel is distributed onto a bed (or series of beds) of limestone aggregate (or other sorbent materials) for combustion; and these materials are forced upward in the device by the flow of combustion air and the gaseous products of combustion. Fluidized bed combustion technology includes, but is not limited to, bubbling bed units and circulating bed units.

*Fuel pretreatment* means a process that removes a portion of the sulfur in a fuel before combustion of the fuel in a steam generating unit.

*Heat input* means heat derived from combustion of fuel in a steam generating unit and does not include the heat derived from preheated combustion air, recirculated flue gases, or exhaust gases from other sources (such as stationary gas turbines, internal combustion engines, and kilns).

*Heat transfer medium* means any material that is used to transfer heat from one point to another point.

*Maximum design heat input capacity* means the ability of a steam generating unit to combust a stated maximum amount of fuel (or combination of fuels) on a steady state basis as determined by the physical design and characteristics of the steam generating unit.

*Natural gas* means: (1) A naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane; or (2) liquefied petroleum (LP) gas, as defined by the American Society for Testing and Materials in ASTM D1835 (incorporated by reference, see § 60.17).

*Noncontinental area* means the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, or the Northern Mariana Islands.

*Oil* means crude oil or petroleum, or a liquid fuel derived from crude oil or petroleum, including distillate oil and residual oil.

*Potential sulfur dioxide emission rate* means the theoretical $SO_2$ emissions (nanograms per joule (ng/J) or lb/MMBtu heat input) that would result from combusting fuel in an uncleaned state and without using emission control systems.

*Process heater* means a device that is primarily used to heat a material to initiate or promote a chemical reaction in which the material participates as a reactant or catalyst.

*Residual oil* means crude oil, fuel oil that does not comply with the specifications under the definition of distillate oil, and all fuel oil numbers 4, 5, and 6, as defined by the American Society for Testing and Materials in ASTM D396 (incorporated by reference, see § 60.17).

*Steam generating unit* means a device that combusts any fuel and produces steam or heats water or any other heat transfer medium. This term includes any duct burner that combusts fuel and is part of a combined cycle system. This term does not include process heaters as defined in this subpart.

*Steam generating unit operating day* means a 24-hour period between 12:00 midnight and the following midnight during which any fuel is combusted at any time in the steam generating unit. It is not necessary for fuel to be combusted continuously for the entire 24-hour period.

*Wet flue gas desulfurization technology* means an $SO_2$ control system that is located between the steam generating unit and the exhaust vent or stack, and that removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gases with an alkaline slurry or solution and forming a liquid material. This definition includes devices where the liquid material is subsequently converted to another form. Alkaline reagents used in wet flue gas desulfurization systems include, but are not limited to, lime, limestone, and sodium compounds.

*Wet scrubber system* means any emission control device that mixes an aqueous stream or slurry with the exhaust gases from a steam generating unit to control emissions of PM or $SO_2$.

*Wood* means wood, wood residue, bark, or any derivative fuel or residue thereof, in any form, including but not limited to sawdust, sanderdust, wood chips, scraps, slabs, millings, shavings, and processed pellets made from wood or other forest residues.

### § 60.42c Standard for sulfur dioxide ($SO_2$).

(a) Except as provided in paragraphs (b), (c), and (e) of this section, on and after the date on which the performance test is completed or required to be completed under § 60.8, whichever date comes first, the owner or operator of an affected facility that combusts only coal shall neither: cause to be discharged into the atmosphere from the affected facility any gases that contain $SO_2$ in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 10 percent (0.10) of the potential $SO_2$ emission rate (90 percent reduction), nor cause to be discharged into the atmosphere from the affected facility any gases that contain $SO_2$ in excess of 520 ng/J (1.2 lb/MMBtu) heat input. If coal is combusted with other fuels, the affected facility shall neither: cause to be discharged into the atmosphere from the affected facility any gases that contain $SO_2$ in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 10 percent (0.10) of the potential $SO_2$ emission rate (90 percent reduction), nor cause to be discharged into the atmosphere from the affected facility any gases that contain $SO_2$ in excess of the emission limit is determined pursuant to paragraph (e)(2) of this section.

(b) Except as provided in paragraphs (c) and (e) of this section, on and after the date on which the performance test is completed or required to be completed under § 60.8, whichever date comes first, the owner or operator of an affected facility that:

(1) Combusts only coal refuse alone in a fluidized bed combustion steam generating unit shall neither:

(i) Cause to be discharged into the atmosphere from that affected facility any gases that contain $SO_2$ in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 20 percent (0.20) of the potential $SO_2$ emission rate (80 percent reduction); nor

(ii) Cause to be discharged into the atmosphere from that affected facility any gases that contain $SO_2$ in excess of $SO_2$ in excess of 520 ng/J (1.2 lb/MMBtu) heat input. If coal is fired with coal refuse, the affected facility subject to paragraph (a) of this section. If oil or any other fuel (except coal) is fired with coal refuse, the affected facility is subject to the 87 ng/J (0.20 lb/MMBtu) heat input $SO_2$ emissions limit or the 90 percent $SO_2$ reduction requirement specified in paragraph (a) of this section and the emission limit is determined pursuant to paragraph (e)(2) of this section.

(2) Combusts only coal and that uses an emerging technology for the control of $SO_2$ emissions shall neither:

(i) Cause to be discharged into the atmosphere from that affected facility any gases that contain $SO_2$ in excess of 50 percent (0.50) of the potential $SO_2$ emission rate (50 percent reduction); nor

(ii) Cause to be discharged into the atmosphere from that affected facility any gases that contain $SO_2$ in excess of 260 ng/J (0.60 lb/MMBtu) heat input. If coal is combusted with other fuels, the affected facility is subject to the 50 percent $SO_2$ reduction requirement specified in this paragraph and the emission limit determined pursuant to paragraph (e)(2) of this section.

(c) 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, no owner or operator of an affected facility that combusts coal, alone or in combination with any other fuel, and is listed in paragraphs (c)(1), (2), (3), or (4) of this section shall cause to be discharged into the atmosphere from that affected facility any gases that contain $SO_2$ in excess of the emission limit determined pursuant to paragraph (e)(2) of this section. Percent reduction requirements are not applicable to affected facilities under paragraphs (c)(1), (2), (3), or (4).

(1) Affected facilities that have a heat input capacity of 22 MW (75 MMBtu/hr) or less.

(2) Affected facilities that have an annual capacity for coal of 55 percent (0.55) or less and are subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor for coal of 55 percent (0.55) or less.

(3) Affected facilities located in a noncontinental area.

(4) Affected facilities that combust coal in a duct burner as part of a combined cycle system where 30 percent (0.30) or less of the heat entering the steam generating unit is from combustion of coal in the duct burner and 70 percent (0.70) or more of the heat entering the steam generating unit is from exhaust gases entering the duct burner.

(d) 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, no owner or operator of an affected facility that combusts oil shall cause to be discharged into the atmosphere from that affected facility any gases that contain $SO_2$ in excess of 215 ng/J (0.50 lb/MMBtu) heat input; or, as an alternative, no owner or operator of an affected facility that combusts oil shall combust oil in the affected facility that contains greater than 0.5 weight percent sulfur. The percent reduction requirements are not applicable to affected facilities under this paragraph.

(e) 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, no owner or operator of an affected facility that combusts coal, oil, or coal and oil with any other fuel shall cause to be discharged into the atmosphere from that affected facility any gases that contain $SO_2$ in excess of the following:

(1) The percent of potential $SO_2$ emission rate or numerical $SO_2$ emission rate required under paragraph (a) or (b)(2) of this section, as applicable, for any affected facility that

(i) Combusts coal in combination with any other fuel;

(ii) Has a heat input capacity greater than 22 MW (75 MMBtu/hr); and

(iii) Has an annual capacity factor for coal greater than 55 percent (0.55); and

(2) The emission limit determined according to the following formula for any affected facility that combusts coal, oil, or coal and oil with any other fuel:

$$E_s = \frac{(K_a H_a + K_b H_b + K_c H_c)}{(H_a + H_b + H_c)}$$

Where:

$E_s$ = $SO_2$ emission limit, expressed in ng/J or lb/MMBtu heat input;

$K_a$ = 520 ng/J (1.2 lb/MMBtu);

$K_b$ = 260 ng/J (0.60 lb/MMBtu);

$K_c$ = 215 ng/J (0.50 lb/MMBtu);

$H_a$ = Heat input from the combustion of coal, except coal combusted in an affected facility subject to paragraph (b)(2) of this section, in Joules (J) [MMBtu];

$H_b$ = Heat input from the combustion of coal in an affected facility subject to paragraph (b)(2) of this section, in J (MMBtu); and

$H_c$ $K_a H_b$ = Heat input from the combustion of oil, in J (MMBtu).

(f) Reduction in the potential $SO_2$ emission rate through fuel pretreatment is not credited toward the percent reduction requirement under paragraph (b)(2) of this section unless:

(1) Fuel pretreatment results in a 50 percent (0.50) or greater reduction in the potential $SO_2$ emission rate; and

(2) Emissions from the pretreated fuel (without either combustion or post-combustion $SO_2$ control) are equal to or less than the emission limits specified under paragraph (b)(2) of this section.

(g) Except as provided in paragraph (h) of this section, compliance with the percent reduction requirements, fuel oil sulfur limits, and emission limits of this section shall be determined on a 30-day rolling average basis.

(h) For affected facilities listed under paragraphs (h)(1), (2), or (3) of this section, compliance with the emission limits or fuel oil sulfur limits under this section may be determined based on a certification from the fuel supplier, as described under § 60.48c(f), as applicable.

(1) Distillate oil-fired affected facilities with heat input capacities between 2.9 and 29 MW (10 and 100 MMBtu/hr).

(2) Residual oil-fired affected facilities with heat input capacities between 2.9 and 8.7 MW (10 and 30 MMBtu/hr).

(3) Coal-fired facilities with heat input capacities between 2.9 and 8.7 MW (10 and 30 MMBtu/hr).

(i) The $SO_2$ emission limits, fuel oil sulfur limits, and percent reduction requirements under this section apply at all times, including periods of startup, shutdown, and malfunction.

(j) Only the heat input supplied to the affected facility from the combustion of coal and oil is counted under this section. No credit is provided for the heat input to the affected facility from wood or other fuels or for heat derived from exhaust gases from other sources, such as stationary gas turbines, internal combustion engines, and kilns.

**§ 60.43c Standard for particulate matter (PM).**

(a) 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, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, that combusts coal or combusts mixtures of coal with other fuels and has a heat input capacity of 8.7 MW (30 MMBtu/hr) or greater, shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of the following emission limits:

(1) 22 ng/J (0.051 lb/MMBtu) heat input if the affected facility combusts only coal, or combusts coal with other fuels and has an annual capacity factor for the other fuels of 10 percent (0.10) or less.

(2) 43 ng/J (0.10 lb/MMBtu) heat input if the affected facility combusts coal with other fuels, has an annual capacity factor for the other fuels greater than 10 percent (0.10), and is subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor greater than 10 percent (0.10) for fuels other than coal.

(b) 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, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, that combusts wood or combusts mixtures of wood with other fuels (except coal) and has a heat input capacity of 8.7 MW (30 MMBtu/hr) or greater, shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of the following emissions limits:

(1) 43 ng/J (0.10 lb/MMBtu) heat input if the affected facility has an annual capacity factor for wood greater than 30 percent (0.30); or

(2) 130 ng/J (0.30 lb/MMBtu) heat input if the affected facility has an annual capacity factor for wood of 30 percent (0.30) or less and is subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor for wood of 30 percent (0.30) or less.

(c) 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, no owner or operator of an affected facility that combusts coal, wood, or oil and has a heat input capacity of 8.7 MW (30 MMBtu/hr) or greater shall cause to be discharged into the atmosphere from that affected facility any gases that exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity.

(d) The PM and opacity standards under this section apply at all times, except during periods of startup, shutdown, or malfunction.

(e)(1) On and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commences construction, reconstruction, or modification after February 28, 2005, and that combusts coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels and has a heat input capacity of 8.7 MW (30 MMBtu/hr) or greater shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 13 ng/J (0.030 lb/MMBtu) heat input, except as provided in paragraphs (e)(2), (e)(3), and (e)(4) of this section.

(2) As an alternative to meeting the requirements of paragraph (e)(1) of this section, the owner or operator of an affected facility for which modification commenced after February 28, 2005, may elect to meet the requirements of this paragraph. 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, no owner or operator of an affected facility that commences modification after February 28, 2005 shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of both:

(i) 22 ng/J (0.051 lb/MMBtu) heat input derived from the combustion of coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels; and

(ii) 0.2 percent of the combustion concentration (99.8 percent reduction) when combusting coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels.

(3) On and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, no owner or operator of an affected facility that commences modification after February 28, 2005, and that combusts over 30 percent wood (by heat input) on an annual basis and has a heat input capacity of 8.7 MW (30 MMBtu/hr) or greater shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 43 ng/J (0.10 lb/MMBtu) heat input.

(4) On and after the date on which the initial performance test is completed or is required to be completed under § 60.8, whichever date comes first, an owner or operator of an affected facility that commences construction, reconstruction, or modification after February 28, 2005, and that combusts only oil that contains no more than 0.50 weight percent sulfur or a mixture of 0.50 weight percent sulfur oil with other fuels not subject to a PM standard under § 60.43c and not using a post-combustion technology (except a wet scrubber) to reduce PM or $SO_2$ emissions is not subject to the PM limit in this section.

**§ 60.44c Compliance and performance test methods and procedures for sulfur dioxide.**

(a) Except as provided in paragraphs (g) and (h) of this section and § 60.8(b), performance tests required under § 60.8 shall be conducted following the procedures specified in paragraphs (b), (c), (d), (e), and (f) of this section, as applicable. Section 60.8(f) does not apply to this section. The 30-day notice required in § 60.8(d) applies only to the initial performance test unless otherwise specified by the Administrator.

(b) The initial performance test required under § 60.8 shall be conducted over 30 consecutive operating days of the steam generating unit. Compliance with the percent reduction requirements and $SO_2$ emission limits under § 60.42c shall be determined using a 30-day average. The first operating day included in the initial performance test shall be scheduled within 30 days after achieving the maximum production rate at which the affect facility will be operated, but not later than 180 days after the initial startup of the facility. The steam generating unit load during the 30-day period does not have to be the maximum design heat input capacity, but must be representative of future operating conditions.

(c) After the initial performance test required under paragraph (b) of this section and § 60.8, compliance with the percent reduction requirements and $SO_2$ emission limits under § 60.42c is based on the average percent reduction and the average $SO_2$ emission rates for 30 consecutive steam generating unit operating days. A separate performance test is completed at the end of each steam generating unit operating day, and a new 30-day average percent reduction and $SO_2$ emission rate are calculated to show compliance with the standard.

(d) If only coal, only oil, or a mixture of coal and oil is combusted in an

affected facility, the procedures in Method 19 of appendix A of this part are used to determine the hourly $SO_2$ emission rate ($E_{ho}$) and the 30-day average $SO_2$ emission rate ($E_{ao}$). The hourly averages used to compute the 30-day averages are obtained from the CEMS. Method 19 of appendix A of this part shall be used to calculate $E_{ao}$ when using daily fuel sampling or Method 6B of appendix A of this part.

(e) If coal, oil, or coal and oil are combusted with other fuels:

(1) An adjusted $E_{ho}$ ($E_{ho}o$) is used in Equation 19–19 of Method 19 of appendix A of this part to compute the adjusted $E_{ao}$ ($E_{ao}o$). The $E_{ho}o$ is computed using the following formula:

$$E_{ho}o = \frac{E_{ho} - E_w(1 - X_k)}{X_k}$$

Where:

$E_{ho}o$ = Adjusted $E_{ho}$, ng/J (lb/MMBtu);

$E_{ho}$ = Hourly $SO_2$ emission rate, ng/J (lb/MMBtu);

$E_w$ = $SO_2$ concentration in fuels other than coal and oil combusted in the affected facility, as determined by fuel sampling and analysis procedures in Method 9 of appendix A of this part, ng/J (lb/MMBtu). The value $E_w$ for each fuel lot is used for each hourly average during the time that the lot is being combusted. The owner or operator does not have to measure $E_w$ if the owner or operator elects to assume $E_w = 0$.

$X_k$ = Fraction of the total heat input from fuel combustion derived from coal and oil, as determined by applicable procedures in Method 19 of appendix A of this part.

(2) The owner or operator of an affected facility that qualifies under the provisions of § 60.42c(c) or (d) (where percent reduction is not required) does not have to measure the parameters $E_w$ or $X_k$ if the owner or operator of the affected facility elects to measure emission rates of the coal or oil using the fuel sampling and analysis procedures under Method 19 of appendix A of this part.

(f) Affected facilities subject to the percent reduction requirements under § 60.42c(a) or (b) shall determine compliance with the $SO_2$ emission limits under § 60.42c pursuant to paragraphs (d) or (e) of this section, and shall determine compliance with the percent reduction requirements using the following procedures:

(1) If only coal is combusted, the percent of potential $SO_2$ emission rate is computed using the following formula:

$$\%P_s = 100\left(1 - \frac{\%R_g}{100}\right)\left(1 - \frac{\%R_f}{100}\right)$$

Where:

$\%P_s$ = Potential $SO_2$ emission rate, in percent;

$\%R_g$ = $SO_2$ removal efficiency of the control device as determined by Method 19 of appendix A of this part, in percent; and

$\%R_f$ = $SO_2$ removal efficiency of fuel pretreatment as determined by Method 19 of appendix A of this part, in percent.

(2) If coal, oil, or coal and oil are combusted with other fuels, the same procedures required in paragraph (f)(1) of this section are used, except as provided for in the following:

(i) To compute the $\%P_s$, an adjusted $\%R_g$ ($\%R_g o$) is computed from $E_{ao}o$ from paragraph (e)(1) of this section and an adjusted average $SO_2$ inlet rate ($E_{ai}o$) using the following formula:

$$\%R_g o = 100\left(1 - \frac{E^o_{ao}}{E^o_{ai}}\right)$$

Where:

$\%R_g o$ = Adjusted $\%R_g$, in percent;

$E_{ao}o$ = Adjusted $E_{ao}$, ng/J (lb/MMBtu); and

$E_{ai}o$ = Adjusted average $SO_2$ inlet rate, ng/J (lb/MMBtu).

(ii) To compute $E_{ai}o$, an adjusted hourly $SO_2$ inlet rate ($E_{hi}o$) is used. The $E_{hi}o$ is computed using the following formula:

$$E_{hi}o = \frac{E_{hi} - E_w(1 - X_k)}{X_k}$$

Where:

$E_{hi}o$ = Adjusted $E_{hi}$, ng/J (lb/MMBtu);

$E_{hi}$ = Hourly $SO_2$ inlet rate, ng/J (lb/MMBtu);

$E_w$ = $SO_2$ concentration in fuels other than coal and oil combusted in the affected facility, as determined by fuel sampling and analysis procedures in Method 19 of appendix A of this part, ng/J (lb/MMBtu). The value $E_w$ for each fuel lot is used for each hourly average during the time that the lot is being combusted. The owner or operator does not have to measure $E_w$ if the owner or operator elects to assume $E_w = 0$; and

$X_k$ = Fraction of the total heat input from fuel combustion derived from coal and oil, as determined by applicable procedures in Method 19 of appendix A of this part.

(g) For oil-fired affected facilities where the owner or operator seeks to demonstrate compliance with the fuel oil sulfur limits under § 60.42c based on shipment fuel sampling, the initial performance test shall consist of sampling and analyzing the oil in the initial tank of oil to be fired in the steam generating unit to demonstrate that the oil contains 0.5 weight percent sulfur or less. Thereafter, the owner or operator of the affected facility shall sample the oil in the fuel tank after each new shipment of oil is received, as described under § 60.46c(d)(2).

(h) For affected facilities subject to § 60.42c(h)(1), (2), or (3) where the owner or operator seeks to demonstrate compliance with the $SO_2$ standards based on fuel supplier certification, the performance test shall consist of the certification, the certification from the fuel supplier, as described under § 60.48c(f), as applicable.

(i) The owner or operator of an affected facility seeking to demonstrate compliance with the $SO_2$ standards under § 60.42c(c)(2) shall demonstrate the maximum design heat input capacity of the steam generating unit by operating the steam generating unit at this capacity for 24 hours. This demonstration shall be made during the initial performance test, and a subsequent demonstration may be requested at any other time. If the demonstrated 24-hour average firing rate for the affected facility is less than the maximum design heat input capacity stated by the manufacturer of the affected facility, the demonstrated 24-hour average firing rate shall be used to determine the annual capacity factor for the affected facility; otherwise, the maximum design heat input capacity provided by the manufacturer shall be used.

(j) The owner or operator of an affected facility shall use all valid $SO_2$ emissions data in calculating $\%P_s$ and $E_{ho}$ under paragraphs (d), (e), or (f) of this section, as applicable, whether or not the minimum emissions data requirements under § 60.46c(f) are achieved. All valid emissions data, including valid data collected during periods of startup, shutdown, and malfunction, shall be used in calculating $\%P_s$ or $E_{ho}$ pursuant to paragraphs (d), (e), or (f) of this section, as applicable.

**§ 60.45c Compliance and performance test methods and procedures for particulate matter.**

(a) The owner or operator of an affected facility subject to the PM and/or opacity standards under § 60.43c shall conduct an initial performance test as required under § 60.8, and shall conduct subsequent performance tests as requested by the Administrator, to determine compliance with the standards using the following procedures and reference methods, except as specified in paragraph (c) of this section.

(1) Method 1 of appendix A of this part shall be used to select the sampling site and the number of traverse sampling points.

(2) Method 3 of appendix A of this part shall be used for gas analysis when applying Method 5, 5B, or 17 of appendix A of this part.

(3) Method 5, 5B, or 17 of appendix A of this part shall be used to measure the concentration of PM as follows:

(i) Method 5 of appendix A of this part may be used only at affected facilities without wet scrubber systems.

(ii) Method 17 of appendix A of this part may be used at affected facilities with or without wet scrubber systems provided the stack gas temperature does not exceed a temperature of 160 °C (320 °F). The procedures of Sections 8.1 and 11.1 of Method 5B of appendix A of this part may be used in Method 17 of appendix A of this part only if Method 17 of appendix A of this part is used in conjunction with a wet scrubber system. Method 17 of appendix A of this part shall not be used in conjunction with a wet scrubber system if the effluent is saturated or laden with water droplets.

(iii) Method 5B of appendix A of this part may be used in conjunction with a wet scrubber system.

(4) The sampling time for each run shall be at least 120 minutes and the minimum sampling volume shall be 1.7 dry standard cubic meters (dscm) [60 dry standard cubic feet (dscf)] except that smaller sampling times or volumes may be approved by the Administrator when necessitated by process variables or other factors.

(5) For Method 5 or 5B of appendix A of this part, the temperature of the sample gas in the probe and filter holder shall be monitored and maintained at 160 ±14 °C (320±25 °F).

(6) For determination of PM emissions, an oxygen ($O_2$) or carbon dioxide ($CO_2$) measurement shall be obtained simultaneously with each run of Method 5, 5B, or 17 of appendix A of this part by traversing the duct at the same sampling location.

(7) For each run using Method 5, 5B, or 17 of appendix A of this part, the emission rates expressed in ng/J (lb/MMBtu) heat input shall be determined using:

(i) The $O_2$ or $CO_2$ measurements and PM measurements obtained under this section, (ii) The dry basis F factor, and

(iii) The dry basis emission rate calculation procedure contained in Method 19 of appendix A of this part.

(8) Method 9 of appendix A of this part (6-minute average of 24 observations) shall be used for determining the opacity of stack emissions.

(b) The owner or operator of an affected facility seeking to demonstrate compliance with the PM standards under § 60.43c(b)(2) shall demonstrate the maximum design heat input capacity of the steam generating unit by operating the steam generating unit at this capacity for 24 hours. This demonstration shall be made during the initial performance test, and a subsequent demonstration may be requested at any other time. If the demonstrated 24-hour average firing rate for the affected facility is less than the maximum design heat input capacity stated by the manufacturer of the affected facility, the demonstrated 24-hour average firing rate shall be used to determine the annual capacity factor for the affected facility; otherwise, the maximum design heat input capacity provided by the manufacturer shall be used.

(c) In place of PM testing with EPA Reference Method 5, 5B, or 17 of appendix A of this part, an owner or operator may elect to install, calibrate, maintain, and operate a CEMS for monitoring PM emissions discharged to the atmosphere and record the output of the system. The owner or operator of an affected facility who elects to continuously monitor PM emissions instead of conducting performance testing using EPA Method 5, 5B, or 17 of appendix A of this part shall install, calibrate, maintain, and operate a CEMS and shall comply with the requirements specified in paragraphs (c)(1) through (c)(13) of this section.

(1) Notify the Administrator 1 month before starting use of the system.

(2) Notify the Administrator 1 month before stopping use of the system.

(3) The monitor shall be installed, evaluated, and operated in accordance with § 60.13 of subpart A of this part.

(4) The initial performance evaluation shall be completed no later than 180 days after the date of initial startup of the affected facility, as specified under § 60.8 of subpart A of this part or within 180 days of notification to the Administrator of use of CEMS if the owner or operator was previously determining compliance by Method 5, 5B, or 17 of appendix A of this part performance tests, whichever is later.

(5) The owner or operator of an affected facility shall conduct an initial performance test for PM emissions as required under § 60.8 of subpart A of this part. Compliance with the PM emission limit shall be determined by using the CEMS specified in paragraph (d) of this section to measure PM and calculating a 24-hour block arithmetic average emission concentration using EPA Reference Method 19 of appendix A of this part, section 4.1.

(6) Compliance with the PM emission limit shall be determined based on the 24-hour daily (block) average of the hourly arithmetic average emission concentrations using CEMS outlet data.

(7) At a minimum, valid CEMS hourly averages shall be obtained as specified in paragraph (d)(7)(i) of this section for 75 percent of the total operating hours per 30-day rolling average.

(i) At least two data points per hour shall be used to calculate each 1-hour arithmetic average.

(ii) [Reserved]

(8) The 1-hour arithmetic averages required under paragraph (d)(7) of this section shall be expressed in ng/J or lb/MMBtu heat input and shall be used to calculate the boiler operating day daily arithmetic average emission concentrations. The 1-hour arithmetic averages shall be calculated using the data points required under § 60.13(e)(2) of subpart A of this part.

(9) All valid CEMS data shall be used in calculating average emission concentrations even if the minimum CEMS data requirements of paragraph (d)(7) of this section are not met.

(10) The CEMS shall be operated according to Performance Specification 11 in appendix B of this part.

(11) During the correlation testing runs of the CEMS required by Performance Specification 11 in appendix B of this part, PM and $O_2$ (or $CO_2$) data shall be collected concurrently (or within a 30- to 60-minute period) by both the continuous emission monitors and the test methods specified in paragraph (d)(7)(i) of this section.

(i) For PM, EPA Reference Method 5, 5B, or 17 of appendix A of this part shall be used.

(ii) For $O_2$ (or $CO_2$), EPA reference Method 3, 3A, or 3B of appendix A of this part, as applicable shall be used.

(12) Quarterly accuracy determinations and daily calibration drift tests shall be performed in accordance with procedure 2 in appendix F of this part. Relative Response Audit's must be performed annually and Response Correlation Audits must be performed every 3 years.

(13) When PM emissions data are not obtained because of CEMS breakdowns, repairs, calibration checks, and zero and span adjustments, emissions data shall be obtained by using other monitoring systems as approved by the Administrator or EPA Reference Method 19 of appendix A of this part to provide, as necessary, valid emissions data for a minimum of 75 percent of total operating hours on a 30-day rolling average.

(d) The owner or operator of an affected facility seeking to demonstrate compliance under § 60.43c(e)(4) shall follow the applicable procedures under § 60.48c(f). For residual oil-fired affected facilities, fuel supplier certifications are only allowed for facilities with heat input capacities

between 2.9 and 8.7 MW (10 to 30 MMBtu/hr).

**§ 60.46c Emission monitoring for sulfur dioxide.**

(a) Except as provided in paragraphs (d) and (e) of this section, the owner or operator of an affected facility subject to the $SO_2$ emission limits under § 60.42c shall install, calibrate, maintain, and operate a CEMS for measuring $SO_2$ concentrations and either $O_2$ or $CO_2$ concentrations at the outlet of the $SO_2$ control device (or the outlet of the steam generating unit if no $SO_2$ control device is used), and shall record the output of the system. The owner or operator of an affected facility subject to the percent reduction requirements under § 60.42c shall measure $SO_2$ concentrations and either $O_2$ or $CO_2$ concentrations at both the inlet and outlet of the $SO_2$ control device.

(b) The 1-hour average $SO_2$ emission rates measured by a CEMS shall be expressed in ng/J or lb/MMBtu heat input and shall be used to calculate the average emission rates under § 60.42c. Each 1-hour average $SO_2$ emission rate must be based on at least 30 minutes of operation, and shall be calculated using the data points required under § 60.13(h)(2). Hourly $SO_2$ emission rates are not calculated if the affected facility is operated less than 30 minutes in a 1-hour period and are not counted toward determination of a steam generating unit operating day.

(c) The procedures under § 60.13 shall be followed for installation, evaluation, and operation of the CEMS.

(1) All CEMS shall be operated in accordance with the applicable procedures under Performance Specifications 1, 2, and 3 of appendix B of this part.

(2) Quarterly accuracy determinations and daily calibration drift tests shall be performed in accordance with Procedure 1 of appendix F of this part.

(3) For affected facilities subject to the percent reduction requirements under § 60.42c, the span value of the $SO_2$ CEMS at the inlet to the $SO_2$ control device shall be 125 percent of the maximum estimated hourly potential $SO_2$ emission rate of the fuel combusted, and the span value of the $SO_2$ CEMS at the outlet from the $SO_2$ control device shall be 50 percent of the maximum estimated hourly potential $SO_2$ emission rate of the fuel combusted.

(4) For affected facilities that are not subject to the percent reduction requirements of § 60.42c, the span value of the $SO_2$ CEMS at the outlet from the $SO_2$ control device (or outlet of the steam generating unit if no $SO_2$ control device is used) shall be 125 percent of the maximum estimated hourly potential $SO_2$ emission rate of the fuel combusted.

(d) As an alternative to operating a CEMS at the inlet to the $SO_2$ control device (or outlet of the steam generating unit if no $SO_2$ control device is used) as required under paragraph (a) of this section, an owner or operator may elect to determine the average $SO_2$ emission rate by sampling the fuel prior to combustion. As an alternative to operating a CEMS at the outlet from the $SO_2$ control device (or outlet of the steam generating unit if no $SO_2$ control device is used) as required under paragraph (a) of this section, an owner or operator may elect to determine the average $SO_2$ emission rate by using Method 6B of appendix A of this part. Fuel sampling shall be conducted pursuant to either paragraph (d)(1) or (d)(2) of this section. Method 6B of appendix A of this part shall be conducted pursuant to paragraph (d)(3) of this section.

(1) For affected facilities combusting coal or oil, coal or oil samples shall be collected daily in an as-fired condition at the inlet to the steam generating unit and analyzed for sulfur content and heat content according the Method 19 of appendix A of this part. Method 19 of appendix A of this part provides procedures for converting these measurements into the format to be used in calculating the average $SO_2$ input rate.

(2) As an alternative fuel sampling procedure for affected facilities combusting oil, oil samples may be collected from the fuel tank for each steam generating unit immediately after the fuel tank is filled and before any oil is combusted. The owner or operator of the affected facility shall analyze the oil sample to determine the sulfur content of the oil. If a partially empty fuel tank is refilled, a new sample and analysis of the fuel in the tank would be required upon filling. Results of the fuel analysis taken after each new shipment of oil is received shall be used as the daily value when calculating the 30-day rolling average until the next shipment is received. If the fuel analysis shows that the sulfur content in the fuel tank is greater than 0.5 weight percent sulfur, the owner or operator shall ensure that the sulfur content of subsequent oil shipments is low enough to cause the 30-day rolling average sulfur content to be 0.5 weight percent sulfur or less.

(3) Method 6B of appendix A of this part may be used in lieu of CEMS to measure $SO_2$ at the inlet or outlet of the $SO_2$ control system. An initial stratification test is required to verify the adequacy of the Method 6B of appendix A of this part sampling location. The stratification test shall consist of three paired runs of a suitable $SO_2$ and $CO_2$ measurement train operated at the candidate location and a second similar train operated according to the procedures in § 3.2 and the applicable procedures in section 7 of Performance Specification 2 of appendix B of this part. Method 6B of appendix A of this part, Method 6A of appendix A of this part, or a combination of Methods 6 and 3 of appendix A of this part or Methods 6C and 3A of appendix A of this part are suitable measurement techniques. If Method 6B of appendix A of this part is used for the second train, sampling time and timer operation may be adjusted for the stratification test as long as an adequate sample volume is collected; however, both sampling trains are to be operated similarly. For the location to be adequate for Method 6B of appendix A of this part 24-hour tests, the mean of the absolute difference between the three paired runs must be less than 10 percent (0.10).

(e) The monitoring requirements of paragraphs (a) and (d) of this section shall not apply to affected facilities subject to § 60.42c(h) (1), (2), or (3) where the owner or operator of the affected facility seeks to demonstrate compliance with the $SO_2$ standards based on fuel supplier certification, as described under § 60.48c(f), as applicable.

(f) The owner or operator of an affected facility operating a CEMS pursuant to paragraph (a) of this section, or conducting as-fired fuel sampling pursuant to paragraph (d)(1) of this section, shall obtain emission data for at least 75 percent of the operating hours in at least 22 out of 30 successive steam generating unit operating days. If this minimum data requirement is not met with a single monitoring system, the owner or operator of the affected facility shall supplement the emission data with data collected with other monitoring systems as approved by the Administrator.

**§ 60.47c Emission monitoring for particulate matter.**

(a) Except as provided in paragraphs (c), (d), (e), and (f) of this section, the owner or operator of an affected facility combusting coal, oil, or wood that is subject to the opacity standards under § 60.43c shall install, calibrate, maintain, and operate a COMS for measuring the opacity of the emissions discharged to the atmosphere and record the output of the system.

(b) All COMS for measuring opacity shall be operated in accordance with the

applicable procedures under Performance Specification 1 of appendix B of this part. The span value of the opacity COMS shall be between 60 and 80 percent.

(c) Affected facilities that burn only distillate oil that contains no more than 0.5 weight percent sulfur and/or liquid or gaseous fuels with potential sulfur dioxide emission rates of 26 ng/J (0.06 lb/MMBtu) heat input or less and that do not use a post-combustion technology to reduce $SO_2$ or PM emissions are not required to operate a CEMS for measuring opacity if they follow the applicable procedures under § 60.48c(f).

(d) Owners or operators complying with the PM emission limit by using a PM CEMS monitor instead of monitoring opacity must calibrate, maintain, and operate a CEMS, and record the output of the system, for PM emissions discharged to the atmosphere as specified in § 60.45c(d). The CEMS specified in paragraph § 60.45c(d) shall be operated and data recorded during all periods of operation of the affected facility except for CEMS breakdowns and repairs. Data is recorded during calibration checks, and zero and span adjustments.

(e) An affected facility that does not use post-combustion technology (except a wet scrubber) for reducing PM, $SO_2$, or carbon monoxide (CO) emissions, burns only gaseous fuels or fuel oils that contain less than or equal to 0.5 weight percent sulfur, and is operated such that emissions of CO to the atmosphere from the affected facility are maintained at levels less than or equal to 0.15 lb/MMBtu on a boiler operating day average basis is not required to operate a COMS for measuring opacity. Owners and operators of affected facilities electing to comply with this paragraph must demonstrate compliance according to the procedures specified in paragraphs (e)(1) through (4) of this section.

(1) You must monitor CO emissions using a CEMS according to the procedures specified in paragraphs (c)(1)(i) through (iv) of this section.

(i) The CO CEMS must be installed, certified, maintained, and operated according to the provisions in § 60.58b(i)(3) of subpart Eb of this part.

(ii) Each 1-hour CO emissions average is calculated using the data points generated by the CO CEMS expressed in parts per million by volume corrected to 3 percent oxygen (dry basis).

(iii) At a minimum, valid 1-hour CO emissions averages must be obtained for at least 90 percent of the operating hours on a 30-day rolling average basis. At least two data points per hour must be used to calculate each 1-hour average.

(iv) Quarterly accuracy determinations and daily calibration drift tests for the CO CEMS must be performed in accordance with procedure 1 in appendix F of this part.

(2) You must calculate the 1-hour average CO emissions levels for each steam generating unit operating day by multiplying the average hourly CO output concentration measured by the CO CEMS times the corresponding average hourly flue gas flow rate and divided by the corresponding average hourly heat input to the affected source. The 24-hour average CO emission level is determined by calculating the arithmetic average of the hourly CO emission levels computed for each steam generating unit operating day.

(3) You must evaluate the preceding 24-hour average CO emission level each steam generating unit operating day excluding periods of affected source startup, shutdown, or malfunction. If the 24-hour average CO emission level is greater than 0.15 lb/MMBtu, you must initiate investigation of the relevant equipment and control systems within 24 hours of the first discovery of the high emission incident and, take the appropriate corrective action as soon as practicable to adjust control settings or repair equipment to reduce the 24-hour average CO emission level to 0.15 lb/MMBtu or less.

(4) You must record the CO measurements and calculations performed according to paragraph (e) of this section and any corrective actions taken. The record of corrective action taken must include the date and time during which the 24-hour average CO emission level was greater than 0.15 lb/MMBtu, and the date, time, and description of the corrective action.

(f) An affected facility that burns only gaseous fuels or fuel oils that contain less than or equal to 0.5 weight percent sulfur and operates according to a written site-specific monitoring plan approved by the appropriate delegated permitting authority is not required to operate a COMS for measuring opacity. 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.

**§ 60.48c Reporting and recordkeeping requirements.**

(a) The owner or operator of each affected facility shall submit notification of the date of construction or reconstruction and actual startup, as provided by § 60.7 of this part. This notification shall include:

(1) The design heat input capacity of the affected facility and identification of fuels to be combusted in the affected facility.

(2) If applicable, a copy of any federally enforceable requirement that limits the annual capacity factor for any fuel or mixture of fuels under § 60.42c, or § 60.43c.

(3) The annual capacity factor at which the owner or operator anticipates operating the affected facility based on all fuels fired and based on each individual fuel fired.

(4) Notification if an emerging technology will be used for controlling $SO_2$ emissions. The Administrator will examine the description of the control device and will determine whether the technology qualifies as an emerging technology. In making this determination, the Administrator may require the owner or operator of the affected facility to submit additional information concerning the control device. The affected facility is subject to the provisions of § 60.42c(a) or (b)(1), unless and until this determination is made by the Administrator.

(b) The owner or operator of each affected facility subject to the $SO_2$ emission limits of § 60.42c, or the PM or opacity limits of § 60.43c, shall submit to the Administrator the performance test data from the initial and any subsequent performance tests and, if applicable, the performance evaluation of the CEMS and/or COMS using the applicable performance specifications in appendix B of this part.

(c) The owner or operator of each coal-fired, oil-fired, or wood-fired affected facility subject to the opacity limits under § 60.43c(c) shall submit excess emission reports for any excess emissions from the affected facility that occur during the reporting period.

(d) The owner or operator of each affected facility subject to the $SO_2$ emission limits, fuel oil sulfur limits, or percent reduction requirements under § 60.42c shall submit reports to the Administrator.

(e) The owner or operator of each affected facility subject to the $SO_2$ emission limits, fuel oil sulfur limits, or percent reduction requirements under § 60.42c shall keep records and submit reports as required under paragraph (d) of this section, including the following information, as applicable.

(1) Calendar dates covered in the reporting period.

(2) Each 30-day average $SO_2$ emission rate (ng/J or lb/MMBtu), or 30-day average sulfur content (weight percent), calculated during the reporting period, ending with the last 30-day period; reasons for any noncompliance with the

emission standards; and a description of corrective actions taken.

(3) Each 30-day average percent of potential $SO_2$ emission rate calculated during the reporting period, ending with the last 30-day period; reasons for any noncompliance with the emission standards; and a description of the corrective actions taken.

(4) Identification of any steam generating unit operating days for which $SO_2$ or diluent ($O_2$ or $CO_2$) data have not been obtained by an approved method for at least 75 percent of the operating hours; justification for not obtaining sufficient data; and a description of corrective actions taken.

(5) Identification of any times when emissions data have been excluded from the calculation of average emission rates; justification for excluding data; and a description of corrective actions taken if data have been excluded for periods other than those during which coal or oil were not combusted in the steam generating unit.

(6) Identification of the F factor used in calculations, method of determination, and type of fuel combusted.

(7) Identification of whether averages have been obtained based on CEMS rather than manual sampling methods.

(8) If a CEMS is used, identification of any times when the pollutant concentration exceeded the full span of the CEMS.

(9) If a CEMS is used, description of any modifications to the CEMS that could affect the ability of the CEMS to comply with Performance Specifications 2 or 3 of appendix B of this part.

(10) If a CEMS is used, results of daily CEMS drift tests and quarterly accuracy assessments as required under appendix F, Procedure 1 of this part.

(11) If fuel supplier certification is used to demonstrate compliance, records of fuel supplier certification is used to demonstrate compliance, records of fuel supplier certification as described under paragraph (f)(1), (2), (3), or (4) of this section, as applicable. In addition to records of fuel supplier certifications, the report shall include a certified statement signed by the owner or operator of the affected facility that the records of fuel supplier certifications submitted represent all of the fuel combusted during the reporting period.

(f) Fuel supplier certification shall include the following information:

(1) For distillate oil:

(i) The name of the oil supplier;

(ii) A statement from the oil supplier that the oil complies with the specifications under the definition of distillate oil in § 60.41c; and

(iii) The sulfur content of the oil.

(2) For residual oil:

(i) The name of the oil supplier;

(ii) The location of the oil when the sample was drawn for analysis to determine the sulfur content of the oil, specifically including whether the oil was sampled as delivered to the affected facility, or whether the sample was drawn from oil in storage at the oil supplier's or oil refiner's facility, or other location;

(iii) The sulfur content of the oil from which the shipment came (or of the shipment itself); and

(iv) The method used to determine the sulfur content of the oil.

(3) For coal:

(i) The name of the coal supplier;

(ii) The location of the coal when the sample was collected for analysis to determine the properties of the coal, specifically including whether the coal was sampled as delivered to the affected facility or whether the sample was collected from coal in storage at the mine, at a coal preparation plant, at a coal supplier's facility, or at another location. The certification shall include the name of the coal mine (and coal seam), coal storage facility, or coal preparation plant (where the sample was collected);

(iii) The results of the analysis of the coal from which the shipment came (or of the shipment itself) including the sulfur content, moisture content, ash content, and heat content; and

(iv) The methods used to determine the properties of the coal.

(4) For other fuels:

(i) The name of the supplier of the fuel;

(ii) The potential sulfur emissions rate of the fuel in ng/J heat input; and

(iii) The method used to determine the potential sulfur emissions rate of the fuel.

(g)(1) Except as provided under paragraphs (g)(2) and (g)(3) of this section, the owner or operator of each affected facility shall record and maintain records of the amount of each fuel combusted during each operating day.

(2) As an alternative to meeting the requirements of paragraph (g)(1) of this section, the owner or operator of an affected facility that combusts only natural gas, wood, fuels using fuel certification in § 60.48c(f) to demonstrate compliance with the $SO_2$ standard, fuels not subject to an emissions standard (excluding opacity), or a mixture of these fuels may elect to record and maintain records of the amount of each fuel combusted during each calendar month.

(3) As an alternative to meeting the requirements of paragraph (g)(1) of this section, the owner or operator of an affected facility or multiple affected facilities located on a contiguous property unit where the only fuels combusted in any steam generating unit (including steam generating units not subject to this subpart) at that property are natural gas, wood, distillate oil meeting the most current requirements in § 60.42C to use fuel certification to demonstrate compliance with the $SO_2$ standard, and/or fuels, excluding coal and residual oil, not subject to an emissions standard (excluding opacity) may elect to record and maintain records of the total amount of each steam generating unit fuel delivered to that property during each calendar month.

(h) The owner or operator of each affected facility subject to a federally enforceable requirement limiting the annual capacity factor for any fuel or mixture of fuels under § 60.42c or § 60.43c shall calculate the annual capacity factor individually for each fuel combusted. The annual capacity factor is determined on a 12-month rolling average basis with a new annual capacity factor calculated at the end of the calendar month.

(i) All records required under this section shall be maintained by the owner or operator of the affected facility for a period of two years following the date of such record.

(j) The reporting period for the reports required under this subpart is each six-month period. All reports shall be submitted to the Administrator and shall be postmarked by the 30th day following the end of the reporting period.

**Appendix B—[Amended]**

■ 7. Appendix B to part 60 is amended by revising section 8.3.1 in Performance Specification 2, to read as follows:

**Appendix B to Part 60—Performance Specifications**

* * * * *

*Performance Specification 2—Specifications and Test Procedures for $SO_2$ and $NO_x$ Continuous Emission Monitoring Systems in Stationary Sources*

* * * * *

8.3.1 *CD Test Period.* While the affected facility is operating, determine the magnitude of the CD once each day (at 24-hour intervals) for 7 consecutive calendar days according to the procedure given in Sections 8.3.2 through 8.3.4. Alternatively, the CD test may be conducted over 7 consecutive unit operating days.

* * * * *

**Appendix F—[Amended]**

■ 8. Procedure 1 in Appendix F to part 60 is amended by:
■ a. Revising the first sentence of section 5.1.1; and
■ b. Revising section 5.1.4.
The revisions read as follows:

**Appendix F to Part 60—Quality Assurance Procedures**

* * * * *

5.1.1 Relative Accuracy Test Audit (RATA). The RATA must be conducted at least once every four calendar quarters, except as otherwise noted in section 5.1.4 of this appendix.

* * * * *

5.1.4 Other Alternative Audits. Other alternative audit procedures may be used as approved by the Administrator for three of four calendar quarters. One RATA is required at least every four calendar quarters, except in the case where the affected facility is off-line (does not operate) in the fourth calendar quarter since the quarter of the previous RATA. In that case, the RATA shall be performed in the quarter in which the unit recommences operation. Also, cylinder gas audits are not be required for calendar quarters in which the affected facility does not operate.

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[FR Doc. E7–7673 Filed 6–12–07; 8:45 am]
BILLING CODE 6560–50–P

APPENDIX B

# *FISCAL NOTE FOR PROPOSED RULES*

Rule Title: 45CSR16 - "Standards of Performance for New Stationary Sources"

Type of Rule: ___X__ Legislative _____Interpretive _____Procedural

Agency: Division of Air Quality

Address: 601 57th Street SE
Charleston, WV 25304

FILED IN THE OFFICE OF
THE SECRETARY OF STATE
THIS DATE 7/11/08
ADMINISTRATIVE LAW DIVISION

Phone Number: 926-0475 Email: tmowrer@wvdep.org

## Fiscal Note Summary

Summarize in a clear and concise manner what impact this measure will have on costs and revenues of state government.

No impact above that resulting from currently applicable federal emission standards.

## Fiscal Note Detail

Show over-all effect in Item 1 and 2 and, in Item 3, give an explanation of Breakdown by fiscal year, including long-range effect.

**FISCAL YEAR**

| Effect of Proposal | 2009 Increase/Decrease (use "-") | 2010 Increase/Decrease (use "-") | Fiscal Year (Upon Full Implementation) |
|---|---|---|---|
| **1. Estimated Total Cost** | $ 0 | $ 0 | $ 0 |
| Personal Services | 0 | 0 | 0 |
| Current Expenses | 0 | 0 | 0 |
| Repairs & Alterations | 0 | 0 | 0 |
| Assets | 0 | 0 | 0 |
| Equipment | 0 | 0 | 0 |
| Other | 0 | 0 | 0 |
| **2. Estimated Total Revenues** | 0 | 0 | 0 |

Rule Title: 45CSR16 - "Standards of Performance for New Stationary Sources"

**3. Explanation of above estimates (including long-range effect):**
Please include any increase or decrease in fees in your estimated total revenues.

Costs anticipated to be incurred in the implementation of federal rules promulgated under 40 CFR Part 60 as of June 1, 2008 are included in prior cost estimates prepared for state implementation of Title V of the Clean Air Act, as amended, under 45CSR30. Full Title V program approval was issued by the U.S. Environmental Protection Agency on November 19, 2001.

## MEMORANDUM

Please identify any areas of vagueness, technical defects, reasons the proposed rule **would not** have a fiscal impact, and/or any special issues **not** captured elsewhere on this form.

Date: 7/11/08

Signature of Agency Head